Some Aspects of Distribution System Planning in the Context of Investment in Distributed Generation

by

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I hereby declare that I am the sole author of this thesis. This is a true copy of the thesis, including any required final revisions, as accepted by my examiners.

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Abstract

A paradigm shift in distribution system design and planning is being led by the deregulation of the power industry and the increasing adoption of distributed generation (DG). Technology advances have made DG investments feasible by both local distribution companies (LDCs) and small power producers (SPPs). LDCs are interested in finding optimal long term plans that best serve their customers at the lowest cost. SPPs, as private entities, are concerned about maximizing their rates of return. Also keenly interested in distribution design and planning is the government, which, through an electricity regulator, strives to meet DG penetration and emissions reduction goals through policy implementations.

This thesis first examines the distribution system planning problem from the LDC's perspective. An innovative hierarchical dynamic optimization model is proposed for the planning of distribution systems and the energy scheduling of units that is also capable of reconciling uncoordinated SPP investments in DG. The first stage of the two-stage framework consists of a siting-cum-period planning model that sets element sizing and commissioning dates. The second stage consists of a capacity-cum-production planning model that finalizes element capacities and energy import/export and production schedules. The proposed framework is demonstrated on a 32-bus radial distribution system. Four case studies encompassing different policy sets are also conducted, demonstrating that this model's usefulness also extends to predicting the impact of different energy policies on distribution system operation and economics.

The analysis of different policy sets is further expanded upon through the proposal of a new mathematical model that approaches the distribution design problem from the regulator's perspective. Various case studies examining policies that may be used by the regulator to meet DG penetration and emissions goals, through DG investment, are constructed. A combination of feed-in-tariffs, CO_2 tax, and cap-and-trade mechanisms are among the policies studied. The results, in the context of Ontario, Canada and its Standard Offer Program, are discussed, with respect to achieving objectives in DG investment, participation by SPPs, consumer costs, and uncertainty in carbon market prices.

In jurisdictions such as Ontario, the LDC cannot invest in its own DG capacity but must accommodate those of SPPs. With the successful implementation of DG investment incentives by the regulator, there is a potential for significant investments in DG by SPPs, which may exceed that of the LDCs ability to absorb. This thesis proposes a novel method that can be used by the regulator or LDC to fairly assess, coordinate, and approve multiple competing investments proposals while maintaining operational feasibility of the distribution system. This method uses a feedback between the LDC and SPPs to achieve maximum investor participation while adhering to the technical operational limits of the distribution system. The proposed scheme is successfully demonstrated on a 32-bus radial distribution system, where it is shown to increase SPP-DG investments and production, improve the system's voltage profile, and reduce losses.

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First, I would like to acknowledge and thank the Lord, for the work He has done in my life, and for giving me the wisdom and foundation to make this thesis possible.

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Abbreviations

AACR: Annual avoided charge rate
AFCR: Annualized fixed charge rate
CESOP: Clean Energy Standard Offer Program
CHP: Combined heat and power
CO_2: Carbon dioxide
CPPM: Capacity-cum-production planning model
DER: Distributed energy resources
DG: Distributed generation
DGCA: Distributed generation coordination algorithm
DSM: Demand side management
ECF: Expected capacity factor
EOL: End-of-life
EPC: Engineering, procurement, and construction
FIT: Feed-in-tariff
GA: Genetic algorithm
HOEP: Hourly Ontario electric price
IPSP: Integrated power system plan
ISO: Independent system operator
LDC: Local distribution company
LP: Linear program
MILP: Mixed-integer linear program
MINLP: Mixed-integer non-linear program
NLP: Non-linear program
NO_x: Nitrogen oxide
NPC: Net present cost
OEB: Ontario Energy Board
OPA: Ontario Power Authority
OR: Operations research
PV: Photovoltaic
REC: Renewable energy certificate
RESOP: Renewable Energy Standard Offer Program
RPS: Renewable portfolio standard
SO_2: Sulphur dioxide
SOP: Standard Offer Program

SPP:	Small power producer
SPPM:	Siting-cum-period planning model
TGC:	Tradable green certificate

Nomenclature

Sets and Indices

Symbol	Definition	Chapter 3	Chapter 4	Chapter 5
b	Load block, e.g. peak, intermediate, base	✓	✓	✓
B	Set of load blocks ($b \in B$)	✓	✓	✓
g	Distributed generation (DG) unit		✓	✓
G	Set of DG-units		✓	✓
k	Small power producer (SPP)	✓	✓	✓
K	Set of SPPs ($k \in K$)	✓	✓	✓
K^{nd}	Subset of non-dispatchable SPPs ($K^{nd} \subset K$)			✓
i, j	Bus	✓	✓	✓
N	Set of buses in distribution system ($i, j \in N$)	✓	✓	✓
N^{cap}	Subset of buses with capacitors ($N^{cap} \subset N$)			✓
N^{int}	Subset of buses with interties ($N^{int} \subset N$)	✓		✓
N_x^{loop}	Subset of buses comprising loop x ($N_x^{loop} \subset N$)	✓		
N_k^{SPP}	Subset of possible SPP-DG sites ($N_k^{spp} \subset N$)	✓		
N^{ss}	Subset of buses with substations ($N^{ss} \subset N$)	✓	✓	✓
q	DG technology	✓	✓	
Q	Set of DG technologies ($q \in Q$)	✓	✓	
Q^d	Subset of dispatchable DG technologies ($Q^d \subset Q$)		✓	
Q^{nd}	Subset of non-dispatchable DG technologies ($Q^{nd} \subset Q$)		✓	
t, t'	Year	✓	✓	✓
T	Overall planning horizon ($t, t' \in T$)	✓	✓	✓

Parameters

Symbol	Definition	Chapter 3	Chapter 4	Chapter 5
$\alpha^{dg}_{k,t}$	Salvage value of DG-unit (% of initial cost)			✓
$\alpha^{dg}_{k,q,t}$	" "		✓	
$\alpha^{dg}_{q,t}$	" "		✓	
$absZ_{(i,j),t}$	Absolute value of impedance (i,j) (p.u.)	✓		
β	Number of updates to DG-unit production limits			✓
$Bb_{(i,j)}$	$\Im\big($Y-bus element $(i,j)\big)$			✓
Bgt^{LDC}_{t}	LDC's annual capital budget ($)	✓		
Bgt^{SPP}_{k}	SPP's capital budget (discounted to year-0) ($)			✓
$Cc^{dg.f}_{k,t}$/	Engineering, procurement, and construction			✓
$Cc^{dg.f}_{q,t}$	(EPC) fixed cost of DG-unit ($)	✓		
$Cc^{dg.v}_{k,t}$/	Variable capital cost of DG unit ($/MW)			✓
$Cc^{dg.v}_{q,t}$	" "		✓	
$Cc^{fdr.f}_{t}$	EPC cost of feeder upgrade ($/km)	✓		
$Cc^{fdr.v}_{t}$	Variable capital cost of feeder ($/MW)	✓		
$Cc^{int.f}_{t}$	EPC cost of intertie upgrade ($)	✓		
$Cc^{int.v}_{t}$	Variable capital cost of intertie ($/MW)	✓		
$Cc^{ss.f}_{t}$	EPC cost of substation upgrade ($)	✓		
$Cc^{ss.v}_{t}$	Variable capital cost of substation ($/MW)	✓		
Ce^{cap}	Operating cost of capacitor ($/MVar)			✓
$Ce^{dg}_{q,b,t}$/	Price of energy from SPP-DG ($/MWh)		✓	✓
$Ce^{dg}_{k,b,t}$	" "	✓		
$Ce^{dg.FIT}_{k,b,t}$/	Feed-in-tariff (FIT) for DG ($/MWh)			✓
$Ce^{dg.FIT}_{q,b,t}$	" "		✓	
$Ce^{int}_{b,t}$	Price of energy from intertie ($/MWh)	✓	✓	✓
$Ce^{ss}_{b,t}$	Market price of energy ($/MWh)	✓	✓	✓
$Cntrb^{dg.fdr}_{g,(i,j),b,t}$	Feeder power flow contribution from DG unit (%)			✓
$Ce^{x}_{b,t}$	Price received for exported energy ($/year)	✓		
$Co^{dg}_{q,t}$/	Operating cost of DG unit ($/MWh)	✓	✓	
$Co^{dg}_{k,t}$	" "			✓

Symbol	Definition	Chapter 3	4	5
$CO2^{dg}_{k}$/	CO_2 emissions from DG unit (t/MWh)	✓		
$CO2^{dg}_{q}$	" "	✓	✓	
$CO2^{ss}_{b,t}$	CO_2 emissions from bulk generation (t/MWh)	✓	✓	
$CO2^{cap}_{t}$	CO_2 emissions cap (t/MWh)	✓	✓	
$Ct^{CO_2}_{t}$	CO_2 emissions tax ($/t)	✓	✓	
DG^{max}	Maximum DG penetration (% of demand)	✓	✓	
DG^{min}	Minimum DG penetration (% of demand)	✓		
$ECF_{k,i,b}$/	Expected capacity factor of DG unit (%)			✓
$ECF_{q,i,b}$	" "	✓	✓	
$Ge_{(i,j)}$	Geographic cost factor of feeder between (i, j)	✓		
$Gg_{(i,j)}$	$\Re($Y-bus element $(i, j))$			✓
H	Planning horizon (years)	✓	✓	✓
Hi	Upper bound on CPPM variables set in SPPM (%)	✓		
Hrs_{b}	Hours per year in load demand block	✓	✓	✓
$Le_{(i,j)}$	Length between (i, j) (km)	✓		
$Ll^{fdr}_{(i,j),t}$	Estimated loss on feeder (i, j) (%)	✓	✓	
Lo	Lower bound on CPPM variables set in SPPM (%)	✓		
Ls^{dg}_{k}/	DG unit lifespan (years)			✓
Ls^{dg}_{q}	" "		✓	
M	Big number used in MIP modelling	✓	✓	✓
M^{fdr}	Penalty for feeder overload in CPPM ($/MW)	✓		
M^{rdn}	Factor prioritizing overload reduction			✓
$M^{dg.co}_{b,t}$	DG unit constrain-off avoidance factor ($/MWh)			✓
$Op_{k,t}$	Operating year(s) of k (0/1)	✓		
$P^{dg}_{g,b,t}$	Power from DG unit (MW)			✓
$P^{dg.max}_{k,i,b,t}$	SPP DG unit production limits (MW)		✓	✓
$P.ovld^{fdr}_{(i,j),b,t}$	Power flow exceeding feeder capacity (MW)			✓
$P.rdn^{dg}_{g,b,t}$	Reduction in DG unit output (MW)			✓
$Pd_{i,b,t}$	Active power demand (MW)	✓	✓	✓
$P^{x.max}$	Substation export capacity (MW)		✓	
$Qd_{i,b,t}$	Reactive power demand (MW)			✓

Symbol	Definition	Chapter 3	Chapter 4	Chapter 5
R^{LDC}	LDC's discount rate (%)		✓	✓
$R^{LDC.c}$	LDC's discount rate for capital (%)	✓		
$R^{LDC.e}$	LDC's discount rate for energy (%)	✓		
R_k^{SPP}	SPP's discount rate (%)	✓	✓	✓
Rs	Reserve margin (% of demand)	✓		
$sp.$	Prefix denoting value from the SPPM solution	✓		
SS^{max}	Maximum number of substations	✓		
V^{max}	Maximum bus voltage limit (p.u.)	✓	✓	✓
V^{min}	Minimum bus voltage limit (p.u.)	✓	✓	✓
$W_{i,t}^{cap}$	Capacitor size (MVar)	✓		✓
$W_{q,i}^{dg.ini}$	Initial DG unit size (MW)	✓		
$W_k^{dg.max}/$	Maximum DG unit size (MW)			✓
$W_{k,q}^{dg.max}/$	" "		✓	
$W_q^{dg.max}$	" "	✓		
$W_{k,q}^{dg.min}$	Minimum DG unit size (MW)		✓	
$W_q^{dg.min}$	Minimum DG unit size (MW)	✓		
W_k^{dg}	SPP DG unit size (MW)	✓		
$W_{(i,j),t}^{fdr.st}/$	Existing feeder/intertie/substation (step)	✓		
$W_{(i,j),t}^{int.st}/$	capacity – changes from year to year	✓		
$W_{i,t}^{ss.st}$	up to end of life (MW)	✓		
$W_{i,t}^{int}$	Intertie capacity (MW)	✓		✓
$W_{i,t}^{ss}$	Substation capacity (MW)	✓		✓
$W_i^{int.max}$	Maximum intertie build size (MW)	✓		
$W_i^{ss.max}$	Maximum substation build size (MW)	✓		
$W_i^{ss.min}$	Minimum substation build size (MW)	✓		
$Z_{k,i,b,t}^{dg.max}$	DG unit production constrained flag (0/1)			✓

Variables

Symbol	Definition	Chapter 3	Chapter 4	Chapter 5
$\theta_{i,b,t}$	Voltage angle (rad.)			✓
$CO2_t^{xs}$	CO_2 emissions in excess of $CO2^{cap}$ (t)			✓
$P_{k,i,b,t}^{dg}$	SPP-DG production (MW)	✓		✓
$P_{k,q,i,b,t}^{dg}$	" "		✓	
$P_{q,i,b,t}^{dg}$	Utility-DG production (MW)	✓	✓	
$P_{(i,j),b,t}^{fdr}$	Power flow on feeder between (i,j) (MW)	✓		
$P_{i,b,t}^{int}$	Intertie power import/export (MW)	✓		✓
$P_{i,b,t}^{ss}$	Substation power import/export (MW)	✓	✓	✓
$P.co_{g,b,t}^{dg}$	DG unit power constrained-off (MW)			✓
$P.ovld_{(i,j),b,t}^{fdr.r}$	Remaining feeder power flow overload (MW)			✓
$P.rdn_{(i,j),b,t}^{fdr}$	Feeder power flow reduction (MW)			✓
$P.sub_{g,b,t}^{dg}$	Subtraction in DG unit output (MW)			✓
$P_{i,b,t}^{x}$	Power export to grid (MW)	✓	✓	
$Q_{i,b,t}^{cap}$	Reactive power output from capacitor (MVar)			✓
$V_{i,b,t}$	Voltage (p.u.)	✓	✓	✓
$w_{k,i,t}^{dg}$	Capacity added to DG unit (MW)		✓	✓
$w_{k,q,i,t}^{dg}$	" "		✓	
$w_{q,i,t}^{dg}$	Capacity added to DG unit(MW)	✓		
$w_{(i,j),t}^{fdr}$	Capacity added to feeder (i,j) (MW)	✓		✓
$w_{(i,j),t}^{fdr.pen}$	Penalized capacity addition to feeder (i,j) (MW)	✓		
$w_{i,t}^{int}$	Capacity added to intertie (MW)	✓		
$w_{i,t}^{ss}$	Capacity added to substation (MW)	✓		
$z_{k,i,t}^{dg}/$	Decision on DG build/upgrade (0/1)			✓
$z_{k,q,i,t}^{dg}/$	" "	✓	✓	
$z_{q,i,t}^{dg}$	" "	✓	✓	
$z_{i,k}^{dg^P}$	Decision on SPP-DG k location (0/1)	✓		
$z_{(i,j),t}^{fdr}$	Decision on feeder build/upgrade (0/1)	✓		

Symbol	Definition	Chapter 3	4	5
$z_{i,t}^{int}$	Decision on intertie build/upgrade (0/1)	✓		
$z_{(i,j),b,t}^{pf}$	Power flow directional flag (0/1)	✓	✓	
$z_{i,t}^{ss}$	Decision on substation build/upgrade (0/1)	✓		
z_{i}^{ss}	Substation at site flag (0/1)	✓		
$z.rdn_{g,b,t}^{dg}$	DG unit production limited (0/1)			✓

Chapter 1

Introduction

1.1 Introduction

Policy changes and advancements in distributed generation (DG) technologies are introducing paradigm shifts in distribution systems design, planning, and operation. The transition of the electric power industry from a regulated monopoly to a competitive market has been the largest seen of any industry [1]. Deregulation has affected not only generators but many local distribution companies (LDCs) who now must decide from whom to purchase energy.

At the same time, technological advances have also led to the ascent of DG as a viable alternative for meeting the energy needs of distribution systems. With DG, LDCs, now, have the option of placing generating sources within their distribution system instead of purchasing from bulk generation; alternatively, in a deregulated environment they may be obliged to permit small power producers (SPPs) to install DG units in their system.

In addition, changes to the design, planning, and operation of distribution systems are being driven by policies aimed at mitigating emissions from electricity generation. These policies may include incentives aimed at encouraging investment in sources of clean or renewable energy, which includes a good portion of DG technology. Other environmental-based policy initiatives are carbon tax and cap-and-trade mechanisms, which create additional costs that, however, need to be factored into the price of energy.

This thesis will explore some aspects of the planning of distribution systems, in the context of investment in DG driven by the aforementioned factors. In this chapter, a definition and brief review of distribution systems will be given in Section 1.2, followed by a review of distributed energy resources (DER), including DG, in Section 1.3, and an introduction to deregulation in Section 1.4. Finally, an overview of the research and the motivation behind it will be presented in Section 1.5.

1.2 Distribution Systems

The chief constituents of the bulk electric power system are generation, transmission/sub-transmission, and distribution. Traditionally, the transmission system carries electricity from the bulk generation system to the sub-transmission system at voltage levels of 230 kV or higher. The sub-transmission system then transfers the power at voltage levels between 69 kV – 138 kV to the distribution systems. Finally, the distribution systems, at voltages typically under 34.5 kV, delivers electricity to the consumer. An illustration of a typical bulk electric power system is given in Figure 1.1. The distribution system is highlighted.

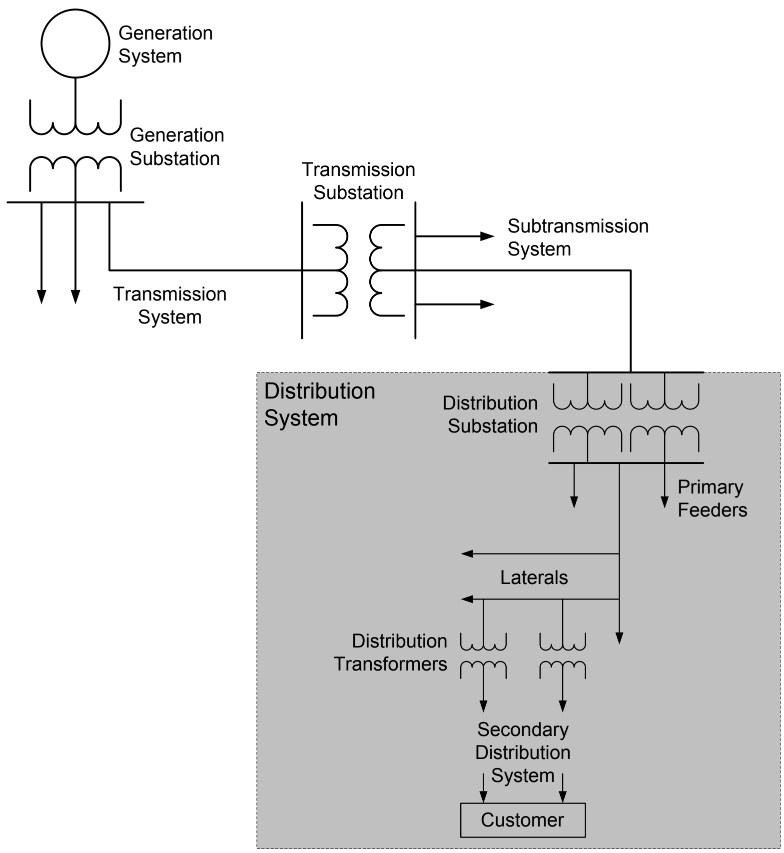

Figure 1.1: Typical Representation of a Bulk Electric Power System

The distribution system can be divided into primary and secondary systems. The primary distribution system consists of distribution substations and feeders. The distribution substations step down power from the sub-transmission system to between 4.16 kV and 34.5 kV. From there, electricity is distributed through primary feeders, and then lateral feeders, to the secondary distribution system. At the secondary distribution system electricity is stepped down to between 120/240 and 480 V, which can be used directly by the consumer. Note that large industrial customers may connect to any point along the network. The research presented in this thesis is concerned with the primary distribution system, traditionally consisting of distribution substations and primary feeders at the 4.16 kV to 34.5 kV voltage level. Laterals and the secondary distribution system are aggregated as loads along the primary feeder.

1.2.1 Configuration

There are three common distribution system design configurations: radial, loop, and network, as illustrated in Figures 1.2, 1.3, and 1.4, respectively [2].

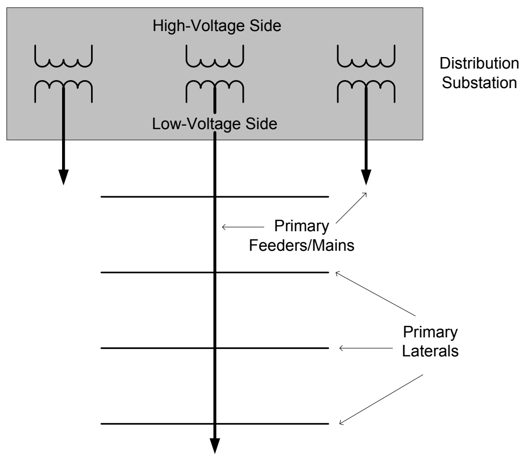

Figure 1.2: Primary Distribution System – Radial Configuration

The radially configured distribution system is the most common. In comparison to the other two configurations it has the lowest capital cost; however, it also has the lowest reliability, since any faults in the feeders will cause service interruptions at all points downstream. On the other hand, network configured distribution systems are the most reliable, but its numerous feeders with associated protection and control systems also make it the most expensive. Network configurations may be used in high density areas, such as downtown cores. Loop configured distribution systems fall in between the two in terms of cost and reliability. They require higher capacity cabling than radial systems, but can also redistribute power flows in the case of a fault, maintaining service.

1.2.2 Infrastructure Design and Planning

The classical approach to distribution system design and planning first involves load forecasting. This is followed by the siting and optimum sizing of substations, and finally feeder routing and design [3]. Different methods and techniques for distribution planning are covered in Chapter 2.

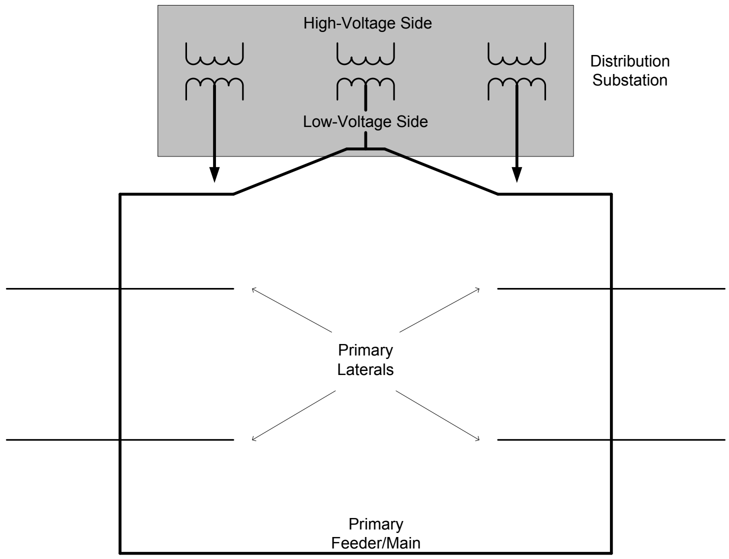

Figure 1.3: Primary Distribution System – Loop Configuration

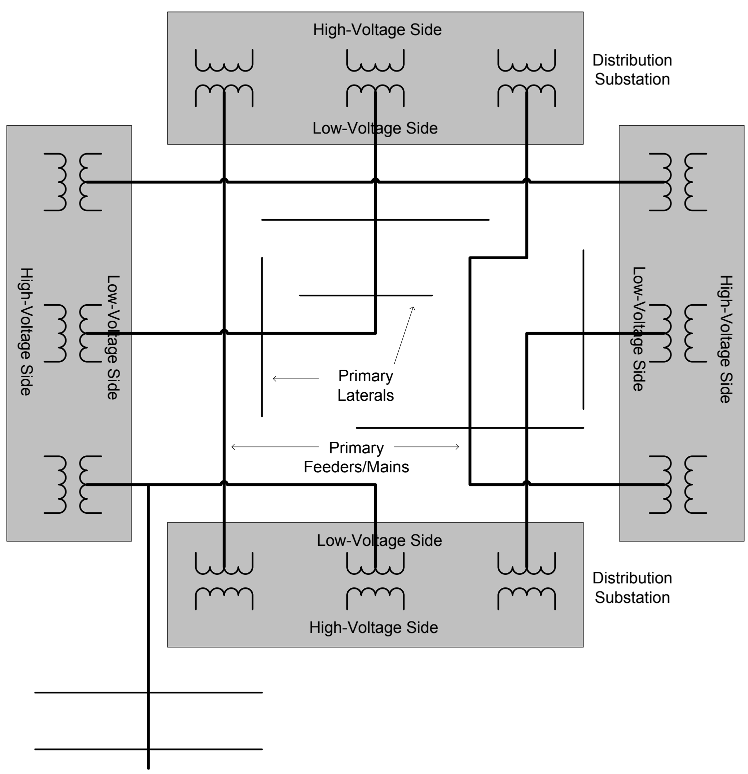

Figure 1.4: Primary Distribution System – Network Configuration

1.3 Distributed Generation

DER, also called distributed resources (DR), are "demand and supply-side resources that can be deployed throughout an electric power distribution system (...) to meet the energy and reliability needs of the customers served by that system... installed on either the customer side or the utility side of the meter" [4]. Distributed generation, storage resources, and demand side management (DSM) options fall under this definition.

Gellings [5] describes DSM as "the planning, implementation, and monitoring of those utility activities designed to influence customer use of electricity in ways that will produce desired changes in the utility's load shape." These measures are enacted by utilities to optimize the use of available energy; examples include the addition of thermal storage units or the promotion and installation of energy efficient appliances. Storage resources allow electricity to be stored for later use, such as backup power or peak shaving. Typical technologies used in this application include flywheels and batteries. DG is the primary subject of this thesis and is discussed below.

1.3.1 Definition

DG is succinctly defined as "electric power source[s] connected directly to the distribution network or on the customer side of the meter" [6]. This definition is accommodating, allowing a variety of technologies and implementations across different utility structures, while avoiding the pitfalls of using more stringent criteria based on rules such as power ratings and power delivery area.

Two categories for the classification of DG are also proposed in [6]. The first classification is based upon unit capacity:

- Micro 1 W - 5 kW
- Small 5 kW - 5 MW
- Medium 5 MW - 50 MW
- Large 50 MW - 300 MW (rare)

The second classification is based on technology:

- Renewable
- Modular
- Combined heat and power (CHP)

DG units based on renewable energy resources can be readily replenished and are viewed as 'environmentally friendly'. Modular DG refers to units that can be built and placed within a short time span and can be operated together (as distinct units) to meet larger output requirements. All DG units will be regarded as modular in this thesis. Combined heat and power (CHP) units, discussed later, generate usable process heat as well as electric power.

1.3.2 Technologies

Several technologies can be used for DG systems, as identified by Püttgen *et al.* [7], Zareipour *et al.* [8], and the International Energy Agency [9]. These technologies and their characteristics are summarized in Table 1.1.

Biogas

Biogas plants use biomass waste products from agricultural activities, using anaerobic biodigesters to create natural gas that can be used to generate electricity and heat. Although these plants produce emissions, these emissions are less than what would have otherwise been emitted from the unused biomass fuel.

Fuel Cells

There are various fuel cell technologies available – all use interactions between hydrogen and oxygen to generate electricity. Although comparatively very expensive, they operate silently and produce much lower levels of CO_2 and NO_x emissions.

Micro-hydro

Micro-hydro technology is another emission-free technology – however their placement is confined to where there is adequate water flow.

Reciprocating Engines

Reciprocating engine technology is the most prevalent DG unit technology [9]. Reliable, these engines use cylinders and pistons to generate power (the internal combustion engines of cars use this technology). However, they are also noisy, and their use of fossil fuels means that they emit high levels of CO_2 and NO_x gases, as can be seen in Table 1.1.

Small Gas Turbines and Microturbines

Turbines essentially use the same technology as those of jet engines. Having lower electrical efficiencies than that of the engines, their total output of useful energy can be greatly increased if these systems are used in CHP applications. They are also noisy, but have lower NO_x emissions than other engine types.

Table 1.1: Summary of Typical DG Technologies [9], [10], [11], [12]

Technology	Usage				Typical Size	Cost			Emissions (kg/MWh)	
	Res	Com	Ind	Rem		Capital ($/kW)	O&M ($/MWh)	Fuel ($/MWh)	CO_2	NO_x
Biogas			Y		15 kW – 5 MW	4,000	0[1]	0[1]	negative[2]	negative[2]
High Temp. Fuel Cell		Y	Y	P	50 kW – 3 MW	1,000 – 2,000	5 – 10	430 – 490	88 – 112	0.005 – 0.01
Low Temp. Fuel Cell (PAFC)	Y	Y			50 – 500 kW	3,000	5 – 10	88 – 112	430 – 490	0.005 – 0.01
Low Temp. Fuel Cell (PEM)	Y	Y	P	P	1 – 250 kW	1,000 – 2,000	5 – 10	88 – 112	430 – 490	0.005 – 0.01
Gas Turbine		Y	Y	P	500 kW – 20 MW	650 – 900	3 – 8	48 – 72	580 – 680	0.3 – 0.5
Microturbine		Y	Y	P	25 – 500 kW	1,000 – 1,300	5 - 10	56 – 72	720	0.1
Reciprocating Engine (Diesel)	Y	Y	Y	P	20 kW – 10 MW	350 – 500	5 – 10	56 – 88	650	10
Reciprocating Engine (Gas)	Y	Y	Y	P	50 kW – 5 MW	600 – 10,00	7 – 15	48 – 72	500 – 620	0.2 – 1.0
Solar-Photovoltaic	Y		P	Y	0.05 – 200 kW	5,000 – 10,000	1 – 4	0	0	0
Stirling Engines		Y		P	0.5 – 200 kW	700 - -1,500	Varies by Fuel Type			
Wind Turbines	Y	Y	Y	Y	1 kW – 2.5 MW	1,500 – 3,000	10	0	0	0

Res: Residential Customer; Com: Commercial Customer; Ind: Industrial Customer; Rem: Remote Customer

Y: Yes; P: Potential

[1]: Biogas fuel costs may be offset by biomass gate fees and sale of by-products.

[2]: Emissions from biogas plants are less than that from unused biomass, resulting in a net reduction in emissions.

Solar-Photovoltaic (PV) Cells

Solar-PV technologies harness sunlight to produce electrical power; to their advantage they are emissions free and have very low operating costs. However, they cannot be placed in all locations and high capital costs limit their wide-spread adoption; also, without storage support their output is non-uniform.

Stirling Engines

Stirling engines differ from most reciprocating engines in that the gas within the piston assembly is sealed - the heat used to generate power is external to the assembly. This engine type has low noise levels and can be adapted for many fuel types (any source of heat), though it is more expensive than the reciprocating engine.

Wind Turbines

Wind turbines, like solar-PV technology, are also emissions free; they derive their electricity from wind. They are commonly used in wind farms with many units operating together (outside the definition of DG), although they can be used in standalone mode as DG. They have similar drawbacks as solar-PV technology: high cost, limited placement possibilities, and non-uniform output.

1.3.3 Applications

DG units have many possible applications within the distribution system, such as backup (standby) power, peak shaving, export to the distribution grid, CHP, reactive power and voltage support, and island operation during faults. One of the important applications of DG, the possibility of combined heat and power generation, is discussed below.

CHP Generation

CHP, also known as cogeneration, is the generation of both utilizable heat and electric energy through a single process. This leads to a significant increase in overall efficiency compared to standalone synchronous generators. Unlike utility based electricity generation, the energy from CHP systems are generally used locally, within the customer site where the system is located. CHP systems are practical and feasible in systems with a simultaneous demand for process steam (or heat) and electricity, for example, in hospitals and universities, industrial plants, and district heating applications.

There are two types of cycles within CHP plants: topping cycle and bottoming cycle. Topping cycle refers to systems where electrical energy is generated first followed by the production of useful heat from the rejected exhaust gases or steam from the previous process. In the case of bottoming cycle the procedure is reversed, and heat is first generated (usually for an industrial process) and then used to generate electric power.

1.3.4 Benefits and Costs

Among the various possible benefits of DG, some of the significant ones are accessibility in remote communities, reduction in feeder loadings, reduced feeder loss, scalability, reduced costs, environmental sustainability, contribution to voltage support, and increased reliability. Some approaches to quantify the environmental, line-loss, voltage profile, power quality and reliability benefits of DG are discussed in [13] and [14].

Two related benefits of DGs over centralized generation pertain to transmission of energy: reduced line losses and reduced network congestion [13]. Reduced line losses result from DG units being typically placed closer to customers than central generation, thus avoiding the long transmission distances and associated losses. Depending on the placement of DG units, feeder overloads can also be reduced through counter-flows on the lines.

DG units, being scalable, can be built to meet immediate needs and later scaled upwards in capacity to meet future demand growth. This is in contrast to central generation plants which are designed to accommodate future, foreseeable demand and are consequently built on a much larger scale. Scalability allows DG units to reduce their capital and operations costs; large amounts of capital are not tied up in large investments or in their support infrastructure. Savings can also be achieved since infrastructure upgrades (such as feeder capacity expansions) can be deferred or altogether eliminated. From a customer point of view, savings may be accrued from the additional choice and flexibility that DGs allow with regard to energy purchases.

DG also has the potential to introduce environmental benefits by reducing emissions – although this depends on the DG technology. However, with the high costs associated with technologies with low emissions, the environmental benefits may not be realized until investors are convinced through monetary incentives/disincentives, from governmental policies, that these are worthwhile investments.

Typically, power transmission over long distances result in voltage drops of significant magnitude, in the absence of any correction. DG systems can assist in improving voltage regulation by injecting both real and reactive power close to the load, thus reducing the transmission losses.

Alleviating voltage dips (sags) and the improvement in load-side voltage profile are two contributions to voltage support by DG units. Voltage dips are momentary decreases in voltage (0.1 - 0.9 pu) over a short period of time (1/2 cycle to 1 minute). These dips are often caused by sudden increase in load (*e.g.* from starting machinery, faults) and can result in voltage sensitive equipment failing to operate properly. Two methods of mitigating voltage dips (both balanced and unbalanced) using DG units are proposed in [15].

DG units make positive contributions to the reliability and security of distribution systems (where 94% of all faults occur) from the perspective of loads [16], [13]. In some industries, the value of load lost can be extremely high, almost $40,000/hour in wireless communication industry and $6.4 M/hour for brokerage operations [16]. Availability of DG units for back-up power can result in significant avoided costs to the customer. In [17], Goel and Billington quantify the value of reliability by amalgamating reliability indices with the customer cost of interruption for different industries using three different methods. By quantifying the values, distribution system planners can include reliability cost in the optimization models.

Despite all the advantages of DG, the addition of DG units can also have negative impacts to the distribution system, as discussed in [18]. These include service interruptions if DG units mask load growth (and subsequently inhibits proper planning) to the point that its loss would result in inadequate supply. Other complex technical problems introduced by DG include protection coordination, voltage regulation and flicker, and harmonic problems [19].

1.3.5 Planning and Expansion

The proper planning of distribution systems (especially those with DG) must take into account the interests of all stakeholders, who must first be identified. One possible arrangement has the LDC owning as well as operating the DG unit at any given location. Other arrangements include either a customer or SPP owning and operating DG within the LDC's distribution system. Other stakeholders, those that have an interest in DG or their effects, not necessarily monetary, include federal, provincial, and municipal governments, the public, environmentalists, etc.

One option for the evaluation of possible DG investments is from a purely monetary point of view. In [20], a method is proposed for determining the break-even price for utility investments in DG under uncertainty, considering capital, energy, and environmental costs. Possible methods of measuring the financial impact (from deferred investment, reduced losses, etc) of DG on distribution systems, from utility or business point of view, are discussed in [21].

In [22], three major factors – economic, engineering, and financial – are identified, that have been generally used for the evaluation and planning of DG. Each of these identified factors comprise multiple parameters, as given in Table 1.2.

In distribution systems planning there exists a significant dichotomy between research-oriented methods and the experience-based methods put into practice by industry. The current practice of distribution system designers is to rely on their

Table 1.2: Factors considered in DG Planning [22]

Economic	Engineering	Financial
General Economics	Generator Characteristics	Regulated Revenues
Regional/Utility Characteristics	Power Flows	Capital Expenditure
Generator Revenue	Faults	Operational Expenditure
Generation Capital and Operating Costs	Power Quality and Transients	
Generator Operating Characteristics	Security and Reliability	

wealth of experience while taking a heuristic approach to the design. However, these approaches contain some deficiencies as outlined in [3]. These include inaccuracies in data, suboptimal generation mixes, plans rarely resulting in least cost operation and investment, neglect of consumer reaction from the planning process, inability to deal with uncertainty, and failure to account for, analyze, and use private investors in planning.

1.3.6 Environment

With climate change agreements such as the Kyoto Protocol, environmental emissions (air pollution) has been a topical issue and the focus of attention amongst politicians and regulators. There are three main components to air pollution from electricity generation: nitrogen oxide (NO_x), carbon dioxide (CO_2), and sulphur dioxide (SO_2). NO_x and SO_2 emissions are responsible for bad air quality (smog) and acid rain, giving rise to respiratory problems and bad aesthetics. NO_x is also a greenhouse gas, which, along with CO_2, may be responsible for climate change (raising of the earth's temperature).

In the United States, electrical utilities account for 22% of all NO_x emissions and 38% of all CO_2 emissions, the single largest source [23], [24]. Similarly, SO_2 emissions are from the use of high sulphur coal for power generation – which is prevalent in the US and Ontario. Environmentally friendly DG units, such as wind turbines and solar-PV, can be used to displace polluting bulk generation sources, thus resulting in a net reduction in emissions.

1.4 Deregulation

Beginning in the late seventies in Chile and early eighties in England, the drive towards deregulation of the electric power supply industry has transformed the way power systems are operated now, all over the world. In Canada, the move to deregulation was adopted first by Alberta in 1995, followed (partially) by Ontario in 2002. This shift towards deregulation was often driven by idealogical goals; governments pushing for deregulation generally believed in the privatization of public assets.

It was believed by proponents of deregulation that an open market would result in economic gains benefiting both investors and consumers. It was thought that investors, under deregulation, could get higher rates of return and consumers would pay less for energy, enabled by increased system efficiencies from competition. Furthermore, deregulation could bring investment into the electricity industry, lessening costs to the government. In retrospect the results have been mixed; in some cases, the exact opposite has occurred.

To accomplish this process of deregulation, financial, organizational, and operational integration between the elements of the bulk electric power system (generation, transmission, and distribution) was removed. Generation companies were allowed to compete for production of energy or set bilateral contracts directly with brokers or consumers. Transmission companies, because of their very nature, remained a monopoly; however, their relationships with other units were severed in order to maintain a fair market. Similarly, LDCs were separated from generation and transmission operators; customers were no longer required to buy energy from them.

Different goals and objectives have evolved with the change in stakeholders (*e.g.* customers, financiers, etc) that deregulation brings. For example, the erstwhile objective of overall system efficiency and seamless integration has given way to individual efficiency and maximization of profits (or minimization of costs, for generators and customers respectively), given minimum required reliability levels. Similarly, tariffs now reflect actual real-time costs as opposed to being averaged out among users [25]. Some also suggest that power quality and reliability, once considered unassailable, and the option to shed load are fair play and can be charged for [25].

The structure of the deregulated market in any given jurisdiction, including the level of market intervention and regulatory pressures, depends on the government and its regulators. For example, despite being a competitive market, large energy producers may act as a monopoly (a by-product of the previously regulated era) or perhaps energy prices may be fixed for consumers due to government pressure; both these situations exist in Ontario. The drive towards deregulation is not a single process but may involve multiple steps.

1.4.1 Implementation

Talati *et al.* [26] discussed a two-stage process of deregulation – wholesale competition, followed by retail competition. The electric supply options available to retail

Table 1.3: Electricity Supply Options in Power Systems

Retail Purchase Option	System Structure		
	Vertically Integrated	Wholesale Competition	Retail Competition
Purchase from LDC (fixed tariff)	Yes	Yes	Yes
Self-generation/cogeneration	Yes	Yes	Yes
DSM	Yes	Yes	Yes
Purchase from LDC (real-time pricing)		Yes	Yes
Purchase from independent system operator (ISO) or pool			Yes
Purchase from retailer			Yes
Bilateral contract with supplier			Yes
Load aggregation			Yes
Other financial instruments			Yes
Wheeling	Yes	Yes	Yes

customers prior to deregulation (in vertically integrated system structure) and in the case of wholesale and retail competition are outlined in Table 1.3.

In wholesale competition structures, retail (end-use) customers would be required to buy energy directly from their affiliated distribution company (i.e. no retail competition - the distribution company would retain their monopoly). Choice would only be available to the distribution companies and large industrial customers who could either bid for energy from the market operator or purchase energy directly through bilateral contracts from power producers.

Retail competition on the other hand, provides the most options for end-users, allowing retail customers to buy power through bilateral contracts, the market, or through retailers (although the option to buy through distribution companies would still exist). Many other supply management options also exist, as outlined in Table 1.3.

The 'purchase from local utility' option has traditionally been the default option in the vertically integrated environment, where customers would purchase power from their local utility. Self-generation or cogeneration is an option limited to those customers having their own generation units (*e.g.* CHP units). DSM, an option under DER, refers to load management strategies, sometimes with cost subsidies by the utility. Another option introduced by wholesale markets allows consumers to buy energy from local utilities based on time of use rates, or real-time prices correlating to the varying prices that the utilities pay.

Retail competition introduces additional options, including the purchase of power from the pool, through a retailer, or directly from generation companies. A collection of loads may also act together for their best interest (known as load aggregation) to better their market position (and secure better prices). Additionally, retail consumers may choose to buy their ancillary services unbundled from their energy costs or participate in hedging or other financial instruments.

1.4.2 Impact on Distribution Systems

The impact of deregulation at the wholesale level is well researched, whereas literature on the impact that deregulation may have on distribution systems is sparse. The impact of deregulation on distribution systems may arise through retail trading, specifically though increased participation by SPPs with DG units. Traditionally, most distribution systems are radially configured, with power transversing from the root node to feeder ends. Higher penetration levels of DG may cause these traditional power flows to change (reverse direction), since with generation from DG units, power may be injected at any point on the feeder. New planning techniques must ensure that feeders can accommodate changes in load configuration. Literature in this area has been reviewed in Chapter 2.

With the implementation of retailing and DG, network reconfiguration and distribution automation is expected to become more prevalent, as this would permit greater flexibility and control of the distribution system [27]. To permit greater flexibility, protection and control devices must be configured or upgraded to accommodate network reconfiguration, including the accommodation of reverse power flows. Appropriate policies should be put in place to allow operation of the distribution system in islanded mode (isolation of a small portion of the grid while maintaining electric supply within) [28]; consequently, additional protection must also address equipment and worker safety and be able to provide appropriate protection during such operation.

Other possible changes resulting from deregulation [25] include increased importance on demands from customers for power quality and reliability, possibly leading to performance based rates. It should also be kept in mind that competition and the drive for profit may result in higher equipment loading, and consequently increased equipment failure [27].

1.5 Research Motivation and Goals

A number of factors have been driving changes to distribution systems, subsequently creating a need to examine different aspects of its planning. Advances in DG technology has made its penetration into distribution systems feasible for both LDCs and SPPs. Furthermore, deregulation has opened up distribution systems to SPPs willing to invest in DG. Also, renewable and clean energy DG technologies are seen as having benefits to the environment, and thus policies are being enacted to encourage their investment in distribution systems.

Investment in DG, and its subsequent implementation within the distribution system, requires the involvement of three major stakeholders: the LDC, SPPs, and regulators. It is within the LDC's system that DG units are installed and hence it must plan its infrastructure so as to accommodate DG units considering the options of either installing its own DG or connecting SPP-DG units. SPPs are potential investors of DG; anything that may impact their ability to install DG units, or their rate of return, will be of interest to it. Government regulators (which, by extension, encompasses consumers) are also keenly involved in DG investments, as they play key roles in meeting market deregulation and/or environmental emission reduction goals.

LDCs are required to adhere to regulations set by regulatory agencies, and thus may have limited control over DG investments. As stated earlier, LDCs may be able to invest in their own DG and/or be forced to connect SPP-DG units. SPPs investments, on the other hand, may fall under the jurisdiction of both the governmental regulators and LDCs. Regulators will determine whether they are permitted to participate in electricity generation, and the rules and incentives under which they participate. SPPs may also be required to work with LDCs to reach mutually beneficial solutions to DG investment problems.

The design and planning of distribution systems focused on DG unit investment is a complex problem, especially when considering that the major stakeholders have different technical and economic directives and goals. The objective of this research is to broadly analyze some aspects of this design and planning problem from the viewpoint of the different stakeholders.

The goals of this research, realizing this multifaceted approach, are described as follows:

- The first goal is to examine the LDC's long term distribution system planning problem taking into account DG unit options, and to propose a comprehensive framework for solving the problem that will assist in understanding the role of DG and the impact it has on the distribution system.
  - The framework incorporates traditional planning elements, including the optimal sizing, placement, and upgrading of feeders and substations.
  - DG units, including those invested in by the LDC and forced onto the LDC by SPPs, are included as possible options to address the complex issues arising from the deregulated environment.
  - The impact of external factors, such as taxes, regulatory policy, market prices, and environmental factors, should be able to be determined from the framework.
- Since it is realized that LDCs may have little control in the adoption and implementation of DG, the second goal of this research is to examine policy instruments that may be employed by government regulators and the long term impact that the policies may have on the distribution system.
  - As part of the analysis, a simplified distribution system model is considered, based on the comprehensive framework proposed earlier and geared towards extensive case study and scenario analysis.

  - These case studies examine both deregulated and vertically-integrated distribution systems, in light of DG investment incentives and emissions reduction mechanisms.
  - The resultant impacts on DG investments, energy dispatch/purchase decisions, and emissions from the various policies are studied.
- The final goal is to propose a method for coordinating SPP-DG proposals should policy instruments enacted by regulatory agencies become effective in encouraging investment in DG beyond the means of the LDC to implement them.
  - The proposed method is able to help regulators and LDCs realize the full potential of DG.
  - The method is fair and transparent to both the LDC and SPPs.

1.6 Outline of Thesis

A review of literature on research pertaining to the topics of this thesis is presented in Chapter 2, covering the following areas: distribution system planning, planning in deregulation, and DG policies and impacts.

Chapter 3 presents a two-stage, hierarchical dynamic optimization framework to address the planning and energy scheduling problem in power distribution systems. The framework is geared towards solving large, long-term distribution system planning problems, and can take into consideration complex issues arising from deregulation and environmental policies. It is applied to the planning problem of a 32-bus radial distribution system, and the results from the application of four different policy scenarios are developed and discussed.

Chapter 4 examines the policies that can be used to encourage DG investment and incorporates them into a mathematical model. This model is then used to create scenarios for examining the economic and environmental supply-side effects of policies applicable to distribution systems over a ten year period. The policies analyzed include a combination of feed-in-tariffs, CO_2 tax, and cap-and-trade schemes. The results are discussed in the context of the Ontario market and its Standard Offer Program, implemented on a 32-bus radial distribution system.

Chapter 5 proposes a systematic approach for the coordination and selection of DG unit investment proposals submitted by multiple, competing, SPPs. It uses a feedback mechanism between the LDC and SPPs to achieve maximum investor participation while complying with the technical operational limits of the LDC. The concept of commons and domains is used to identify the largest transgressors to system function, and forms the basis for revisions to SPPs proposals. This application of the scheme, and the resultant effects, is demonstrated on a 32-bus radial distribution system.

Finally, Chapter 6 concludes with a summary of the research in this thesis, contributions, lessons learned, and directions for future research.

Chapter 2

Literature Review

2.1 Introduction

Operations research (OR) techniques were first applied to distribution system design and planning problems in the mid-1970's. Initial research focused on 'traditional' planning problems – the placement of substations and routing of feeders to minimize costs and losses to the LDC. Since then, the approaches taken to optimal distribution system design and planning have grown more comprehensive and sophisticated, driven by both changes in the tools available to researchers and changes to distribution systems themselves. Advances in OR methods and computational abilities have permitted detailed modelling of system elements, allowing, for example, modelling of non-linear representations of loads and power flows. Faster computers have also allowed for superior solutions, and risk and uncertainty issues can now be addressed.

In addition to new tools, research has been driven by the evolution of distribution systems due to changes in technology and policy. One of the most significant changes has come through the introduction and widespread acceptance of DG: small generation resources connected to the distribution system. Investment in DG may either be made by small power producers or the LDC, with distinct planning requirements for each. Major policy changes have come from deregulation of the power industry and increased environmental awareness. With the onset of deregulation, the planning problems have become more market-oriented, capable of considering multiple resources of energy rather than just utility resources. Finally, environmental issues have driven policy changes, resulting in governments encouraging clean and renewable energy integration into distribution system planning.

This literature review is divided into three thematic areas. The first section reviews planning problems related to traditional distribution system planning (including uncertainty and reliability issues and solution algorithms). Next, a review of literature on distribution planning in the context of deregulation, where DG plays an important role, is presented. Finally, a review of research investigating the impact of policies influencing investment in DG resources in distribution systems is presented.

2.2 Distribution System Planning

2.2.1 Traditional Distribution System Planning

This section makes a modest attempt to discuss some of the approaches adopted and reported in the literature addressing the traditional distribution system planning problem. A number of models proposed and published in the literature consider the traditional problem of power distribution system design: the placement of substations and feeders in the primary system to meet non-uniform loads. These models, while sharing certain commonalities, approach the problem in a number of ways. This literature review discusses models that can be used for long (or horizon) range planning, with some applicable to short range planning. The models are classified as single-stage (single build period) or multi-stage (continuous construction over multiple years), with the objective function and/or constraints forming either linear programming (LP) or non-linear programming (NLP) models. Earlier models tended to be simplistic owing to the lack of powerful solution algorithms or computational power available.

Delson and Shahidehpour discussed the role of linear programming (including Bender's decomposition) and dynamic programming techniques to power system planning in [29]. They recommended that the linear, master program should be responsible for capital investment decisions, and the subproblem, needing only to be convex, should be responsible for production costing. Although this work was intended for evaluating large generator investments, it can be applied to distribution systems in deregulated environment that mimic the capital and production costing of their larger cousins.

Khator and Leung [30] discussed the general issues of power distribution system planning with an overview of some relevant models and prior work. They classified distribution planning problems into two categories: planning under normal conditions and planning considering contingencies. In their work, the authors also justified the superiority of multi-period (dynamic) models over single-period models (and their variations) in achieving optimal solutions.

The integration of a Geographic Information System (GIS) into distribution planning is discussed by Yeh *et al.*, in [31]. The concepts of long-range and short-range planning are introduced and the co-ordination between them is discussed. In essence, long-range planning sets a direction for short range planning exercises to follow. In the long range (10 years), location of installations are determined, while in the short range (3 years) size and the year of installation are finalized (from their initial solutions obtained in the long-range plan).

Holt and Crawford [32] introduced one of the first distribution system planning models using OR techniques: a single-stage LP. The objective function minimizes the load along a feeder multiplied by the fixed per unit (MW) cost of the feeder. Feeder paths, from substation to load, are determined using Dijkstra's minimum path algorithm, and Ford and Fulkerson's transportation algorithm are used to determine power flows. This formulation ignored the ability of a single feeder to feed multiple loads along its path.

Wall *et al.* [33] used a transshipment (a variation of network flows) formulation to model power flows, thereby avoiding the problems of [32]. They also used a single period and linear model, minimizing either $load \times distance$, $load \times resistance$ ($losses$), or $load \times cost$. The authors advanced their previous model, in [34], by including the substation siting aspects to arrive at a mixed integer linear program (MILP).

A comprehensive review of models created before 1986, that addressed the traditional distribution planning problem, was presented by Gönen *et al.*, in [35]. This review compared the mathematical formulation of models and their treatment of element costs and characteristics. The authors further proposed a MILP model [36] to solve the multi-stage planning and expansion of existing infrastructure problem. A major feature of the work is the use of linear approximations to the cost of investments and energy losses in the objective function, along with its ability to solve both feeder and substation expansion problems simultaneously. A review is provided in [37] to compare existing models from a computational perspective, *e.g.* the amount of resources, data required.

Whereas in [35] and [36] a completely dynamic model was presented, the authors in [38] presented a pseudodynamic model which otherwise retained the same characteristics of the prior dynamic model. In this pseudodynamic model, the final design solution at the horizon year is achieved first, followed by incrementing from the first year to the *horizon year minus one* to meet demand in each year, incorporating elements of final design solution until it is fulfilled.

Most models, up to this point, used linear cost terms. Ponnavaikki *et al.*, in [39], proposed using a quadratic representation of costs from feeder losses in combination with fixed capital cost terms. To solve the model the authors devised a two stage method: the first stage is used to fix substation locations; the second stage is used to find the optimal set of feeder branch elements.

Blanchard *et al.*, in [40], modelled the traditional distribution system planning problem using non-linear cost terms (but kept the linear transshipment power flows) as a mixed integer non-linear program (MINLP). The authors then proposed a 5-phase computational method to solve the problem using linearized approximations of the cost function while removing radiality constraints. Only the the first 2 phases were discussed in this paper.

To address the complexity of discrete non-linear problems, Temraz and Salama, in [41], presented a cost objective function that substitutes the binary variables

Objective Function:

- Discounted cost of new feeders and/or existing feeder capacity upgrades
- Discounted cost of new substations and/or substation capacity upgrades
- Discounted cost of losses

Subject to:

- Linear network flows (peak load for each year) for nodal demand-supply balance
- Line power flow constrained by feeder and substation capacity, considering peak demand state
- Feeder and substation capacity constrained by existing and new builds
- Feeder and substation new builds and upgrades constrained by maximum capacity
- Voltage drop constraints

Decision Variables:

- Feeder: siting, (new) capacity, year of installation
- Substation: siting, (new) capacity, year of installation

Figure 2.1: Generic Traditional Distribution System Planning Model

usually seen in MILP models with an exponential term. Additionally, this model uses ac power flows and has an ability to minimize costs through element upgrades, rather than just the installation of entirely new elements.

The typical distribution system planning model is represented in Figure 2.1. This model forms the basis for most modern research in distribution system planning.

Fletcher and Strunz, in [42] (and applied subsequently in [43]), formulated a primary and secondary distribution system planning model, with emphasis on substation and feeder numbering, selection of appropriate voltage level, and sizing of feeder length and capacity. Unlike the models represented in Fig. 2.1, this work uses circular topologies to represent uniform loads served by individual substations, assuming that substations are placed in the centre of feeders which radiate outwards.

2.2.2 Distribution System Planning in Deregulation

It has been observed that with the advent of deregulation, traditional distribution planning models have undergone a paradigm change to address the various issues arising therefrom. This section discusses various proposals for optimal distribution planning in such deregulated environments.

A number of developments in the electric power industry have rendered the erstwhile, traditional long-range planning techniques obsolete in many jurisdictions which have undergone restructuring. Deregulation of the electric utilities has required that not only capital costs and losses be considered in the objective function, as before, but also energy costs. Advancement in DG technology has also made generation within distribution systems more widely available, forcing LDCs to consider placing their own DG units or integrate SPP (or customer) owned DG units. Newer models of distribution system planning introduced alternatives to the traditional methods by adding interties and utility DG's as possible options to meet demand. However, initial research focused solely on the placement of DG units and not planning of the distribution system as a whole.

Chowdhury *et al.*, in [44], presented a DG investment model based on such a concept using various reliability indices in order to determine the optimal DG locations and sizes. Their studies revealed that, although DG investments are more expensive than distribution system upgrades, these can be cost effective in combination with capital deferral credit.

In [45], Bender's decomposition is used to optimally site distributed resources within the transmission system while considering the stochastic nature of generator production. Three separate modules are used: one for the modelling of the bulk generation and transmission system operations, another for the planning of transmission and generation assets, and the third for the placement of distributed resources.

While the previous work, [45], proposed a method for placing distributed resources considering uncertainty in generation, Haghifam *et al.*, in [46], proposed a method for placing DG units considering uncertainty in load. Using a multi-objective function, DG units are sited with the objective of minimizing costs, technical risks (from the overloading of substations and feeders or exceeding voltage limits), and economic risks (from the uncertainties in electricity price). The final solution is a set of Pareto-optimal options from which the planner could choose the most suitable one.

In contrast to previous models using constant load models, Singh *et al.* [47] examined the use of different load models, finding that the choice of models has a significant impact on the optimal planning of DG. Using voltage dependent load modelling, it is shown that system reactive power demand increases, negating the effect of decreased losses. The foundations established in [47] were used in [48] to the develop a multi-objective model for the siting and sizing of a single DG unit.

Whereas the aforementioned research concentrated solely on the planning of DG, El-Khattam *et al.* introduced two methods for the planning of DG units and the host distribution system, from the point of view of the LDC. The first method [49] is a (step-by-step) heuristic approach to DG investment planning that uses an optimization model at each step. In meeting demand requirements the LDC has three options: purchase power from the grid, install DG capacity, or shed load. The mathematical objective function included investment and operating costs, energy import costs, unserved power costs, and losses. In essence, the algorithm examined the benefit/cost ratio of each possible DG unit option and selects those with a net benefit. However, this model does not incorporate the 'planning over time' aspect of distribution planning – which usually span a horizon of 5-15 years.

The second model [50] uses a single optimization model to avoid the use of the heuristics. Using the same concepts, but with binary variables, the problem attempts to minimize the cost of supplying the demand by either purchasing power from the main grid, purchasing power from interties, or investing in DG. The planner is allowed to upgrade substations and feeder capacity.

A generic market-oriented planning model is presented in Figure 2.2. Note that none of the previously discussed research incorporates SPP-owned DG where the LDC has little or no say in the commission or operation of DG units.

2.2.3 Inclusion of Uncertainty and Reliability Issues

Some researchers explicitly addressed the issues of uncertainty and reliability in distribution system planning. However, generalized approaches to finding optimal solutions considering uncertainty can also be found in OR journals without specific application to distribution planning.

The majority of models discussed in this chapter are deterministic, in which a single plan is built using 'best estimates' for future data. Gorenstin *et al.* [51] introduced multiple methods of distribution planning with uncertainty which included scenario based planning and planning using stochastic optimization. In the scenario planning approach [51], solutions are conceived for all possible scenarios; afterwards, a single plan is chosen that best fits all solutions. A single best fit plan, it was stated, is difficult to find. In the stochastic optimization approach, multiple scenarios are incorporated into a single model, so that a best fit plan can be derived. This formulation requires that some decision variables be set, such as investments, before the final scenario is known (and uncertainties resolved). The objective function can either be the minimization of expected costs, or minimizing the maximum regret (which is advocated in [52]).

In [53], a method is devised for the optimal selection of candidate substation sites in a given area using probability distributions. Similar to [42], this approach takes a topological approach to placement of substations, as opposed to explicitly considering feeder paths and routing. Outage and switching equipment costs are included in the basic objective function in [54] to account for reliability (switching) issues in planning, whereas in [55] a comprehensive contingency analysis of multiple system elements is incorporated within the planning problem.

Objective Function (various combinations of):

- Discounted cost of new feeders and/or existing feeder capacity upgrades
- Discounted cost of new substations and/or substation capacity upgrades
- Discounted cost of new intertie and/or existing intertie capacity upgrades
- Discounted cost of new DG and/or DG capacity upgrades
- Discounted cost of energy from grid purchase
- Discounted cost of energy from intertie purchase
- Discounted cost of energy from DG

Subject to:

- Network flows (linear or ac power flow) for nodal demand-supply balance, including losses
- Line power flow constrained by feeder, substation, intertie, and DG capacity
- Feeder, substation, intertie, and DG capacity constrained by existing and new builds
- Feeder, substation, intertie, and DG new builds and upgrades constrained by maximum capacity
- Voltage drop constraints

Decision Variables:

- Feeder: siting, (new) capacity, year of installation
- Substation, intertie, and utility DG: siting, (new) capacity, year of installation
- Grid and intertie energy purchase from market or other LDCs
- Utility DG: energy production schedule

Figure 2.2: Generic Distribution System Planning Model for a Deregulated Environment

2.2.4 Solution Algorithms

As computational power and OR algorithms improved, the complexity of the distribution system planning models also became more complex and difficult to solve. By the early 1990's, research literature focusing on application of OR algorithms to solve the planning problem efficiently and optimally began to appear.

Initial research dwelt on solving single period or simplified multi-period planning problems. Aoki *et al.* [56] proposed solving a single period MILP model by combining pivoting methods within the simplex tableau with the branch exchange technique. This technique was further advanced in [57] to include simplified multi-period planning, with individual solutions found for each year and integrated though forward and backward paths. In [58] a multi-stage branch exchange technique (rather than a combination of single stages as in [57]) is used to solve the same problem and in [59], branch and bound techniques in combination with heuristics is used to obtain a radial distribution plan solution for the MINLP single-stage problem. Branch exchange is also used in [60] to determine, in two stages, the optimal substation service areas and network configuration.

Pseudodynamic approaches were also used by researchers to resolve the computational burden involved in finding optimal solutions to the distribution planning problem. Quintana *et al.* [61] proposed a two-stage technique to solve a NLP model similar to that in [41], in which the first stage is responsible for load forecasting and the second uses a pseudodynamic algorithm to find the multi-year solution. A pseudodynamic solution was proposed, in [62], for the traditional planning problem using genetic algorithms (GA); it was shown that pseudodynamic approaches are generally better at finding optimal solutions than non-dynamic approaches.

The use of GA to solve difficult distribution planning problems is commonly cited in the literature. In [63], GA is used to solve dynamic multi-stage planning problems with favourable results. Using GA in combination with other techniques and heuristics to improve planning solutions is explored in [64]. Adaptations of GA to the distribution planning problem are further advanced in [65]. In [66], the authors presented a two-stage method using GA. The first stage optimally sites and sizes medium-voltage substations, which in turn is used as input to the second stage to optimally site and size high-voltage substations and determine medium voltage feeder routing.

Other, less common solution algorithms have been cited in literature. A steepest descent approach is first used in [67] for generating the initial plan for a new, radially-configured distribution system. Simulated annealing techniques are then applied to find the optimal solution, with the object of reducing costs associated with feeder routing. The potential role of knowledge based systems in designing rural distribution systems is reviewed in [68]. A directed graph formulation approach is used in [69] to solve a multi-stage planning problem.

2.3 DG Policies and Impacts

The penetration of DG into distribution systems has been fostered by technological progress coupled with widespread regulatory acceptance and incentive programs. Deregulation of the power industry has opened the sector to increased investments in DG from private parties. The push from governments and consumers to find environmentally sustainable resources of energy is further driving the penetration of those DG that are seen as clean or renewable, and are often the subject of additional incentives encouraging investment.

This section first reviews policy instruments that have been commonly employed by governments and their regulatory agencies and their ability to reach their intended goals. The second part of this section reviews literature dealing with measuring the impact of DG, with the goal of assessing charges or credits to participating entities.

2.3.1 Policy Instruments

Three policy instruments, tender/bidding, tradable green certificate (TGC) or renewable energy certificate (REC) trading, and feed-in tariffs (FITs), are commonly cited as being employed by regulators to achieve goals of meeting electricity demand with clean or renewable energy resources [70], [71].

Under a tender/bidding system, the regulator establishes a quota for energy to be supplied by renewable generation. Potential investors are then invited to submit proposals/bids, in $/MWh, for renewable energy contracts to meet this demand. Proposals are then ordered by cost, from the lowest to highest, and contracts awarded until the quota is met; winners are paid as-bid. The United Kingdom's Non-Fossil Fuel Obligation (NFFO) is an example of a tender/bidding system.

In a TGC/REC system, distributors, retailers, and/or customers must meet a percentage of their energy consumption, as set by regulators, from clean or renewable energy resources. This is achieved by attaining the requisite amount of TGCs/RECs which can be either earned through self-generation or purchased from a renewables market. TGCs/RECs are awarded to qualifying generators, who may then retain them, trade via a renewables market, or sell to other operators. This system is employed nationally in Australia and Sweden (among others) [72], [73].

Jurisdictions offering FITs give additional incentives to qualifying generators by paying for energy at prices greater than the market rate. FITs may be differentiated based on technology or time-of-use and may be guaranteed, via contract, over long periods, *e.g.* 20 years. In [74], an extensive analysis of FIT implementation in Spain was conducted, examining its development and what made it effective. Amongst the conclusions reached is that, to be effective, FIT programs should be perceived as stable by participants and thus not undergo significant policy shifts or frequent program changes. FITs are offered in Ontario, Canada, as well as many European countries [75].

Significant research has been carried out to analyze these three policy instruments and their ability to achieve their stated goals, with FIT mechanisms usually the preferred option. In [70], FITs are favoured from amongst the three policy instruments for achieving the penetration targets set for renewable energy technologies. It is recognized that, while controlling the program cost of FITs is difficult and may not stimulate drops in technology prices, FITs are effective because of the stability and security they offer to potential investors.

In [76], the Renewables Portfolio Standard (RPS) (a variation of the TGC/REC mechanism) was compared to FIT programs using empirical evidence from three countries: Denmark, Germany, and the UK. After examining penetration, contribution to carbon reduction, and employment effects of the programs, it was concluded that FITs are best at achieving penetration and employment targets (with mixed results on carbon reduction). Although this study is based only on a small sample size of three countries, its conclusion is reaffirmed in [77], where it is shown that TGC/REC mechanisms encourage investment in incumbent technologies rather than emerging technologies, therefore ending up being costlier in the long-run. In a comparison of FIT programs and the EU's proposed TGC system, [75], it is again recommended that FITs be pursued, because of their speed in achieving investment goals and the level playing field they present to the industry. Despite the purported superiority of FITs established in the research literature, both FITs and TGC/REC are favoured by governments worldwide.

In addition to comparisons of different FIT mechanisms, some works have analyzed the implementation of FIT mechanisms. For example, an examination of different policy instruments in EU countries to encourage wind investments reported that the most successful have been in jurisdictions offering a combination of FITs and subsidies [78]. In [79], FITs, based on the old Danish 'triple tariff' (time-of-use) system, are recommended to encourage CHP with district heating. In contrast to the trend of offering FITs to encourage renewable energy, [80] recommended the slashing of FITs for solar energy, claiming that it does not reduce emissions nor increase employment.

In order to find the best ways to promote renewable energy and energy efficiency, Sovacool, in [81], conducted extensive interviews amongst many different stakeholders for their opinion. In addition to favouring FITs, as discussed above, participants were found to favour elimination of subsidies for established technologies (such as those using fossil fuels), pricing electricity accurately (*e.g.* eliminating price caps or declining-block pricing in favour of time-of-use schemes), and education.

Econometric modelling, in [82], of data from the United States is used to evaluate the impact of various policies on DG implementation within distribution systems, distinguishing between private and public-utility distribution systems and consumer and utility-owned DG. It is observed that private-utilities typically have higher distribution costs and lower reliability than public-utilities, and thus are more willing to adopt DG because of the improvements they can bring. Furthermore explaining the difference in adoption rates, it was found that policies within the U.S. mandating DG adoption are more geared towards private-utilities; public utilities are often exempted.

2.3.2 Quantifying the Impact of DG

FITs and other policy instruments discussed above are focused on encouraging investment in environmentally friendly technology such as CHP, solar-PV, etc. However, these policies do not explicitly take into account the effects they will have on the distribution system from DG investments. There is a need for devising additional mechanisms for such DG investment to suit the individual distribution systems in light of FITs and other policy instruments.

In [83], the authors presented a single period model for distribution system planning. This model, which minimizes capital, loss, and unserved energy costs, is used for finding the annualized fixed charge rate (AFCR), assessed to loads, under two conditions: with and without the DG units. The AFCRs of the two states (with and without DG) are compared to determine the annual avoided charge rate (AACR) of DG (which may be positive or negative).

Gil *et al.*, in [84], proposed simple mathematical models for quantifying the benefits of DG units to LDCs and the power system operator/society. Modelled LDC benefits include investment deferrals, avoided electricity purchases, and loss reduction. The authors proposed that utilities offer paybacks (benefits minus connection costs) to private-DG or build their own DG units.

To the best of this author's knowledge, there has been no work so far on devising DG investment coordination mechanisms where the LDC has no stake in the investments and only provides the network service.

2.4 Concluding Remarks

This chapter makes a modest attempt to present a review of literature on distribution system planning. In the first section a review of methods for solving the distribution system planning problem is presented. Thereafter, an extensive review of policies encouraging investments in environmentally friendly distributed generation technologies is presented. Literature justifying the use of FITs are presented; it has been observed that FITs are widely accepted and are superior to other green-energy policy instruments. However, although FITs affect placement of DG and thus distribution systems, there has been no work on devising DG investment coordination mechanisms where the LDC has no stake in the investments and only provides the network service.

Chapter 3

Distribution System Planning with DG in a Deregulated Environment[1]

3.1 Introduction

As described in Chapters 1 and 2, deregulation of the power industry and consequent penetration of DG has forced a paradigm shift in distribution system design and planning. In this new environment, both LDCs and SPPs play a role in distribution system investment; the minimization of energy costs is now important and must be considered alongside alternative supply options such as DG.

This chapter introduces a framework for the comprehensive planning of the distribution system, by the LDC, relevant in today's environment. The proposed distribution system planning framework presented

a) incorporates various energy supply options for LDCs such as DGs and interties, and determines the near-optimal sizing, placement and upgrade plans for feeders and substations,
b) addresses the complex issues arising from the deregulated environment, such as the availability of a variety of energy sources at different costs (including SPP investments in DG that are not controlled by the LDC),
c) examines the impact of external factors, such as taxes, regulatory policy, market prices, and environmental considerations, on LDC planning.

[1] The work presented in this chapter has been accepted for publication and will appear in S. Wong, K. Bhattacharya, and J.D. Fuller, "Electric power distribution system design and planning in a deregulated environment," *IET Generation, Transmission, and Distribution*, In Press. An earlier version of this work has been presented and appears in S. Wong, K. Bhattacharya and J.D. Fuller, "Comprehensive framework for long-term distribution system planning," *Proc. IEEE PES Annual General Meeting*, Tampa, USA, 2007.

The gap between traditional OR-based planning techniques and DG siting methodology are addressed by this framework. It is very detailed and improves upon previous research, carrying a number of features; the framework

a) is fully dynamic; commissioning of elements vary by size and year,
b) optimizes feeder layout; layout may be radial or networked,
c) permits both LDC and SPP-DG unit, where the latter includes near-optimal siting (if possible),
d) models various types of DG technology, taking into account varying costs and capacity factors,
e) accommodates multiple load demand blocks: base, intermediate, and peak, and
f) can be used for large systems, incorporating a two-stage process to improve solvability.

In Section 3.2, an overview of the proposed distribution system planning framework is presented. This is followed by the mathematical modelling of the associated optimization models in Sections 3.3 and 3.4. While this modelling (Sections 3.3 and 3.4) forms the heart of this work, the mathematics is very detailed. In Sections 3.5 and 3.6, the detailed plan studies and results considering a 32-bus radial distribution system implemented under multiple policy sets are presented.

3.2 Proposed Distribution Planning Framework

Ideally, one comprehensive MINLP model would suffice to solve the distribution system planning problem, and was initially considered. However, such a formulation was computationally very intensive and often failed to arrive at a feasible and nearly optimal solution due to complexities of the non-linearities and the presence of binary variables in the model.

A two-level hierarchical scheme of inter-related models is therefore proposed that imitates the decision making process of the real-world planning: a Siting-cum-Period Planning Model (SPPM) and a Capacity-cum-Production Planning Model (CPPM). The SPPM is a MILP model that determines the near-optimal period and location of resource installation over the planning horizon of 10 years, and can be used ahead-of-time to obtain land-rights, permits, etc. The CPPM is a NLP model that determines the near-optimal unit capacities and production/contract schedules and makes any necessary changes to the SPPM's recommendations.

The proposed distribution system planning scheme (Fig. 3.1), is executed in two stages – the SPPM is solved first, after which its results are fed into the CPPM to arrive at a comprehensive plan. Information transferred to the CPPM includes a set of final and firm decisions on siting and period of commissioning of infrastructure investments determined in the SPPM. This alleviates the need for binary variables in the CPPM. In its place, a more detailed cost and power flow representation

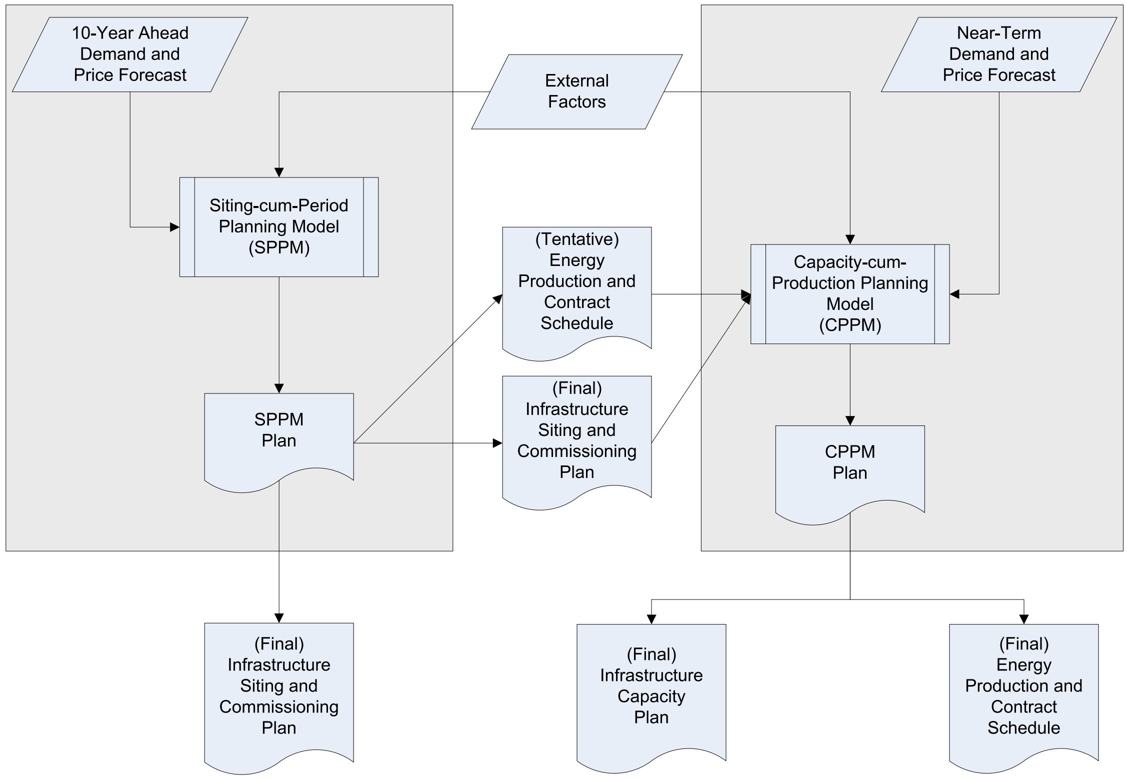

Figure 3.1: Proposed Distribution Planning Framework

can be incorporated, thus rendering the CPPM a NLP model. It should be noted that the energy production schedule obtained from the SPPM is temporary and is revised in the CPPM. The additional accuracy in modelling is introduced in the CPPM plan to more closely reflect the required investments and production schedules.

A planner would typically use the two stages of the framework in tandem, though in some cases the CPPM can be executed independent of the SPPM. The SPPM is suitable for 10-year distribution system planning since it can provide the long lead-times required for infrastructure investments (e.g. when procuring sites or right-of-ways). However, as the future plays out, modifications to capacities and production/contract schedules may be necessary, which is carried out using the CPPM executed annually through the 10-year plan horizon; important since the demand and price forecasts used in the SPPM may not be very accurate and need to be improved in the near-term.

Obtaining accurate long-term spatial forecasts is a key step in this distribution system planning process, and is required by both the SPPM and CPPM to provide the distribution system planner a good, near-optimal plan. Willis *et al.*, in [85] identified two approaches for obtaining these forecasts: trending, where forecasts of future demands are based on historical data; and land-use, where forecasts are based on the anticipated use of the area in question, *i.e.* zoning, such as residential, commercial, or industrial, etc. This work does not undertake any load forecasting exercise in order to focus more on the planning aspect of the problem. In the test system discussed later, load has been approximated to grow at a constant rate.

3.2.1 Siting-cum-Period Planning Model (SPPM)

The goal of the SPPM is to determine the optimum level of future distribution system investments over a period of 10 years. Output from the SPPM subsequently serves as an input to the CPPM, setting bounds on its decision variables.

The SPPM's inputs include the demand at each bus, estimated/forecast for each year up to horizon. It also encompasses information on available resources and their characteristics such as their unit capital and energy costs as well as their market prices. Policy inputs include the regulatory constraints in place, acceptable discount rates, emissions taxes and caps, budgets, etc. Decisions are made in the SPPM on the near-optimal mix of resources to be installed as well as their siting and dates of commissioning. Tentative decisions are also made for each resource's energy production schedule – the outcome of which is passed to the CPPM, for refinement.

3.2.2 Capacity-cum-Production Planning Model (CPPM)

This model uses the SPPM's output, along with annual demand and price forecasts, to build a detailed planning model with accurate representation of feeder power flows and losses. Adjustments to feeder investments in networked distribution systems may also be made in this stage, since the SPPM is not as robust used in this configuration as it is for radial distribution systems (see Section 3.4.4).

To meet the LDC's goal of cost optimality, the CPPM closely follows the results obtained from the SPPM, adhering to resource installation timing and siting and upper and lower bounds on sizing, above and below the SPPM sizes. The detailed power flow modelling in the CPPM also requires additional, separate data: initial feeder impedances and any revised impedances resulting from upgrades. The CPPM determines near-optimal resource investment capacity and annual production/contract schedules across load blocks. Any differences from the SPPM emanate from the CPPM's more accurate modelling of power flows and clearer outlook on future scenarios.

3.3 SPPM: Mathematical Description

3.3.1 Objective Function

The objective function, J_1 in (3.1), is the present value of the total system cost of distribution system investments over the planning horizon from the viewpoint of the LDC. The present values are calculated using different discount rates for capital and energy cost components ($R^{LDC.c}$ and $R^{LDC.e}$ respectively), because the planner may perceive different risk levels for each. The objective function is discussed in detail in the following subsections.

$$
\begin{aligned}
J_1 = \min \sum_{t=1}^{T} \Bigg(& \frac{1}{(1+R^{LDC.c})^t} \Bigg(\\
& \sum_{\substack{i,j \in N: \\ \exists (i,j)}} (Cc_t^{fdr.f} Ge_{(i,j)} Le_{(i,j)} z_{(i,j),t}^{fdr} + Cc_t^{fdr.v} w_{(i,j),t}^{fdr}) \quad \mathrm{a} \\
& + \sum_{i \in N^{ss}} (Cc_t^{ss.f} z_{i,t}^{ss} + Cc_t^{ss.v} w_{i,t}^{ss}) \quad \mathrm{b} \\
& + \sum_{i \in N^{int}} (Cc_t^{int.f} z_{i,t}^{int} + Cc_t^{int.v} w_{i,t}^{int}) \quad \mathrm{c} \\
& + \sum_{q \in Q, i \in N} (Cc_{q,t}^{dg} w_{q,i,t}^{dg}) \Bigg) \quad \mathrm{d} \\
& + \frac{1}{(1+R^{LDC.e})^t} \Bigg(\\
& \sum_{i \in N^{ss}, b \in B} P_{i,b,t}^{ss} Hrs_b Ce_{b,t}^{ss} \quad \mathrm{e} \\
& + \sum_{i \in N^{int}, b \in B} P_{i,b,t}^{int} Hrs_b Ce_{b,t}^{int} \quad \mathrm{f} \\
& + \sum_{\substack{q \in Q, i \in N^{int}, \\ b \in B}} (P_{q,i,b,t}^{dg} (Hrs_b Co_q^{dg})) \quad \mathrm{g} \\
& + \sum_{\substack{k \in K, i \in N_k, \\ b \in B}} (P_{k,i,b,t}^{dg} Hrs_b Ce_{k,b,t}^{dg}) \quad \mathrm{h} \\
& + Ct_t^{CO_2} CO2_t^{xs} \quad \mathrm{i} \\
& - \sum_{i \in N^{ss}, b \in B} P_{i,b,t}^{x} Hrs_b Ce_{b,t}^{x} \Bigg) \Bigg) \quad \mathrm{j} \qquad (3.1)
\end{aligned}
$$

Capital Costs

The engineering, procurement, and construction (EPC) costs and capacity costs of feeder placement are represented in (a).[2] The EPC cost of a feeder is dependent on its length Le and the geographic multiplier Ge representing location dependent features (e.g. a pre-existing right-of-way will be assigned a low Ge value while a remote connectivity will have high Ge). The EPC and capacity costs for substation and intertie builds are represented by the terms (b) and (c), respectively. The capital cost of utility owned DG, which varies by technology, is given in (d). Capital costs of SPP-DG units are not considered in (3.1) as they are not paid for by the LDC. Note that builds may be at new or existing sites.

Energy Purchase and Production Costs, Emissions Costs

The cost to the LDC for importing energy from the external grid/electricity market via substations is given in line (e) while line (f) denotes the cost of power imported from neighbouring discos via interties. The LDC's cost of operating its own DG is given in line (g). Line (h) represents the cost of energy purchased by the LDC from SPP-DG assumed to be based on a contract price fixed a priori.

The costs arising from a CO_2 tax scheme, that may be enforced by the government, is in line (i). It can either represent a strict tax where all CO_2 emissions are taxed or a 'cap and tax' scheme where CO_2 emissions over a certain allowable limit are taxed, as will be discussed in the context of CO_2 emission constraints.

Finally, the last term (j) is the revenue earned by the LDC for power exports to the grid via substations.

3.3.2 Constraints

Nodal Power Balance

A linear power flow representation (3.2) is used in this stage, which requires lesser computation to find an optimum solution than non-linear representations. Feeder losses are approximated by a loss factor, $Ll^{fdr}_{(i,j),t}$, and are accounted for in the incoming power flow direction at the bus. Reserve margins are included as part of nodal demand. Eqs. (3.3) and (3.4) ensure that the net power flow on a given feeder is in one direction only. Note that, for accounting purposes, exports and imports are regarded as separate transactions.

[2]The notation $i, j \in N : \exists(i, j)$ under the summation restricts the combinations of (i, j) to those that are connected, or could be connected, by feeders.

$$\sum_{j \in N:\exists(i,j)} ((1 - Ll^{fdr}_{(j,i),t}) P^{fdr}_{(j,i),b,t} - P^{fdr}_{(i,j),b,t})$$
$$= P^{x}_{i,b,t} + (1 + Rs) Pd_{i,b,t} - P^{ss}_{i,b,t} - P^{int}_{i,b,t} - \sum_{q \in Q} P^{dg}_{q,i,b,t} - \sum_{k \in K} P^{dg}_{k,i,b,t}$$
$$\forall i \in N, b \in B, t \in T \quad (3.2)$$

$$P^{fdr}_{(i,j),b,t} \leq M z^{pf}_{(i,j),b,t} \qquad \forall i, j \in N : \exists\ (i, j) \quad (3.3)$$
$$P^{fdr}_{(j,i),b,t} \leq M(1 - z^{pf}_{(i,j),b,t}) \qquad \forall i, j \in N : \exists\ (i, j) \quad (3.4)$$
$$P^{fdr}_{(i,j),b,t} \geq 0 \qquad \forall i, j \in N : \exists\ (i, j) \quad (3.5)$$

Feeder Capacity Limits

Feeder thermal limits (3.6) are imposed to limit the loading of feeders; these limits take into consideration the new feeder investments, in (3.7). A step increase in feeder capacity, $W^{fdr.st}$, sets the initial capacity at year-0 as well as at the end of life (EOL) when a value equal to the negative of initial size is used.

$$P^{fdr}_{(i,j),b,t} \leq \sum_{t'=1}^{t} (W^{fdr.st}_{(i,j),t'} + w^{fdr}_{(i,j),t'} + w^{fdr}_{(j,i),t'})$$
$$\forall i, j \in N : \exists\ (i, j), b \in B, t \in T \quad (3.6)$$
$$w^{fdr}_{(i,j),t} \leq M z^{fdr}_{(i,j),t} \qquad \forall i, j \in N : \exists\ (i, j), t \in T \quad (3.7)$$

Capacity Adequacy Limits

The capacity adequacy constraint (3.8) ensures enough capacity in the system so that power can be maintained during peak hours in case of equipment failure. This constraint ensures that 80% of substation and intertie capacity, in addition to DG capacity adjusted for their expected capacity factor, (ECF), is adequate to meet peak demand plus reserve for any given year.

$$0.8 \sum_{i \in N} \Big(\sum_{t'=1}^{t} (W^{ss.st}_{i,t'} + w^{s}_{i,t'}) + \sum_{t'=1}^{t} (W^{int.st}_{i,t'} + w^{int}_{i,t'}) \Big) + (W^{dg.ini}_{q,i}$$
$$+ \sum_{t'=1}^{t} w^{dg}_{q,i,t'}) ECF_{q,\text{‘}peak'} + W^{dg}_{k} z^{dg}_{i,k} Op_{k,t} ECF_{k,\text{‘}peak'}$$
$$\geq \sum_{i}^{N} (1 + Rs) Pd_{i,'peak',t} \qquad \forall t \in T \quad (3.8)$$

Substation Capacity Limits

Energy purchased from the external grid/electricity market is transferred to the distribution system via substations, whose associated capacity constraints are given in Eqs. (3.9) to (3.15). The total rated transformer capacity determines the maximum amount of power that can be imported/exported to/from the distribution system, as in (3.9) and (3.10), respectively. As in (3.6), a substation capacity addition step size $W^{ss.st}$ is used to set initial substation sizes and EOL. The maximum allowable capacity is set in (3.11), while (3.12) sets the minimum size by which a substation can be upgraded. Eqs. (3.12) to (3.14) set the binary constraints and (3.15) limits the number of substations that can be built.

$$P^{ss}_{i,b,t} \leq \sum_{t'=1}^{t}(W^{ss.st}_{i,t'} + w^{ss}_{i,t'}) \qquad \forall i \in N^{ss}, t \in T \tag{3.9}$$

$$P^{x}_{i,b,t} \leq \sum_{t'=1}^{t}(W^{ss.st}_{i,t'} + w^{ss}_{i,t'}) \qquad \forall i \in N^{ss}, t \in T \tag{3.10}$$

$$\sum_{t=1}^{T}(W^{ss.st}_{i,t} + w^{ss}_{i,t}) \leq W^{ss.max}_{i} \qquad \forall i \in N^{ss} \tag{3.11}$$

$$w^{ss}_{i,t} \geq W^{ss.min} z^{ss}_{i,t} \qquad \forall i \in N^{ss}, t \in T \tag{3.12}$$

$$w^{ss}_{i,t} \leq M z^{ss}_{i,t} \qquad \forall i \in N^{ss}, t \in T \tag{3.13}$$

$$z^{ss}_{i} M \geq \sum_{t}^{T}(W^{ss.st} + z^{ss}_{i,t}) \qquad \forall i \in N^{ss} \tag{3.14}$$

$$\sum_{i \in N^{ss}} z^{ss}_{i} \leq ss^{max} \tag{3.15}$$

Feeder Configuration

Additional reliability may be achieved by placing (select) buses in a loop or network configuration through (3.16) and (3.17). N^{loop}_{x} is the subset of buses to be connected in loop x. For loop configurations, the right-hand-side of (3.17) is 2, and 3+ for network configurations.

$$z^{fdr}_{(i,j),t} \leq M \sum_{t'=1}^{t}(W^{fdr.st}_{(i,j),t'} + w^{fdr}_{(i,j),t'} + w^{fdr}_{(j,i),t'}) \qquad \forall i,j \in N : \exists\ (i,j), t \in T \tag{3.16}$$

$$\sum_{j \in N^{loop}_{x}} z^{fdr.b}_{(i,j),t} \geq 2 \qquad \forall i \in N^{loop}_{x}, t \in T \tag{3.17}$$

Intertie Capacity Limits

It is assumed the distribution systems connected via interties share the same voltage and thus transformers are not required; limits are set by the neighbouring LDC. These constraints, (3.18) to (3.20), are similar to the substation constraints.

$$P^{int}_{i,b,t} \le \sum_{t'=1}^{t} (W^{int.st}_{i,t'} + w^{int}_{i,t'}) \qquad \forall i \in N^{int}, b \in B, t \in T \qquad (3.18)$$

$$\sum_{t=1}^{T} (W^{int.st}_{i,t} + w^{int}_{i,t}) \le W^{int.max}_{i} \qquad \forall i \in N^{int}, t \in T \qquad (3.19)$$

$$w^{int}_{i,t} \le M z^{int}_{i,t} \qquad \forall i \in N^{int}, t \in T \qquad (3.20)$$

Utility-DG Capacity Limits

DG units may either be utility or SPP-owned (as permitted). The planner sets technology, size, and placement for their LDC's DG units, whose energy is limited by its initial capacity, any upgrade, and expected capacity factor, in (3.21). Eqs. (3.22), (3.23), and (3.24) limits max and min sizes.

$$P^{dg}_{q,i,b,t} Hrs_b \le ECF_{q,b}(W^{dg.ini}_{q,i} + \sum_{t'=1}^{t} w^{dg}_{q,i,t'}) Hrs_b$$
$$\forall q \in Q, i \in N, b \in B, t \in T \quad (3.21)$$

$$\sum_{t}^{T} (W^{dg.ini}_{q,i} + w^{dg}_{q,i,t}) \le W^{dg.max}_{q} \qquad \forall q \in Q, i \in N \qquad (3.22)$$

$$w^{dg}_{q,i,t} \ge W^{dg.min}_{q} z^{dg}_{q,i,t} \qquad \forall q \in Q, i \in N, t \in T \qquad (3.23)$$

$$w^{dg}_{q,i,t} \le M z^{dg}_{q,i,t} \qquad \forall q \in Q, i \in N, t \in T \qquad (3.24)$$

SPP-DG Capacity Limits

The planner may have no control over the size, location, or time of SPP-DG investments. Nevertheless, generation from SPP-DG must be included in the SPPM as given by (3.25) and (3.26). Under *special* circumstances the planner may be able to set the location(s) at which an SPP may place their DG, or, alternatively, it may want to find the preferred locations for SPP-DG (e.g., for subsidies to encourage investment). Equations (3.25) and (3.26) allow for the utility to exercise these options. Otherwise, placement can be fixed at specific bus as per the SPP's decision.

Eq. (3.26) is applied if the LDC has control over the dispatch of energy from SPP-DG; otherwise, if the utility is mandated to purchase all the energy produced by SPPs, (3.26) is an equality.

$$\sum_{i \in N_k} z_{i,k}^{dg} = 1 \qquad \forall k \in K \tag{3.25}$$

$$P_{k,i,b,t}^{dg} Hrs_b \leq ECF_{k,b}(W_k^{dg}) z_{i,k}^{dg}(Op_{k,t}) Hrs_b \qquad \forall k \in K, i \in N_k, b \in B, t \in T \tag{3.26}$$

Utility and SPP-DG Capacity Limits

Minimum and/or maximum DG penetration, as determined by the regulator, is enforced by (3.27) and (3.28).

$$\sum_{\substack{q \in Q \\ i \in N}} P_{q,i,b,t}^{dg} + \sum_{\substack{k \in K \\ i \in N_k}} P_{k,i,b,t}^{dg} \leq DG^{max} \Big(\sum_{i \in N} (1 + Rs) Pd_{i,b,t} + \sum_{i \in N} P_{i,b,t}^{x} \Big) \qquad \forall b \in B, t \in T \tag{3.27}$$

$$\sum_{\substack{q \in Q \\ i \in N}} P_{q,i,b,t}^{dg} + \sum_{\substack{k \in K \\ i \in N_k}} P_{k,i,b,t}^{dg} \geq DG^{min} \Big(\sum_{i \in N} (1 + Rs) Pd_{i,b,t} + \sum_{i \in N} P_{i,b,t}^{x} \Big) \qquad \forall b \in B, t \in T \tag{3.28}$$

Budget Limits

The annual capital expenditures on feeders, substations, interties, and utility-owned DG, made by the LDC is limited by an allowable budget, Bgt (3.29).

$$a + b + c + d \leq Bgt_t^{LDC} \qquad \forall t \in T \tag{3.29}$$

CO_2 Emissions Tax and Capacity Limits

Two sources of air pollution that can be attributed to DG: CO_2 and NO_x; CO_2 currently garners the most attention by policy makers and is therefore the focus of (3.30). This constraint calculates all excess CO_2 emissions above $CO2_t^{cap}$. Used in conjunction with i of (3.1), it gives either a strict emissions tax or a ‘cap and tax’ scheme. It is assumed that the LDC picks up the additional costs associated with pollution from SPP-DG, as economically, the additional costs are usually passed along. Emissions associated with the import of energy via substations and interties are not included because they are generated outside the jurisdiction of the LDC and thus are assumed not to be of immediate concern to it. It may also be assumed that these external sources are subject to their own emissions limits.

$$\sum_{\substack{q\in Q,i\in N,\\ b\in B}} P^{dg}_{q,i,b,t} Hrs_b CO2^{dg}_q + \sum_{\substack{k\in K,i\in N_k,\\ b\in B}} P^{dg}_{k,i,b,t} CO2^{dg}_k \leq CO2^{cap}_t + CO2^{xs}_t \qquad \forall t \in T \quad (3.30)$$

Variable Limits

$CO2^{xs}_t$, $P_{(i,j),b,t}$, $P^{dg}_{q,i,b,t}$, $P^{dg}_{k,i,b,t}$, $P^{int}_{i,b,t}$, $P^{ss}_{i,b,t}$, $P^{x}_{i,b,t}$, $w^{dg}_{q,i,t}$, $w^{fdr}_{(i,j),t}$, $w^{int}_{i,t}$, and $w^{ss}_{i,t}$ are positive; $z^{dg}_{k,q,i,t}$, $z^{dg}_{q,i,t}$, $z^{dg^P}_{i,k}$, $z^{fdr}_{(i,j),t}$, $z^{int}_{i,t}$, $z^{pf}_{(i,j),b,t}$, $z^{ss}_{i,t}$, and z^{ss}_{i} are binary.

3.4 CPPM: Mathematical Description

The CPPM takes as input the distribution system resource upgrades/installations, their locations, and build dates obtained from the SPPM and determines the capacity (within pre-defined bounds) with accurate power flow representation, including losses and voltage drop constraints. Variables from the SPPM entering the CPPM as parameters are denoted with the prefix '*sp.*'.

3.4.1 Objective Function

The objective function J_2 of the CPPM (3.31) does not have the fixed costs that appear in J_1 of the SPPM; capital cost are given in lines k to m and energy and production costs are given in lines (n) to (s).

$$
\begin{aligned}
J_2 = \min \sum_{t=1}^{T} \Bigg(& \frac{1}{(1+R^{LDC.c})^t} \Bigg(\\
& \sum_{\substack{j \in N: \\ \exists (i,j)}} (Cc_t^{fdr.v} w_{(i,j),t}^{fdr}) \quad \text{(k)} \\
& + \sum_{i \in N^{ss}} (Cc_t^{ss.v} w_{i,t}^{ss}) + \sum_{i \in N^{int}} (Cc_t^{int.v} w_{i,t}^{int}) \quad \text{(l)} \\
& + \sum_{q \in Q, i \in N} (Cc_{q,t}^{dg} w_{q,i,t}^{dg}) \Bigg) \quad \text{(m)} \\
& + \frac{1}{(1+R^{LDC.e})^t} \Bigg(\\
& \sum_{i \in N^{ss}, b \in B} P_{i,b,t}^{ss} Hrs_b Ce_{b,t}^{ss} \quad \text{(n)} \\
& + \sum_{i \in N^{int}, b \in B} P_{i,b,t}^{int} Hrs_b Ce_{b,t}^{int} \quad \text{(o)} \\
& + \sum_{\substack{q \in Q, i \in N^{int}, \\ b \in B}} P_{q,i,b,t}^{dg} Hrs_b Co_q^{dg} \quad \text{(p)} \\
& + \sum_{k \in K, i \in N_k,\ b \in B} P_{k,i,b,t}^{dg} Hrs_b Ce_{k,b,t}^{dg} \quad \text{(q)} \\
& + CO2_q^{dg} CO2_t^{xs} \quad \text{(r)} \\
& - \sum_{i \in N^{ss}, b \in B} P_{i,b,t}^{x} Hrs_b Ce_{b,t}^{x} \Bigg) \Bigg) \quad \text{(s)}
\end{aligned} \tag{3.31}
$$

3.4.2 Constraints

Power flow

A non-linear approximation of the power flow and losses, same as in [49], is used in (3.32). Feeder impedance $absZ$ is set by the planner according to output from the SPPM. If the feeder segment is unchanged then its impedance will be identical to its initial value, otherwise its value will reflect any upgrades. Like (3.2), exports and imports are regarded as separate transactions.

$$\sum_{j \in N : \exists (i,j)} P^{fdr}_{(j,i),b,t} - \frac{(V_{j,b,t} - V_{i,b,t})^2}{absZ_{(i,j),t}} = P^{x}_{i,b,t}$$
$$+ (1 + Rs)Pd_{i,b,t} - P^{ss}_{i,b,t} - P^{int}_{i,b,t} - \sum_{q \in Q} P^{dg}_{q,i,b,t} - P^{dg}_{k,i,b,t}$$
$$\forall i \in N, b \in B, t \in T \quad (3.32)$$

where

$$P^{fdr}_{(i,j),b,t} = V_{i,b,t} \frac{(V_{i,b,t} - V_{j,b,t})}{absZ_{(i,j),t}} \qquad \forall i, j \in N : \exists\ (i,j) \quad (3.33)$$

Bus Voltage Limits

The voltage profile is maintained within specified limits. Since reactive power and voltage support devices are not modelled, these limits may be larger than typical.

$$V_{i,b,t} \leq V^{max} \qquad \forall i \in N, b \in B, t \in T \quad (3.34)$$
$$V_{i,b,t} \geq V^{min} \qquad \forall i \in N, b \in B, t \in T \quad (3.35)$$

3.4.3 Power Adequacy Limits

The equation for power adequacy limits in the CPPM is similar to that in the SPPM (3.8).

Feeder Capacity Limits

The equation for feeder capacity limits in the CPPM (3.36) is identical to (3.6). Additionally, bounds are set (3.37), (3.38) on feeder builds based on input from the SPPM.

$$P^{fdr}_{(i,j),b,t} \leq \sum_{t'=1}^{t} (W^{fdr.st}_{(i,j),t'} + w^{fdr}_{(i,j),t'} + w^{fdr}_{(j,i),t'})$$
$$\forall i, j \in N : \exists\ (i,j), b \in B, t \in T \quad (3.36)$$

$$w^{fdr}_{(i,j),t} \geq (Lo)sp.w^{fdr}_{(i,j),t} \qquad \forall i, j \in N : \exists\ (i,j), t \in T \quad (3.37)$$
$$w^{fdr}_{(i,j),t} \leq (Hi)sp.w^{fdr}_{(i,j),t} \qquad \forall i, j \in N : \exists\ (i,j), t \in T \quad (3.38)$$

Substation Capacity Limits

Constraints limiting substation capacity in the CPPM are identical to (3.9)-(3.11). Bounds are also set (3.39), (3.40) on substation builds based on input from the SPPM.

$$w^{ss}_{i,t} \geq (Lo)sp.w^{ss}_{i,t} \qquad \forall i \in N^{ss}, t \in T \tag{3.39}$$
$$w^{ss}_{i,t} \leq (Hi)sp.w^{ss}_{i,t} \qquad \forall i \in N^{ss}, t \in T \tag{3.40}$$

Intertie Capacity Limits

The intertie capacity limits constraints in the CPPM are the same as (3.18) and (3.19) Bounds are set (3.41) to (3.42) on intertie builds based on input from the SPPM.

$$w^{int}_{i,t} \geq (Lo)sp.w^{int}_{i,t} \qquad \forall i \in N^{int}, t \in T \tag{3.41}$$
$$w^{int}_{i,t} \leq (Hi)sp.w^{int}_{i,t} \qquad \forall i \in N^{int}, t \in T \tag{3.42}$$

Utility-DG Capacity Limits

Equations setting utility-DG capacity limits in the CPPM are identical to (3.21) and (3.22). Bounds are set (3.39) and (3.40) on utility-DG builds based on input from the SPPM.

$$w^{dg}_{q,i,t} \geq (Lo)sp.w^{dg}_{q,i,t} \qquad \forall q \in Q, i \in N, t \in T \tag{3.43}$$
$$w^{dg}_{q,i,t} \leq (Hi)sp.w^{dg}_{q,i,t} \qquad \forall q \in Q, i \in N, t \in T \tag{3.44}$$

SPP-DG Capacity Limits

Equations (3.45) to (3.47) are applied if the LDC has control over the amount of energy it may purchase/contract from SPP-DG. Else, if the LDC is mandated to purchase/contract all SPP-DG energy, then (3.48) applies.

$$P^{dg}_{k,i,b} \geq (Lo)sp.P^{dg}_{k,i,b,t} \qquad \forall k \in K, i \in N_k, b \in B \tag{3.45}$$
$$P^{dg}_{k,i,b} \leq (Hi)sp.P^{dg}_{k,i,b,t} \qquad \forall k \in K, i \in N_k, b \in B \tag{3.46}$$
$$P^{dg}_{k,i,b}Hrs_b \leq ECF_{k,b}W^{dg}_{k}Hrs_b \qquad \forall k \in K, i \in N_k, b \in B \tag{3.47}$$
$$P^{dg}_{k,i,b} = sp.P^{dg}_{k,i,b,t} \qquad \forall k \in K, i \in N_k, b \in B \tag{3.48}$$

Utility and SPP-DG Capacity Limits

Constraints on DG penetration limits in the CPPM are the same as in (3.27) and (3.28).

CO_2 Emissions Tax and Capacity Limits

The CO_2 Emissions Tax and Capacity limits in the CPPM are identical to those of the SPPM (3.30).

Variable Limits

Variables $CO2^{xs}_{t}$, $P^{dg}_{q,i,b,t}$, $P^{dg}_{k,i,b,t}$, $P^{int}_{i,b,t}$, $P^{ss}_{i,b,t}$, $P^{x}_{i,b,t}$, $V_{i,b,t}$, $w^{dg}_{q,i,t}$, $w^{fdr}_{(i,j),t}$, $w^{int}_{i,t}$, and $w^{ss}_{i,t}$ are positive; $P^{fdr}_{(i,j),b,t}$ is unrestricted in sign.

3.4.4 Network Check

In networked distribution systems, the power flow approximations used in the SPPM yield feeder capacity addition recommendations that may make the CPPM problem infeasible. In order to assess the need for the above fix, equations (3.31) and (3.36) must be modified. Line m of the objective function J_2, (3.31), becomes

$$+\sum_{q\in Q, i\in N}(Cc^{dg}_{q,t}w^{dg}_{q,i,t})\Big) + \sum_{i,j\in N:\exists(i,j)} w^{fdr.pen}_{i,j,t}M^{fdr}, \tag{3.49}$$

where M^{fdr} is a large value. Equation (3.36) becomes

$$P^{fdr}_{(i,j),b,t} \leq \sum_{t'=1}^{t}(W^{fdr.st}_{(i,j),t'} + w^{fdr}_{(i,j),t'} + w^{fdr}_{(j,i),t'} + w^{fdr.pen}_{(i,j),t'} + w^{fdr.pen}_{(j,i),t'})$$
$$\forall i,j \in N : \exists\ (i,j), b \in B, t \in T \tag{3.50}$$

Fig. 3.2 illustrates the network check and fix.

3.4.5 Reactive Power Planning

The SPPM and CPPM assume that the distribution system operates at unity power factor and thus reactive power does not contribute significantly to the current flow along feeders. In distribution systems with reactive power support and energy from sources at unity power factor (such as substations, interties, and synchronous DG) this assumption is accurate. However, some DG technologies, such as wind turbines with induction generators, can draw significant reactive power (if they do not have their own source) and thus additional feeder capacity may be required above that anticipated in the model.

In such an instance where DG may have large reactive power requirements, and thus the assumption of unity power factor is not valid, the framework will need to be adjusted. Using full load flow equations in the SPPM will not likely be possible

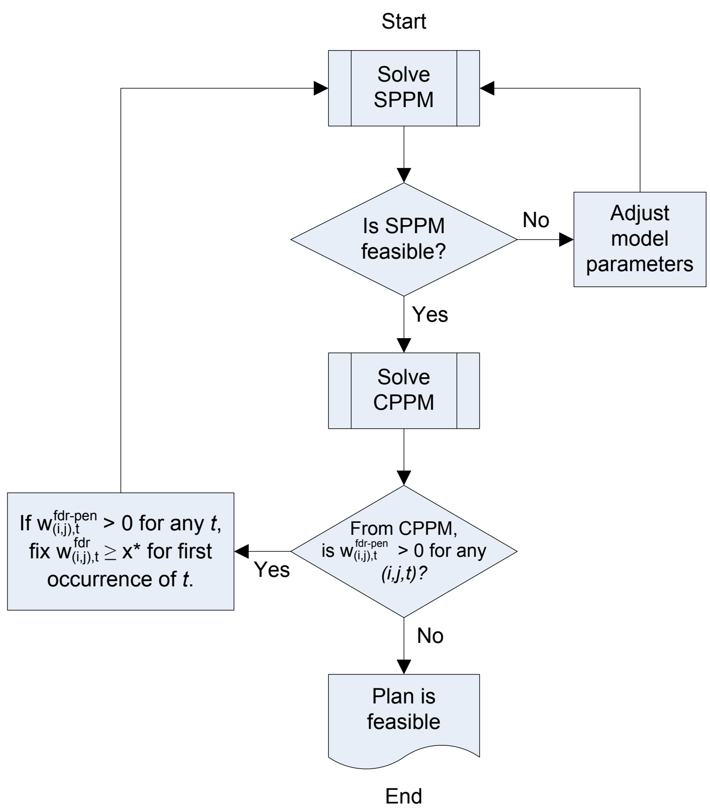

Figure 3.2: SPPM and CPPM Network Check

Table 3.1: Investment Costs of Utility Resources [50], [9], [10]

Element	EPC Cost		Capital Cost	
	Symbol	Cost (Year-0)	Symbol	Cost (Year-0)
Feeder	$Cc_t^{fdr.f}$	\$150,000/km	$Cc_t^{fdr.v}$	\$1,000/MW
Substation	$Cc_t^{ss.f}$	\$200,000	$Cc_t^{ss.v}$	\$50,000/MW
Intertie	$Cc_t^{int.f}$	\$200,000	$Cc_t^{int.v}$	\$1,000/MW
Diesel Engine DG	-	-	$Cc_{k,t}^{dg.f}$	\$400,000/MW
Gas Turbine DG	-	-	$Cc_{k,t}^{dg.f}$	\$825,000/MW
Solar-PV DG	-	-	$Cc_{k,t}^{dg.f}$	\$7,500,000/MW
Wind Turbine DG	-	-	$Cc_{k,t}^{dg.f}$	\$2,500,000/MW

due to the complexities of a MINLP model. Adjusting the model appropriately is an area of future research, and may involve reworking the CPPM to accommodate full load and power flow modelling, or approximating MVA flows by estimating power factors.

3.5 Description of Radial Distribution Test System

To demonstrate the suitability of the proposed distribution system planning framework, a 32-bus radial distribution system [86] is considered for the studies (Fig. 3.3). The system demand has been scaled to suit the problem case requirements and supplemented with the additional technical details of feeder, intertie, and substation limits, and DG options.

The system is comprised of 32 buses split among 4 branches with a grid-connected substation at bus-1 and a *candidate* intertie site at bus-30. The total system peak demand is 37 MW (including reserve) in year-0 and grows 3% annually. Each feeder segment is 1 km long, has Ge=0.4, and a loss factor of 2% (which results in a total loss of approximately 7% in the SPPM). Shown in the diagram, beside each feeder segment, are the peak feeder flows (in MVA) and feeder limits at year-0. Feeder segment $(18, 19)$ has an expected EOL at year-3. It is also stated in advance that the LDC will have to accommodate three SPP-DG investments whose details are in Table 3.3.

Table 3.1 provides the investment costs of the resources available to the LDC. Utility-owned DG resources only have per unit capital costs and their EPC cost is assumed to be insignificantly small in comparison. These DGs must have a minimum capacity of 3 MW.

The cost of generation from utility-owned DG is given in Table 3.2. Energy

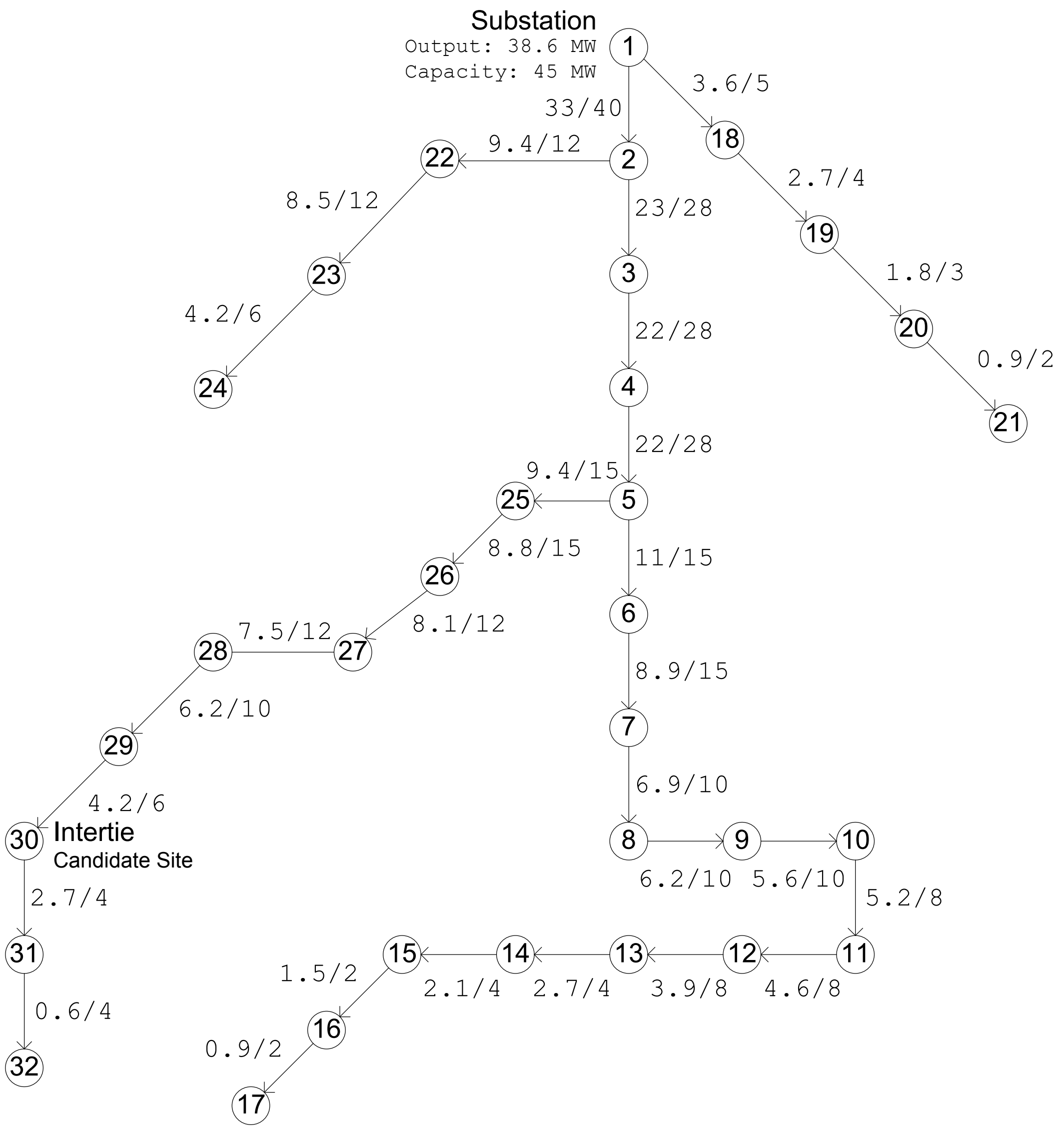

Figure 3.3: 32-Bus Radial Distribution System. The circled numbers denote bus numbers while the number a/b beside each feeder segment gives the initial power flow/feeder capacity, in MVA.

Table 3.2: Price or Cost of Energy from Utility Resources [9], [10], [11]

Resource	Price/Cost (Year-0)		
	Base	Intermediate	Peak
Market, $Ce_{b,t}^{ss}$	\$75/MWh	\$92/MWh	\$110/MWh
Neighbouring LDC, $Ce_{b,t}^{int}$	\$50/MWh	\$70/MWh	\$100/MWh
For Export, $Ce_{b,t}^{x}$	\$73/MWh	\$90/MWh	\$108/MWh
Diesel Engine DG, $Co_{q,t}^{dg}$	\$90/MWh	→	\$90/MWh
Gas Turbine DG, $Co_{q,t}^{dg}$	\$75/MWh	→	\$75/MWh
Solar-PV DG, $Co_{q,t}^{dg}$	\$4/MWh	→	\$4/MWh
Wind Turbine DG, $Co_{q,t}^{dg}$	\$10/MWh	→	\$10/MWh

Table 3.3: SPP-DG Commissioning Plan (known a priori)

	DG Technology		
	Solar-PV	Natural Gas	Wind Turbine
Number (ID), k	SPP-DG 1	SPP-DG 2	SPP-DG 3
Commissioning , t	Year-2	Year-2	Year-4
Possible Site(s), N_k^{SPP}	Bus-17, 29, 30 31, or 32	Bus-23	Bus-19 or 20
Size, W_k^{dg}	1.5 MW	1.0 MW	2.0 MW

import prices through substations and interties, and export prices, are specified in terms of the three time-blocks of peak, intermediate, and base. Production costs from utility-owned DG units are independent of demand level, and reflect operating, fuel, and maintenance costs. Table 3.4 gives the purchase price of energy from SPP-DG and Table 3.5 gives the expected capacity factor, averaged over all load blocks, and CO_2 emission coefficients from utility and SPP-DG units.

Annual discount rates (for energy and capital) and the rate of change in capital and operating costs of utility-owned DG are given in Tables 3.6 and 3.7, respectively. Capital costs for some utility-owned DG are assumed to decrease as technology improves, whereas diesel and gas prices (and thus operating costs) are expected to increase over time. Other miscellaneous parameters are given in Table 3.8.

3.5.1 End Effects

One important issue in planning models to be considered is end effects, which may occur when the 'finite planning horizon' influences the optimal choice of investments. Without mitigation of this effect large capital expenses will be avoided in

Table 3.4: SPP-DG Energy Contract Prices

Demand Block	Price, $Ce^{dg}_{k,b,t}$ (Year-0)
Base	\$55/MWh
Intm	\$72/MWh
Peak	\$90/MWh

Table 3.5: ECF and CO_2 Emission Coefficients for Utility and SPP-DG

Technology, q	ECF, $ECF_{q,i,b}$	CO_2 Emissions, $CO2^{dg}_{q}$
Diesel Engine	98%	0.65 MT/MWh
Gas Turbine	98%	0.63 MT/MWh
Solar-PV	16.5%	-
Wind Turbine	30%	-

Table 3.6: Finance Rates

Energy Cost and CO_2 Tax Discount Rate, $R^{LDC.e}$	8.0%
Capital Cost Discount Rate, $R^{LDC.c}$	8.0%

Table 3.7: Change in DG Unit Costs over Plan Horizon

Utility-DG	Annual Change in Capital Cost	Annual Change in Operating Cost
Diesel Engine	-	3.0%
Gas Turbine	-	4.0%
Solar-PV	-4.0%	-
Wind Turbine	-1.0%	-

Table 3.8: Miscellaneous Parameters

Description	Value
Emissions Tax, $Ct^{CO_2}_{t}$	\$10/tonne
Emissions Cap, $CO2^{cap}_{t}$	30,000 tonnes/year
Hours in Year, Hrs_b	Base: 4380; Intm: 3504; Peak: 876
Demand (% of Peak)	Base: 50; Intm: 85; Peak: 100
Max DG Penetration, DG^{max}	20%
Voltage Limits, V^{max}/V^{min}	1.05 p.u. Max; 0.95 p.u. Min

Table 3.9: Lifespan of Capital [88]

Element	Lifespan
Substations	30 years
Feeders and Interties	35 years
Diesel Engine	25 years
Gas Turbine DG	25 years
Solar-PV DG	30 years
Wind-Turbine DG	20 years

Table 3.10: Model Statistics - BASE Case

	SPPM	CPPM
Solver	CPLEX	MINOS
Blocks of Equations	34	29
Blocks of Variables	20	13
Single Equations	52,747	21,413
Single Variables	45,198	13,111
Non-Zero Elements	282,026	119,416
Discrete Variables	23,737	N/A
Generation Time (s)	0.859	0.226
Resource Usage (s)	107	43.7
Relative Gap (%)	0.0996	N/A

later years due to the long recovery periods of their costs . To mitigate these effects the framework can be modified to subtract the salvage values of capital investments at the end of the planning horizon. In this work, straight-line depreciation is used [87] to determine salvage values. The expected lifespans of units are given in Table 3.9.

3.5.2 Computational Details

The considered test system was programmed and executed in the GAMS environment [89] on an IBM eServer xSeries 460 with 8 Intel Xeon 2.8 Ghz processors and 3 GB (effective) of RAM. The first stage model, the SPPM, is a MILP model which is solved using CPLEX while the CPPM, which is a NLP model, is solved using MINOS. The model and solver statistics are given in Table 3.10.

The distribution planning problem should ideally be formulated as a single MINLP model. However, with current optimization algorithms such problems are computationally very difficult, even for small sized systems. This approach breaks the problem into MIP and NLP problems. Since a globally optimal solution is near impossible to prove, it is desirable to simply achieve a near-optimal solution.

The SPPM, a MIP solved using CPLEX, was considered acceptable when a relative gap, the difference between the solution and minimum bound, of less than 0.1% was achieved. This gap can be set by the user, but this is considered to be well within any margin of error. As a NLP problem, the CPPM's solution needs a good starting point to give the best possible locally optimal solution. Since this point is generated by the SPPM, it can be considered the best possible given that the SPPM gives a reasonable approximation of the problem.

3.6 Tests, Results, and Discussions

Two different approaches of examining the performance and effectiveness of the proposed distribution system planning framework are employed. The first approach applies the framework as a distribution system planner, so as to make recommendations on a 10 year investment plan and production/contract schedule. The second approach applies the framework as a policy maker, and hence analyzes the impact of multiple policy sets on investments, production/contract schedules, emissions, costs, and system voltage profile.

3.6.1 BASE Case Plan Recommendations

The BASE case represents an energy resource unconstrained distribution planning problem. The LDC is permitted to invest in and operate DG units at its discretion, but is required to purchase all energy produced by SPP-DGs at pre-determined prices. A budgetary limit on annual capital expenditures by the LDC of $10M is imposed. The LDC is allowed to invest in an intertie connection with the neighbouring LDC and can export surplus energy via its substation. A 'cap and tax' CO_2 tax scheme is also included in this case.

Fig. 3.4 depicts the radial distribution system with recommended resource investments accumulated to year-10. Feeder segments that are to be upgraded are denoted by the dotted lines. The feeder power flows shown in Fig. 3.4 are for peak demand periods; the corresponding feeder limits are also shown alongside. The corresponding distribution system investment plan is given in Table 3.11. It is observed that the 10 year plan emphasizes gas turbine DG investments in the first year, which is justifiable given their low capital outlay and low initial operating cost. In later years, investment in gas turbines is not justifiable because of increased operating costs from gas price increases and hence investments in wind turbines are recommended. Note that the plan recommends DG investments be placed near the end of feeder branches where they have the most impact on reducing feeder

Table 3.11: Utility Investment Plan

Year	Investment Size (MW) and Site (Bus)				
	SS, $w^{ss}_{i,t}$	Int, $w^{int}_{i,t}$	Gas Turbine, $w^{dg}_{q,i,t}$	Wind T., $w^{dg}_{q,i,t}$	Feeder $w^{fdr}_{(i,j),t}$
1	-	10 (30)	3.5 (7), 3.0 (12)	-	1.8 (29,30)
	-	-	3.0 (15), 4.1 (24)	-	-
3	-	-	-	-	3.6 (18,19)
7	-	-	-	3.0 (16)	-
9	-	-	-	3.2 (13)	-

losses. One investment in an intertie connection is recommended at the start of the planning period, as this is a cheap source of energy, while no substation upgrades are recommended by the distribution system plan. Among the feeder investments link $(18, 19)$ is a replacement for the existing feeder which is expected to reach its EOL. Buses 17 and 23 were selected for SPP-DG units 1 and 3, respectively, and were placed to maximize loss reduction; the LDC had no influence on the placement of SPP-DG 2.

Table 3.12 presents the LDC's energy production/contract schedules (only even-numbered years are reported for lack of space). The schedules are consistent with the resource assets available to it; the reduction in gas turbine production in later years is due to increased costs of fuel. The intertie is used to its maximum capacity while the substation always has excess capacity available (in part to serve the system's energy adequacy requirement). The export of energy via the substation, which starts in year-1, is a result of the excess generation capacity available from LDC and SPP-DG, which can be sold for additional income.

It is observed that the proposed distribution system planning framework provides a comprehensive set of decisions on new investments, generation, and export/import schedules, keeping in mind the multiple constraints and objectives of the LDC. The application of the proposed framework can be expanded to examine several critical issues pertaining to policies with regard to distribution system planning in a deregulated environment, as discussed next.

Sensitivity Analysis

In deregulated markets, there can be uncertainty in the price of energy. Consequently, it is important to look at the sensitivity of the results to changes in energy prices. To accomplish this, the price of energy to/from the market (Ce^{ss}_{bt}, Ce^{s}_{bt}), the neighbouring LDC (Ce^{int}_{bt}), and contract price for energy from SPP-DG ($Ce^{dg}_{k,b,t}$) are simultaneously adjusted from -20% to +20% of their base prices given in Tables 3.2 and 3.4.

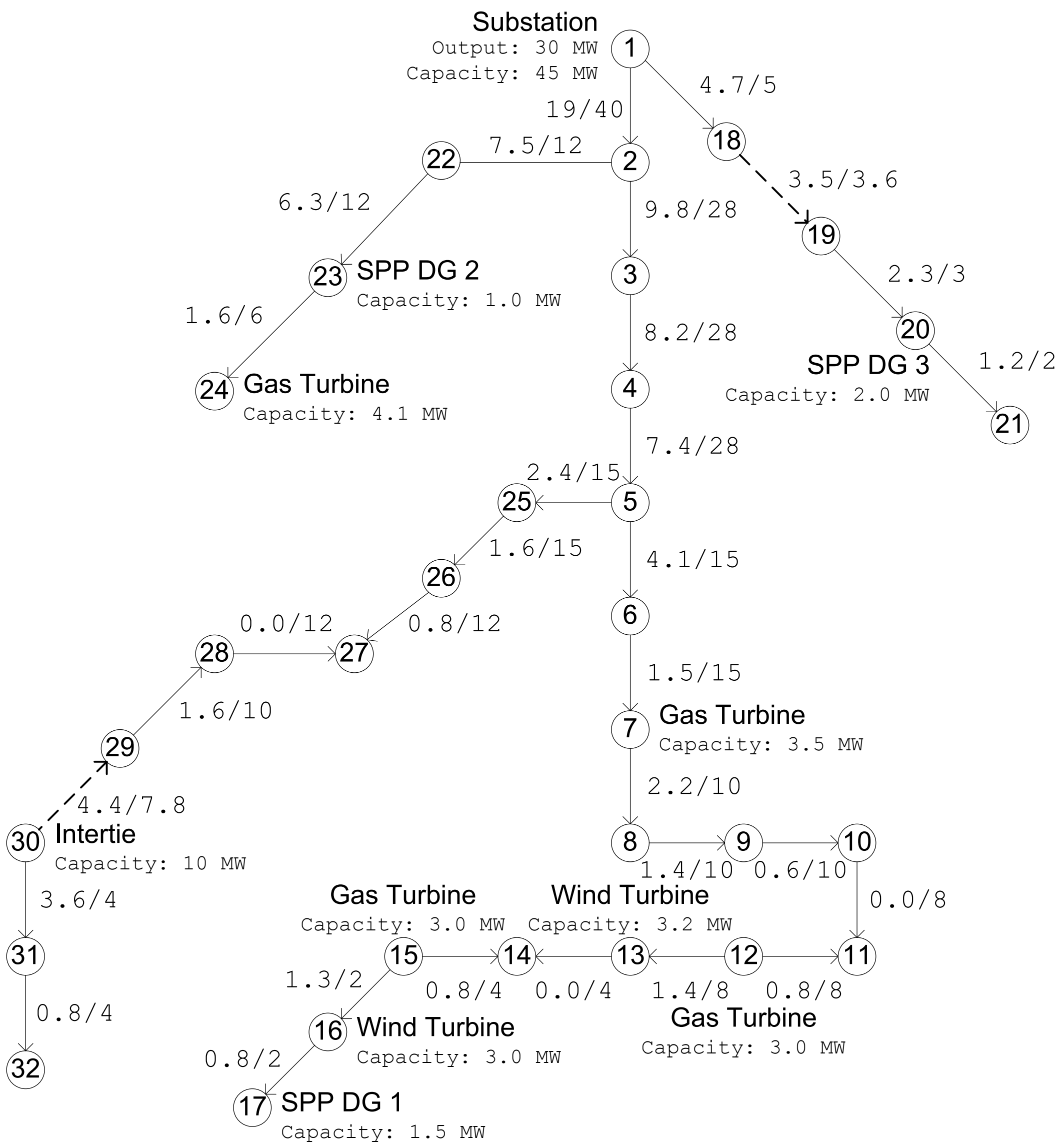

Figure 3.4: Radial Distribution System: Year-10 Peak Flows. Dashed lines indicate upgraded feeder segments.

Table 3.12: LDC Production/Contract Schedules

Supply Element	Bus	Demand Level	Year/Supply (MW) 2	4	6	8	10
Substation (Import)	1	Base	8.8	9.2	10.5	10.6	10.8
		Intm	16.9	18.5	20.8	28.1	29.9
		Peak	21.6	23.6	25.7	27.9	30.2
Intertie (Import)	30	All	10.0	→	→	→	10.0
Gas Turbine	7	Intm	3.48	3.48	-	-	-
		Peak	3.48	→	→	→	3.48
	12	Intm	2.96	2.96	2.64	-	-
		Peak	2.96	→	→	→	2.96
	15	Intm	2.94	2.94	2.57	-	-
		Peak	2.94	→	→	→	2.94
	24	Intm	4.02	4.02	0.18	-	-
		Peak	4.20	→	→	→	4.02
Wind Turbine	14	Base	-	-	-	-	1.26
		Intm	-	-	-	-	0.73
		Peak	-	-	-	-	0.25
	17	Base	-	-	-	1.20	1.20
		Intm	-	-	-	0.69	0.69
		Peak	-	-	-	0.24	0.24
SPP-DG 1	17	Base	0.11	→	→	→	0.11
		Intm	0.38	→	→	→	0.38
		Peak	0.45	→	→	→	0.45
SPP-DG 2	23	All	0.98	→	→	→	0.98
SPP-DG 3	20	Base	-	0.80	→	→	0.80
		Intm	-	0.46	→	→	0.46
		Peak	-	0.16	→	→	0.16
Substation (Export)	1	Intm	8.0	8.1	-	-	-
		Peak	6.9	6.6	6.1	5.8	5.5

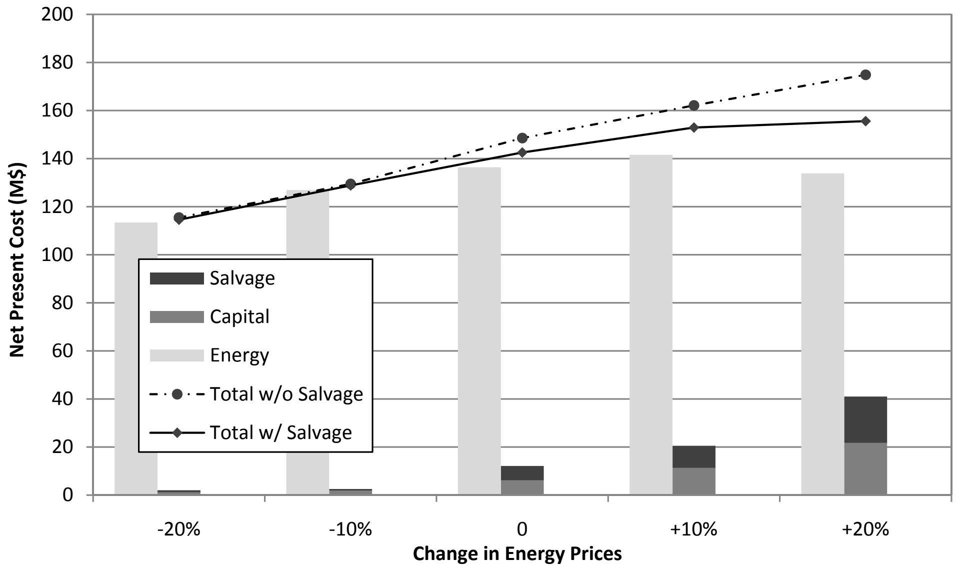

Figure 3.5: Comparison of NPCs Varying Energy Prices

Table 3.13: Comparison of Capital Investments Varying Energy Prices

	Investment Size (MW) and # of Builds			
	Intertie	Gas Turbine	Wind T	Feeder
-20%	10.0 (1)	6.0 (2)	-	5.5 (4)
-10%	10.0 (1)	6.0 (2)	-	5.5 (3)
0	10.0 (1)	13.7 (4)	6.2 (2)	5.4 (2)
+10%	10.0 (1)	23.3 (7)	9.6 (3)	4.5 (2)
+20%	10.0 (1)	52.4 (10)	19.2 (5)	2.9 (2)

The energy, capital, and total costs to the LDC over the 10-year plan period, for the energy price scenarios analyzed, are given in Fig. 3.5. Table 3.13 gives the accumulated capital investments by LDC up to the planning horizon. It is seen that from -20% to +10%, there is a steady increase in energy costs. However, from 0 to +10%, the increased energy costs are mitigated by increased investments in utility DG (both gas and wind). At +20%, energy costs actually decrease due to large wind DG investments.

The LDC's NPC increases commensurate to increasing energy and capital costs. However, between the +10% to +20% mark, it is noted that the NPC begins to level off. At this price point, the increasing costs occur due to capital expenditures in wind and gas DG units; the low operational costs of wind and gas DG (compared to market energy costs), and subsequent export from these sources, mitigate the high cost of purchasing energy from the market.

CO_2 emissions, as shown in Fig. 3.6, jumps significantly with increasing energy

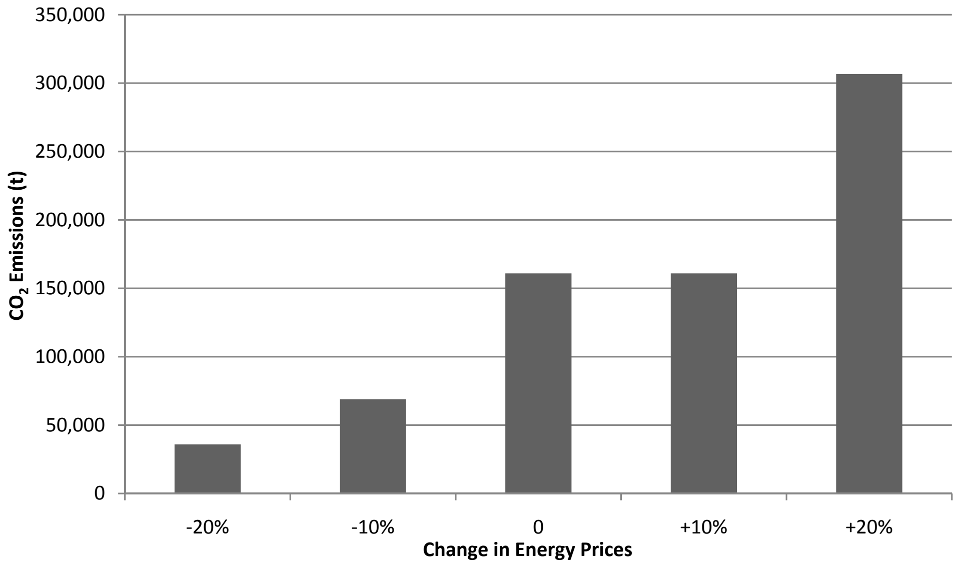

Figure 3.6: Comparison of CO_2 Emissions Varying Energy Prices

prices due to the gas turbines used to replace the more expensive energy imported from the grid. Conversely, losses, in Fig. 3.7, decrease due to increased DG penetration. Predictably, higher prices also correlated to better voltage profiles, in Fig. 3.8, again due to higher penetration of DG.

In essence, higher costs of energy will lead to the increased investment in DG (all else being equal). It is also noted that the increased costs well lead to a technically improved system (in terms of losses and voltage profile) but also much higher CO_2 emissions. From a regulatory standpoint, this may lead to the dilemma of having to increase carbon taxes to mitigate carbon emissions, thus forcing consumers to bear the full brunt of higher energy prices.

3.6.2 Policy Analysis in the Context of Distribution System Planning

In this section, the proposed distribution system planning framework is used to examine the potential impacts of policies and regulations that may be imposed by regulators and governments on discos to achieve certain technical, environmental, social, and/or economic goals. While policy makers may consider several combinations of policies and regulations, the final mix of deployed policies comprise both the constraints themselves and the parameters within. Some policies may be regulatory while others are due of technical limitations. Four cases are constructed, as summarized in Table 3.14, and represent a broad spectrum of realistic policy and technical directives, while also providing exhaustive test cases for the distribution system planning framework. The net present costs (NPCs), new capacity, production schedules, system voltage profiles, and feeder losses of each case are examined

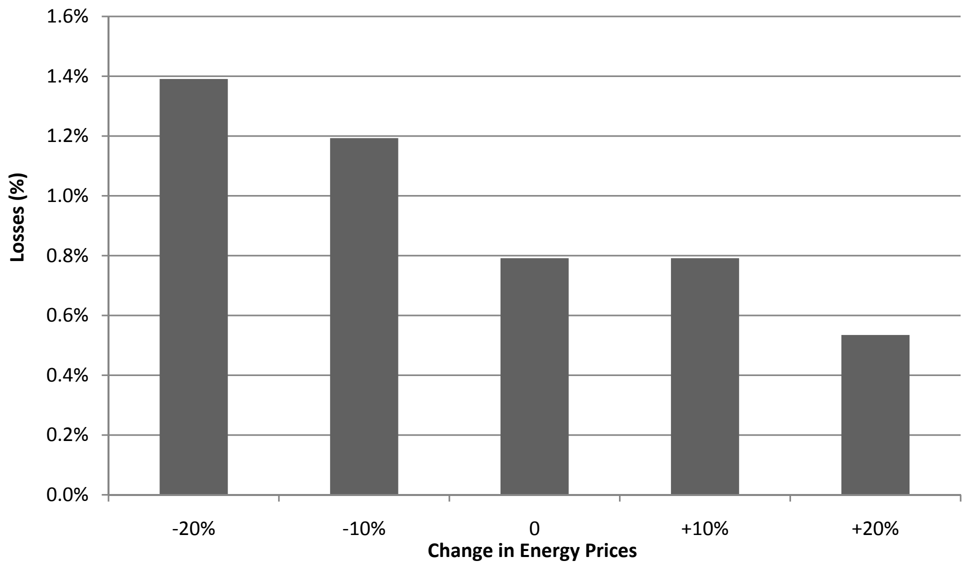

Figure 3.7: Comparison of Distribution Feeder Losses Varying Energy Prices

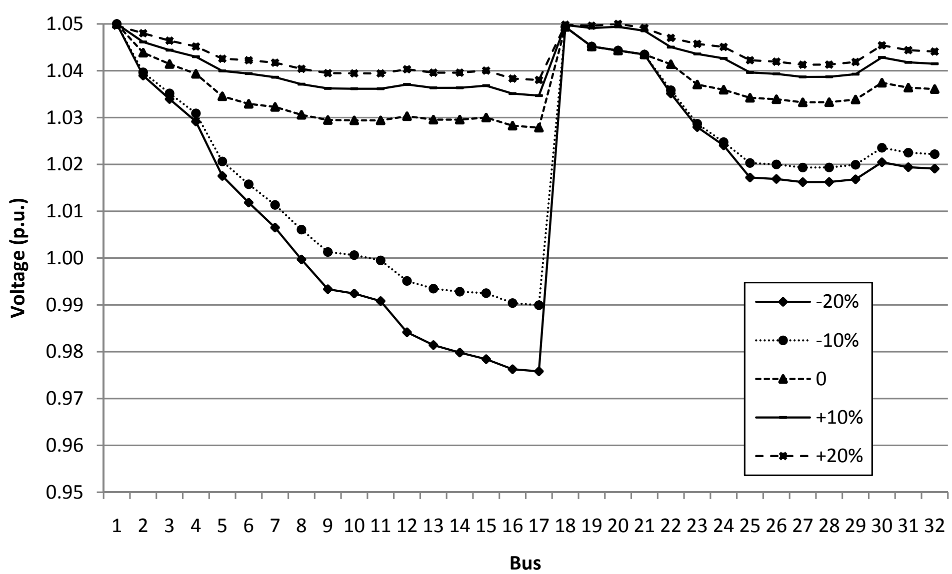

Figure 3.8: Comparison of Voltage Profiles Varying Energy Prices

Table 3.14: Policy Case Studies

Supply and Policy Constraint/Rule	Scenario			
	BASE	REG	OPT	ON
Interties Allowed	Yes	No	Yes	Yes
LDC-Owned DG	Dispatched	Dispatched	Dispatched	Not Available
SPP-DG	Fixed dispatch	Fixed dispatch	Optimal dispatch	Fixed dispatch
DG Maximum Penetration, DG^{max}	20%	20%	20%	20%
Export Allowed	Yes	No	Yes	Yes
CO_2 Tax Scheme	Cap & Tax	No	Cap & Tax	Cap & Tax
Annual Capital Budget, Bgt_t^{LDC}	\$10M	\$10M	\$10M	\$10M

below. Each case assumes that the distribution system planner acts near-optimally within the imposed constraints (i.e. minimizes costs). These cases are discussed in detail below:

- **Base (BASE) Case**: This has already been described in detail above.
- **Regulated (REG) Case**: This policy set imitates scenarios where the LDC is strictly regulated wherein energy imports via interties or exports from the LDC are not permitted. A CO_2 cap and tax scheme is not imposed. All other aspects remain the same as the BASE case.
- **Optimum (OPT) Case**: This is similar to the BASE case except that the LDC is no longer required to purchase a 'fixed' quantity of energy from SPP-DGs but is allowed to dispatch the quantity of energy at its discretion, but at the same predetermined prices.
- **Ontario (ON) Case**: This case mimics the regulations (except for the imposed CO_2 cap and tax) that are currently practiced in Ontario and which the discos must adhere to. It is similar to the BASE case, with the exception that discos are not permitted to invest in DG capacity.

Net Present Costs

The NPCs to the LDC from capital investments and energy production cum purchase over the 10-year plan period is presented in Fig. 3.9, corresponding to the BASE case and the three other cases discussed earlier. The capital cost components within the NPC are obtained from the SPPM while the energy costs are obtained from the CPPM. The salvage component of the capital cost is the discounted value of all capital assets at the end of the study, year-10, subject to depreciation.

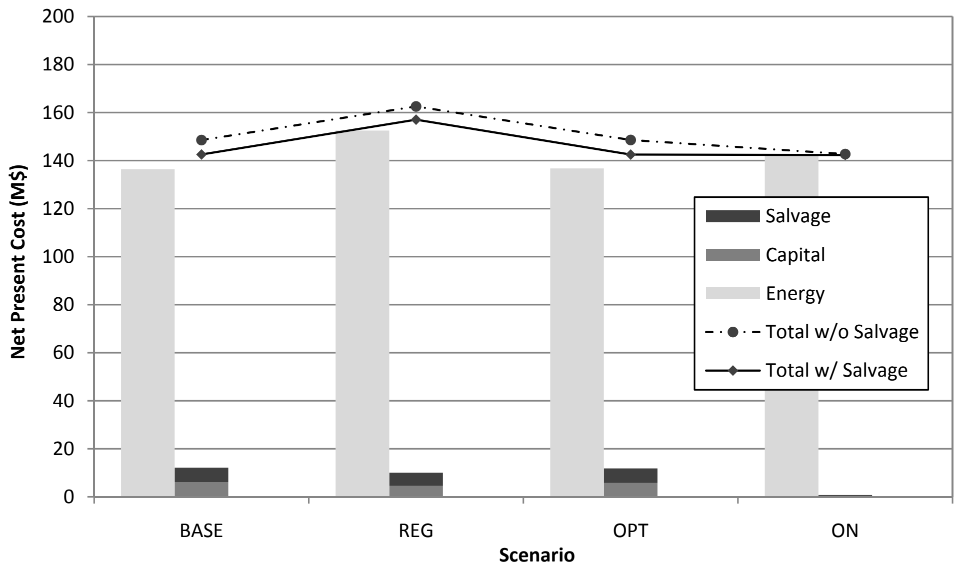

Figure 3.9: Comparison of NPCs Across Policies

It is immediately observable that the NPC from the REG case is higher than from the other three cases. This is attributable to the REG policy prohibiting the use of intertie resources, one of the cheapest sources of energy, resulting in higher energy costs and total costs. The BASE and OPT cases have identical NPCs despite the difference in dispatch rules, which leads to the conclusion that, for given system, all SPP-DG investments are a benefit to the system (as discussed in Section 3.6.2). This is attributed to the lower price of energy from SPP-DGs (compared to LDC purchased market/external grid energy) and DG unit placement at the feeder extremities.

Capital Investments

A comparison across the policy cases for the accumulated capital investments made by the LDC up to the planning horizon is presented in Table 3.15. It is observed that, when permitted to do so (in the BASE, REG, and OPT cases), the LDC should invest in DG units. The highest DG unit investments are made in the BASE and OPT cases, where the ability to export energy offsets the unused capacity of the LDC, thus justifying its increased capital outlay. Significantly less DG investments are recommended in the REG case due to the prohibition on exports to the grid.

An intertie, a relatively inexpensive source of energy, is planned for in each of the cases when allowed (BASE, OPT, and ON). In the BASE and ON case, it allows the utility to reduce its imports via substations and also frees up DG capacity for profitable export. In the REG and ON case studies, the additional substation capacity is built to meet adequacy requirements, but not used in normal operation. In the BASE and OPT cases, utility-DG (which is usually scheduled to export to the grid), can also be used to meet adequacy requirements. Only two

Table 3.15: Comparison of Capital Investments Across Policies

	Investment Size (MW) and # of Builds				
	Substation	Intertie	Gas Turbine	Wind T	Feeder
BASE	-	10.0 (1)	13.7 (4)	6.2 (2)	5.4 (2)
REG	10.0 (1)	-	6.6 (2)	6.2 (2)	3.7 (2)
OPT	-	10.0 (1)	13.7 (4)	6.2 (2)	5.4 (2)
ON	10.0 (1)	10.0 (1)	-	-	6.1 (4)

feeder segment upgrades are required in the BASE, OPT, and REG cases since feeder loading is reduced by DG units placed at feeder-ends. In the ON case, the lack of utility-DG means demand must be served from the substation (further from the load) and thus more feeder segments must be upgraded to handle increased loading.

Energy Production/Transfer Schedule

Fig. 3.10 shows the LDC's energy production, contracting, and import/export schedule aggregated over the 10-year planning period. Imports from the external grid, via substations, followed by imports via interties (where available) account for the largest share of energy under all policy cases. The energy purchased by the LDC from SPP-DG in the OPT case is identical to that in fixed dispatch scheme BASE, proving that the SPP-DG investments contribute significantly to displacement of expensive energy purchases from the grid. Exports to the grid occur in the BASE and OPT cases when it is profitable to use the available capacity (not serving demand) from DG units. In the ON case, no export is scheduled since there is no utility-DG capacity, and all other energy sources are used to offset substation purchases.

CO_2 Emissions

Total CO_2 emissions over 10 years (Fig. 3.11) are directly correlated to energy produced by SPP and utility-DG. It should be noted that CO_2 emissions from imported energy via substations and interties are neglected. This is consistent with LDC-centric planning not concerning a global emissions policy, which will be explored in Chapter 4. Since utility-DG units are not permitted in the ON case, the only contribution to emissions comes from SPP-DG. The higher CO_2 emissions in the other three cases originate from the low cost polluting gas turbines. Note that total CO_2 emissions for all policy cases are below the specified cap, therefore no tax is applied.

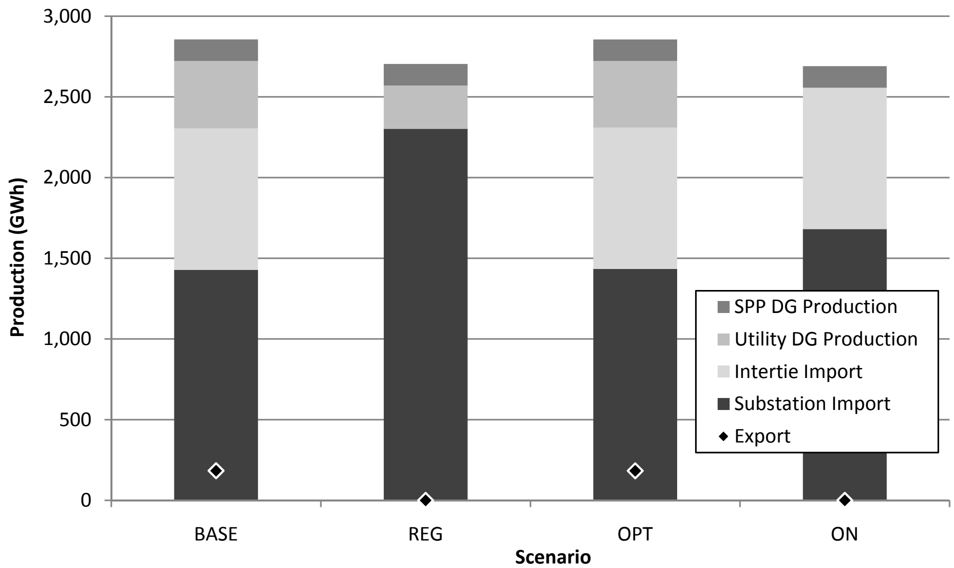

Figure 3.10: Comparison of Energy Production/Transfer Schedules Across Policies

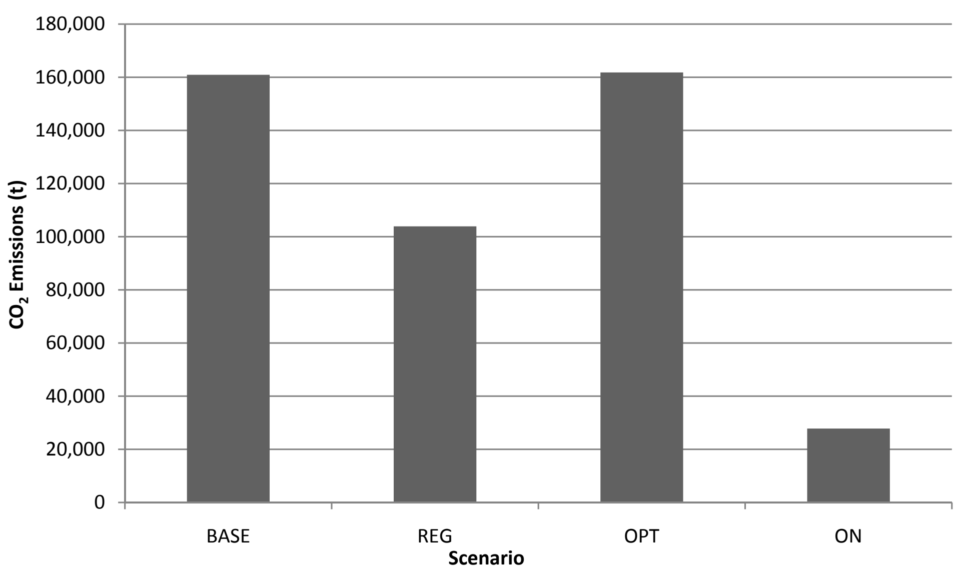

Figure 3.11: Comparison of CO_2 Emissions Across Policies

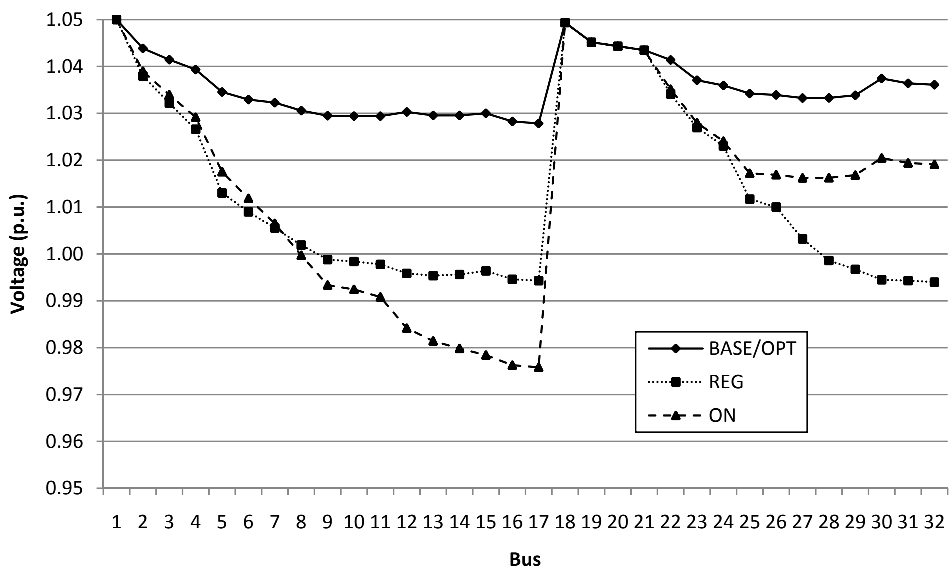

Figure 3.12: Comparison of Voltage Profiles Across Policies

Voltage Profile and Distribution Losses

The distribution system voltage profiles for each case, at year-10 during peak demand (Fig. 3.12) are within acceptable ranges because of the voltage constraints imposed in the CPPM. The cases with smaller DG investments, REG and ON, have poorer voltage profiles than the ones with higher DG support, BASE and OPT, whose units can provide voltage support at injection sites located at feeder ends.

Feeder losses in the radial distribution system (Fig. 3.13) are correlated with each case's voltage profile; cases with higher voltage profiles have lower losses. In the REG case, utility-DG units are unable to fully offset the loss increase from not being able to utilize the interties, available in the ON case. It can be concluded that, in certain cases, interties can have a greater impact on losses than DG.

3.7 Concluding Remarks

This chapter presents a comprehensive framework for distribution system planning in a deregulated environment in the presence of DG units. A sequential two-stage scheme comprising the SPPM and the CPPM are proposed. The planning framework takes into consideration various complex issues such as those arising from uncoordinated private investments in DG, and environmental emissions. The detailed plan results have been successfully demonstrated from a utility planner's and policy maker's perspective.

The proposed planning framework is generic in nature and may be used to analyze policies and their effects on LDC decisions and the resultant changes in distribution system reliability, emissions, etc. The framework has been used to examine

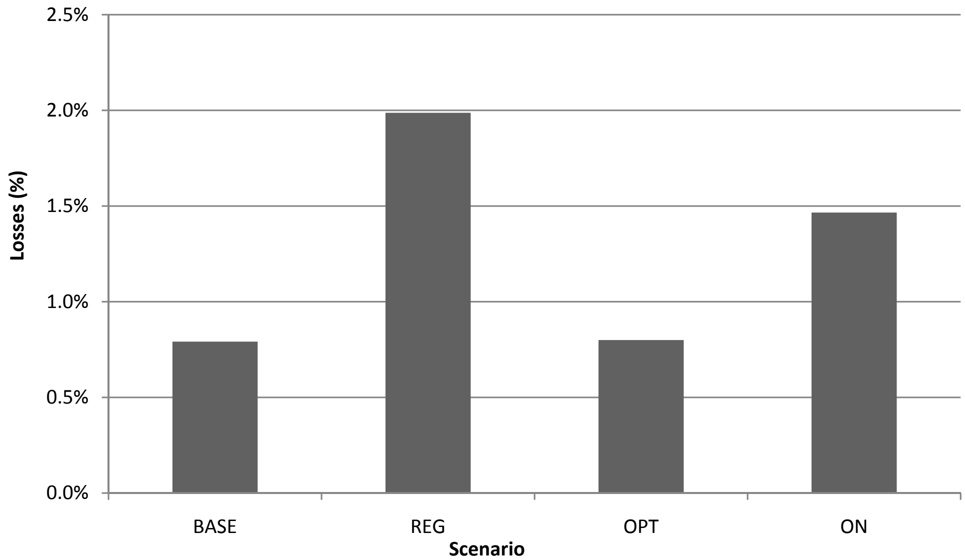

Figure 3.13: Comparison of Distribution Feeder Losses Across Policies

four typical policy scenarios in this chapter. It is found that capital investments in DG are justified by their savings in energy costs over the 10 year planning period and that, furthermore, the ability to export energy is important in determining the placement of DG. Of the DG technologies examined (diesel engines, gas turbines, wind turbines, solar-PV), gas turbines are favoured for their lower costs and wind turbines become viable once the price of gas increases beyond a certain level.

Whereas this chapter largely examines the effects of allowing DG investments, from the LDC's point of view, the next chapter examines the effects, from the regulator's standpoint, of the different incentives and policies that can be used to encourage investment in DG.

Chapter 4

Long-Term Effects of Feed-in-Tariffs and Carbon Taxes on Distribution Systems[1]

4.1 Introduction

In Chapter 3, a mathematical framework for the planning of distribution systems considering DG is presented. An analysis of the various policies related to deregulation, *i.e.* the permission of LDCs and SPPs to invest in DG, is briefly examined from the LDC's point of view. In this chapter, the focus shifts to government regulators, since controlling the penetration of DG investments is not the domain of the LDC but rather the government. This work examines the wide range of policy instruments at the disposal of the regulators, such as FITs, that can be used to meet regulatory and environmental goals with DG investments.

4.1.1 Standard Offer Program

The Integrated Power System Plan (IPSP) for Ontario [90], developed by the Ontario Power Authority (OPA) every three years, chalks out a direction of growth for the Ontario power system. The current IPSP, covering the next 20 years, emphasizes the development of clean and renewable energy sources and the phasing out of several major polluting coal-fired power plants. To achieve the former, the Standard Offer Program (SOP) [91], [92], developed by the Ontario Energy Board

[1] The work presented in this chapter has been submitted for publication, and is in revision, in S. Wong, K. Bhattacharya, and J.D. Fuller, "Long-Term Effects of Feed-in Tariffs and Carbon Taxes on Distribution Systems," *IEEE Trans. on Power Syst.*, In Revision. An earlier version of this work has been presented and appears in S. Wong, K. Bhattacharya and J.D. Fuller, "Environmental and economic analysis of Ontarios Standard Offer Program for small power producers," *Proc. IEEE PES Annual General Meeting*, Pittsburgh, USA, 2008.

(OEB) and OPA, was introduced for SPPs investing in DG units, who previously could only sell energy through net-metering.

The SOP is classified into two parts: the Clean Energy SOP (CESOP) and the Renewable Energy SOP (RESOP). CESOP [91] projects must be natural-gas CHP, by-product fuel fired, or under-utilized thermal or mechanical. RESOP [92] projects must be bio-gas, solar PV, wind, or hydro units. DG-unit investment proposals must be less than a gross capacity of 10 MW at the point of connection.

Ontario's SOP offers the SPPs set prices, fractionally indexed to inflation, for energy produced from qualified DG units over the life of the contract (20 years). Under the old (pre-2008) CESOP, SPPs receive the Hourly Ontario Energy Price (HOEP) plus an 8¢/kWh premium during peak periods and a 4¢/kWh premium during intermediate and base periods. Under the new CESOP, introduced in 2008, SPPs with CHP projects receive a contingent support payment, which is the difference between their actual net market revenue and the net revenue guarantee, as determined by the OPA [91].

SPP-DG units participating in the RESOP are paid as per their technology in place: solar-PV units receive a price of 42¢/kWh while wind-turbines receive 11.04¢/kWh plus a 3¢/kWh premium for reliable peak period generation.[2] Responsibility for payments to SPPs under the RESOP lies with the OPA and the connecting LDC: the LDC pays for energy up to the HOEP and the OPA pays the remaining amount [93]. For example, if a solar-PV based SPP produces 1 kWh of energy when the HOEP is 8¢/kWh, the LDC will pay 8¢/kWh and the OPA will pay 34¢/kWh to the SPP.

The incentives offered in the RESOP have arguably been a large success. The resultant effect of these FITs, in Ontario, has been a large volume of investment proposals from SPPs. As of February 2009, the Ontario Power Authority has secured 428 contracts with a total of 1.4 GW generating capacity: 745 MW from wind, 525 MW from solar-photovoltaic, 66 MW from hydro, and 73 MW from bio-energy sources [94]. Each of these DG investments have unit sizes of 10 MW or less.

4.1.2 Carbon Taxes and Cap-and-Trade Mechanisms

Governments attempting to reduce carbon emissions may employ penalties through carbon taxes or cap-and-trade mechanisms. With a carbon tax mechanism, a tax is imposed on a dollar per tonne of emission basis, for carbon emissions accrued by the emitter or the end user. Carbon tax mechanisms are imposed in some European countries, including Sweden (CDN$127/t [95]) and Finland. Taxes have been proposed in Canada, but as of yet have only been implemented at the provincial level, in Quebec and British Columbia (CDN$15/t (in 2009) to $30/t (in 2012) [96]).

[2] As of 2008, the RESOP is currently under revision. The proposed changes will address the competitive procurement of capacity.

Under a strict cap-and-trade mechanism, total CO_2 emissions are capped; participating entities are each allocated a set amount of allowable emissions which sum to the cap. Entities must purchase additional carbon credits, usually via an emissions credit market, to exceed their quota. They may also sell unused portions of their quota as emission credits. Under an intensity-based cap-and-trade mechanism, CO_2 emissions are capped per unit of output. For example, an SPP's CO_2 quota would be based on its energy output. They may or may not be able to sell the unused portions.

4.1.3 The Role of DG in Distribution System Planning

The penetration of DG, utility-owned or SPP-owned, into the power system has been fostered by technological progress and widespread regulatory acceptance and programs (as stated above). Furthermore, the deregulation of the power system industry has opened it up to increased supply from SPP-DG.

The impact of DG on the distribution may vary depending on ownership and regulations in place. Within Ontario, SPP-DG placement is uncoordinated (with the LDC) and up to the SPPs, so long as it is technically feasible for the LDC to integrate it. Operationally, SPP-owned DG units are not dispatchable and, as long as variable costs are recovered, they should produce at their maximum capacity. On the other hand, LDC-owned DG units can be optimally sited and sized into the distribution system, maximizing economic benefits to the LDC and its customers. Operationally, they can be dispatched (provided the technology permits) to maximize their impact and minimize costs to the system.

The push from governments and consumers to find environmentally sustainable sources of energy is further driving the penetration of DG units that are seen as clean or renewable. Clean or renewable energy DG investments may result in carbon reductions by substituting for 'dirty' energy, *e.g.* using wind or solar fueled generation to replace energy from coal-fueled bulk energy generators, as discussed in Ontario's Integrated Power System Plan [90]. Such DG investments are often the subject of additional incentives, like FITs, encouraging investment. However, the explicit impact of FITs and carbon tax or cap-and-trade schemes on DG units and planning of their host distribution system has not been formally resolved in literature.

Questions may arise as to what is the most appropriate FIT to achieve environmental and economic goals within the power system. For example, how large should the FITs be for them to be effective in attracting investments in chosen technologies to meet the long-term growth requirements of the energy sector? On a larger policy scale, it may be asked what are the implications of policies permitting LDCs to invest in DG capacity within their own distribution system network. Since the stated goals of FITs, CO_2 tax, or cap-and-trade mechanisms are to reduce CO_2 emissions, it must be examined how effective they are in achieving this goal. The cost of these instruments to the energy consumer is also a relevant question. In essence, the design and suitability of these instruments to reduce emissions must be examined.

This chapter attempts to address the above questions and issues, by

a) presenting a distribution system model that is appropriate for determining the impact of regulatory policies on DG unit investments by SPPs as well as LDCs
b) examining the impact of such investments on energy dispatch/purchase decisions
c) examining the environmental and economic effects of various regulatory policies

The discussions on the impacts and effects of a FIT in combination with a CO_2 tax or cap-and-trade mechanism are based on scenarios outcomes, over a 10 year period, using the distribution system model. The FIT policies modelled in this chapter are based in-part on those developed for Ontario by the OPA which is responsible for setting policies and securing the long-term energy needs for the province. [97]. The cap-and-trade mechanism employed is intensity based (t/MWh) to avoid necessary complications and questions that would arise from dividing the CO_2 quotas between participants (as would be required with a strict cap-and-trade mechanism.)

In Section 4.2 of this chapter, the mathematical formulation of the energy dispatch and DG investment model is presented. Section 4.3 examines and discusses the effects of various regulatory policies through the application of the model to a realistic 32-bus radial system and Section 4.4 presents the results and their analysis. Conclusions and scope for future work are presented in Section 4.5.

4.2 Mathematical Description

The mathematical model presented below determines future DG unit investments by SPPs and energy dispatch/purchase decisions by the LDC. It is assumed that SPPs are autonomous from LDCs, but their investments in DG and their consequent power injections to the LDC's system must not undermine the nodal balance constraints. This model gives a solution that is the most profitable to SPPs as a whole, a likely outcome since it can be argued that SPPs with the most to profit are likely to be the first to submit and have approved their proposals by the LDC (and locking in their production schedules).

The proposed model is a MILP model in which binary variables are used in siting DG investments.

4.2.1 Objective Function

The objective function (J_1), in (4.1), maximizes the SPPs' profits from the sale of energy from investments in DG units.

$$
\begin{aligned}
&\max J_1 = \\
&\sum_{t}^{T} \frac{1}{(1+R_k^{SPP})^t} \Bigg[\\
&\qquad \sum_{\substack{k\in K, q\in Q,\\ i\in N, b\in B}} P^{dg}_{k,q,i,b,t} Hrs_b \big(Ce^{dg}_{q,b,t} + Ce^{dg.FIT}_{q,b,t} - Co^{dg}_{q,t}\big) \text{ (a)} \\
&\qquad - \sum_{\substack{k\in K,\\ q\in q,\\ i\in N}} \Big(w^{dg}_{k,q,i,t} Cc^{dg.v}_{q,t} + z^{dg}_{k,q,i,t} Cc^{dg.f}_{q,t}\Big)(1+R_k^{SPP})(1-\alpha^{dg}_{q,t}) \text{ (b)} \\
&\qquad - \sum_{\substack{k\in K, q\in Q,\\ i\in N, b\in B}} \Big(P^{dg}_{k,q,i,b,t} Hrs_b (CO2^{dg}_q - CO2^{cap}_t) Ct^{CO_2}_t\Big) \text{ (c)} \\
&\qquad\qquad - \sum_{i\in N, b\in B} 0.001 P^x_{i,b,t} Hrs_b \Bigg] \text{ (d)}
\end{aligned}
\tag{4.1}
$$

where the salvage value (α) is found by a depreciation formula; here straight-line depreciation is used:

$$
\alpha^{dg}_{k,q,t} = \frac{1}{Ls^{dg}_q}(t + Ls^{dg}_q - H - 1)\frac{1}{(1+R_k^{SPP})^{(H-t+1)}} \quad \forall\, t + Ls^{SPP}_q \geq H \tag{4.2}
$$

else

$$
\alpha^{dg}_{k,q,t} = 0 \tag{4.3}
$$

Line (a) in (4.1), represents the SPPs' income from energy sold to the LDC including additional incentives from SOP, if applicable, net of operation and maintenance costs (discounted from the end of period t). Line (b) is the EPC costs (discounted from the beginning of period t) for DG unit investments. Salvage values, at the end of the study period, are subtracted from infrastructure costs to account for a finite study horizon. Lastly, line (c) represents the cost of emissions incurred by the SPP in the form of carbon taxes. When the emissions are less than the intensity cap, the cost is reversed and becomes an emissions credit to the SPP. Note that a CO_2 tax-only mechanism can also be put in place through line (c) by having a capacity credit of zero.

Line (d) is an imaginary cost, for the export of energy from the distribution system, used to control substation export levels. Exports are not controlled by the SPPs, but the absence of the export variable, Px, in the objective function, J_1, would cause illogical and distorted substation import and export levels; they would be uncontrolled, checked only by each other in Eq. (4.4). It should be emphasized that this cost is not incurred by SPPs nor does it have any effect on their energy dispatch or purchase decisions.

4.2.2 Nodal Power Balance

Linear network power flows (4.4) are used to represent the supply and demand balance in the distribution system. Feeder losses are approximated by a loss factor, $Ll^{fdr}_{(i,j)}$, and accounted for in the incoming power flow incident on a bus. Equations (4.5) and (4.6) ensure a unique direction to the feeder power flow. Note that, for accounting purposes, exports and imports are regarded as separate transactions.

$$\sum_{\substack{j \in N: \\ \exists (i,j)}} \big((1 - Ll^{fdr}_{(i,j)}) P^{fdr}_{(j,i),b,t} - P^{fdr}_{(i,j),b,t} \big) =$$

$$P^{x}_{i,b,t} + Pd_{i,b,t} - P^{ss}_{i,b,t} - \sum_{k \in K, q \in Q} P^{dg}_{k,q,i,b,t} \qquad \forall i \in N, b \in B, t \in T \quad (4.4)$$

$$P^{fdr}_{(i,j),b,t} \leq M z^{pf}_{(i,j),b,t} \qquad \forall i,j \in N : \exists\ (i,j) \qquad (4.5)$$

$$P^{fdr}_{(j,i),b,t} \leq M (1 - z^{pf}_{(i,j),b,t}) \qquad \forall i,j \in N : \exists\ (i,j) \qquad (4.6)$$

4.2.3 Export and Penetration Limits

System constraints limit (4.7) the quantity of energy that can be absorbed from DG units to a percentage, DG^{max}, of demand plus exports. Substation transformer limits (4.8) restrict the amount of energy that can be exported to the external grid/market. Together, these limits mimic system technical constraints not modelled here (such as feeder limits) and addresses system reliability concerns (since DG may not be seen as a reliable energy source).

$$\sum_{k,q,i} P^{dg}_{k,q,i,b,t} \leq DG^{max} \big(\sum_{i \in N} Pd_{i,b,t} + P^{x}_{i,b,t} \big) \qquad \forall b \in B, t \in T \qquad (4.7)$$

$$P^{x}_{i,b,t} \leq P^{x.max}_{i} \qquad \forall i \in N_{ss}, b \in B, t \in T \qquad (4.8)$$

4.2.4 DG Build

A SPP's DG unit, classified by technology and bus, must be less than a specified capacity (4.9) in order to qualify for the SOP. For the purpose of computations, a

DG unit is counted as one regardless of the number of capacity upgrades it may undergo. From the SPP's financial perspective, DG units must be of a minimum size (4.10) to be practical. Equation (4.11) uses a binary variable to keep track of DG units being built or upgraded, which allows for fixed capital costs to be modelled in (4.1).

$$\sum_{t'=1}^{t}(w^{dg}_{k,q,i,t}) \leq W^{dg.max}_{k,q} \qquad \forall k \in K, q \in Q, i \in N, t \in T \tag{4.9}$$

$$w^{dg}_{k,q,i,t} \geq z^{dg}_{k,q,i,t} W^{dg.min}_{k,q} \qquad \forall k \in K, q \in Q, i \in N, t \in T \tag{4.10}$$

$$w^{dg}_{k,q,i,t} \leq M z^{dg}_{k,q,i,t} \qquad \forall k \in K, q \in Q, i \in N, t \in T \tag{4.11}$$

4.2.5 DG Energy Limits

The availability factor and capacity factor of a DG unit constrains its total energy output over a specified time period. Given that typical availability factors of DG units are extremely high (disregarding fuel unavailability, a factor included in the capacity factor), it can be assumed without loss of generality that the availability factor is unity. Capacity factor, on the other hand, is primarily affected by dispatch and/or fuel availability.

Since wind speed and solar radiation levels vary considerably over the course of a day, the power generated from wind and solar-PV based DG units vary from minute to minute. In order to incorporate the energy generated from such wind and solar-PV units as a variable in long-term models, an average capacity factor is used. Generation from DG units may also vary by location. Annual locational capacity factors, segregated by peak, intermediate and base load levels, can be estimated based on operator experience. These ECFs are used to specify the generation levels from wind and solar-PV DG units in (4.12).

$$P^{dg}_{k,q,i,b,t} Hrs_b = ECF_{q,i,b} \sum_{t'=1}^{t}(w^{dg}_{k,q,i,t}) Hrs_b \qquad \forall k \in K, q \in Q^{nd}, i \in N, b \in B, t \in T \tag{4.12}$$

For dispatchable DG units, the capacity factor is used as an upper limit on energy generation during a certain load block (4.13). Unless constrained by system limits, energy generated by SPP-DG units, either dispatchable or non-dispatchable, is always accepted by the LDC. This is akin to the existing policy in Ontario.

$$P^{dg}_{k,q,i,b,t} Hrs_b \leq ECF_{q,i,b} \sum_{t'=1}^{t}(W^{dg}_{k,q,i,t}) Hrs_b \qquad \forall k \in K, q \in Q^{d}, i \in N, b \in B, t \in T \tag{4.13}$$

4.2.6 Variable Signs

Variables $P^{fdr}_{(i,j),b,t}$, $P^{dg}_{k,q,i,b,t}$, $P^{ss}_{i,b,t}$, $P^{x}_{i,b,t}$, and $w^{dg}_{k,q,i,t}$ are positive; $z^{dg}_{k,q,i,t}$ and $z^{pf}_{(i,j),b,t}$ are binary.

4.2.7 Special Cases Permitting LDC Owned and Operated DG

The objective function, J_1 of (4.1), assumes that only SPPs may build and operate/dispatch DG units (as in Ontario). However, in some systems this may not hold and SPP participation may not be permitted. In such a situation the LDC may build and operate its own DG units, and will do so in a manner to minimize its overall costs. To simulate this case, the objective function, J_2, is now formulated as the minimization of the LDC's total costs (4.14). The constraints (4.4) to (4.13) are still present, except that all references to SPPs are to be replaced by LDC.[3] Note that SOP incentives are not available to the LDC, since it is assumed that the LDC can achieve additional benefits from tighter integration that would make up for this loss.

$$
\begin{aligned}
\min J_2 = & \\
& \sum_{t}^{T} \frac{1}{(1+R^{LDC})^t} \Bigg[\sum_{\substack{q\in Q,\\ i\in N, b\in B}} P^{dg}_{q,i,b,t} Hrs_b \big(Co^{dg}_{q,t}\big) \text{ (a)} \\
& + \sum_{q\in q, i\in N} \Big(q^{dg}_{q,i,t} Cc^{dg.v}_{q,t} + z^{dg}_{q,i,t} Cc^{dg.f}_{q,t} \Big)(1+R^{LDC})(1-\alpha^{dg}_{q,t}) \text{ (b)} \\
& + \sum_{i\in S, b\in B} \Big((P^{ss}_{i,b,t} - P^{x}_{i,b,t}) Hrs_b Ce^{ss}_{b,t} \Big) \text{ (c)} \\
& + \sum_{\substack{k\in K, q\in Q,\\ i\in N, b\in B}} \Big(P^{dg}_{k,q,i,b,t} Hrs_b (CO2^{dg}_q - CO2^{cap}_t) Ct^{CO_2}_t \Big) \text{ (d)} \\
& + \sum_{i\in S, b\in B} \Big(P^{ss}_{i,b,t} Hrs_b (CO2^{ss} - CO2^{cap}_t) C^{CO_2}_t \Big) \Bigg] \text{ (e)}
\end{aligned}
\tag{4.14}
$$

[3] This model neglects the LDC's substation and/or feeder costs, which are regarded as pre-existing and thus sunk costs.

where the salvage value (α) is found by a depreciation formula; here straight-line depreciation is used:

$$\alpha_{q,t}^{dg} = \frac{1}{Ls_q^{dg}}(t + Ls_q^{dg} - H - 1)\frac{1}{(1+R^d)^{(H-t+1)}} \qquad \forall\ t + Ls_q^{dg} \geq H \tag{4.15}$$

else

$$\alpha_{q,t}^{dg} = 0 \tag{4.16}$$

Line a in (4.14), represents the operation and maintenance costs for DG units. Line b represents the capital and EPC costs for DG unit investments. Line c represents the cost to the LDC for purchasing and importing energy from the market/external grid, via substations, net of income it receives from selling energy to the market/external grid, via substations. Lines d and e represent the cost of emissions incurred by the LDC in the form of carbon taxes.[4] Similar to c of (4.1), these terms may become emission credits if emission levels are lower than the emission cap.

4.3 Case Studies

To examine the effects of FITs (*i.e.*, the SOP of Ontario) and carbon taxes on DG investments in distribution systems, the two mathematical models of Section 4.2 are applied to a 32-bus radial distribution system. A 10-year planning period is used for all the studies.

4.3.1 32-Bus Radial Distribution System

The test distribution system, Figure 4.1, consists of 32 buses in radial configuration. Its electrical characteristics, including topology and active power demands, are reproduced from [86]. The distribution system's parameters are given in Table 4.1. The line loss, Ll, of 1.2% per segment corresponds to a system-wide gross distribution loss of 8%.

4.3.2 LDC and SPP Parameters

The LDC's parameters are given in Table 4.2. The value of $CO2^{ss}$ is the average CO_2 emissions from Ontario's bulk electric system per unit of energy generated [98].

[4] In reality, CO_2 emissions taxes would apply not to the LDC but to the bulk generators supplying the LDC. However, estimating the effect that CO_2 taxes would have on $Ce_{b,t}^{ss}$ would be difficult, and require a model far beyond what is done here. Instead, a rough approximation of this effect is used.

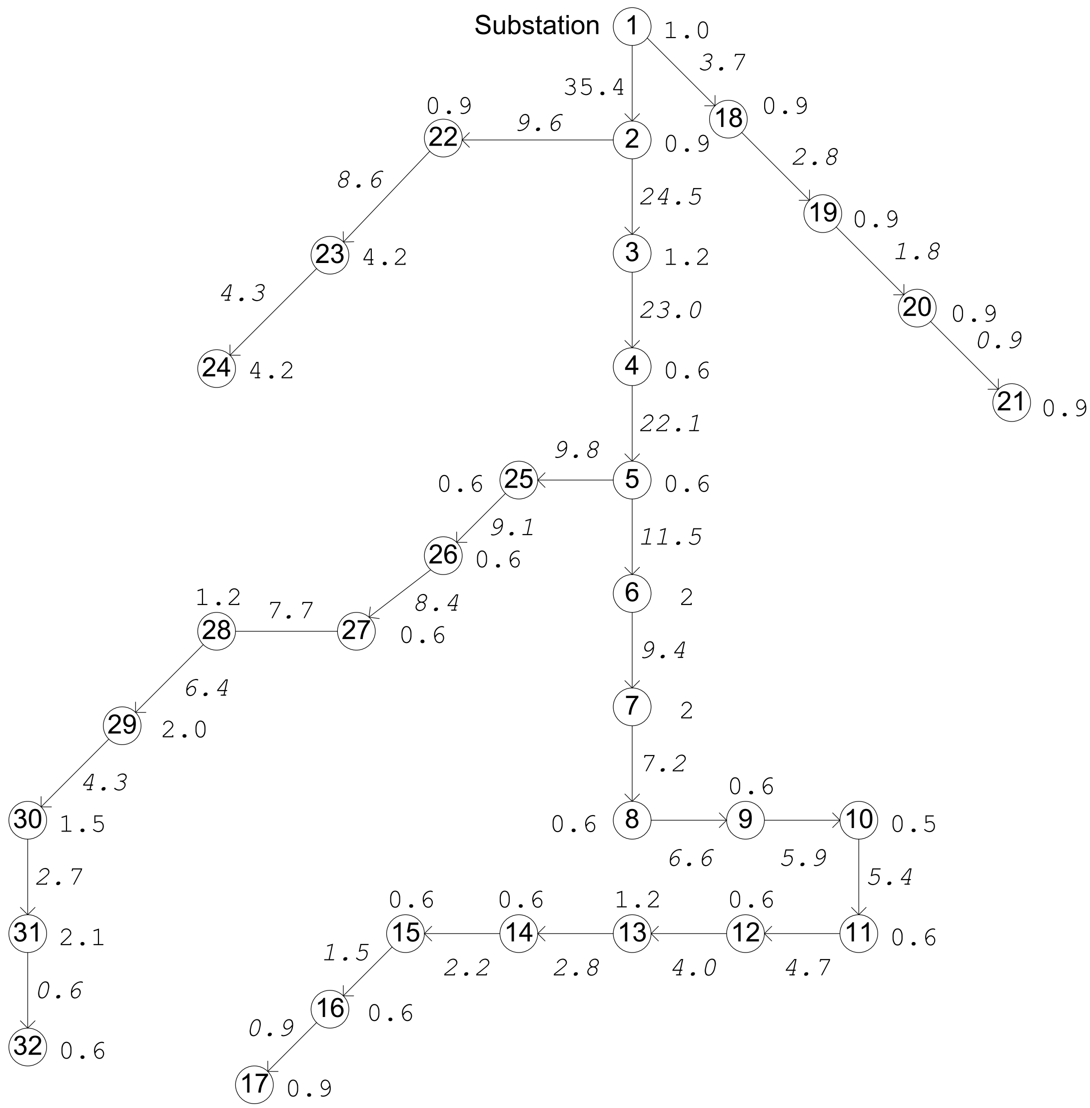

Figure 4.1: 32-Bus Radial Distribution System: Year-0 Loads and Power Flows (*Italicized*)

Table 4.1: 32-Bus Distribution System Parameters

Horizon, H	10 years
Hours in year, Hrs_b	Base: 4380; Intm: 3504; Peak: 876
Est. feeder loss, Ll	1.2% per segment
Yr-0 demand, P_d (MW)	Base: 18.58; Intm: 31.58; Peak: 37.15
Growth in P_d	3% per year, uniform across all loads

Table 4.2: LDC Parameters

Market price of energy, Ce_b^{ss}	Base: 55¢/kWh
	Intm: 72¢/kWh
	Peak: 90¢/kWh
CO_2 from bulk generation, $CO2^{ss}$	0.2599t/MWh
Max. DG penetration, DG^{max}	20%
SS export capacity, $P^{x.max}$	10 MW
LDC's discount rate, R^{LDC}	8%

In Table 4.3, various technology options for SPP investments in DG and their associated cost, emission, and other related parameters are given [9], [10], [11]. ECFs were selected arbitrarily but within commonly accepted ranges for a typical location within Ontario. It should be noted that the ECFs reported for wind and solar-PV DG in Table 4.3 are maximum values. Since the ECFs of both wind and solar-PV DG are locational-based, the actual ECF used in the study may be lower at a bus. The market and RESOP rates are those currently in effect within Ontario. CESOP rates are based on pre-2008 data.

4.3.3 Cases

Three base cases (1, 2, and 3) are constructed in order to examine various policy issues pertaining to the long-term impact of FITs and carbon taxes on DG investments in distribution systems. These are summarized below.

- Case-1 represents a *SPP-inclusive environment* in which SPPs can invest in DG units and sell energy to the LDC at the market price.
- Case-2 represents a *SPP-friendly environment* in which SPPs are encouraged to invest in DG units and a SOP is offered to those who sell their energy to the LDC.
- Case-3 represents a tightly regulated distribution system in which the LDC is the only entity who can invest and operate DG units; there is no SPP participation.

In Cases-1 and 2, the LDC must accept all DG-sourced energy from SPPs (fixed output), whereas in Case-3 the LDC may dispatch DG units (where technology permits).

Each base case also considers two sub-cases that examine the effects of employing a carbon tax or intensity-based cap-and-trade mechanism. The first sub-case, T, considers the government imposing a tax of \$50/t on all carbon emissions ($CO2_t^{cap} = 0$). The second sub-case, CT, considers the government imposing a cap-and-trade system which requires participants, the LDC or SPPs, to pay for carbon emissions

Table 4.3: SPP Parameters [9], [10], [11]

	Diesel Engine	Natural Gas Turbine - CHP	Solar PV	Wind Turbine
R_k^{LDC}	15%	$\rightarrow$	$\rightarrow$	15%
$Cc^{f.dg}$	\$50k	\$50k	\$100k	\$100k
$Cc^{v.dg}$	\$500k	\$400k	\$7500k	\$2000k
Change in $Cc^{v.dg}$	-	-	-4%/year	-1%/year
Ce_{Base}^{dg}	\$55/MWh	$\rightarrow$	$\rightarrow$	\$55/MWh
Ce_{Intm}^{dg}	\$72/MWh	$\rightarrow$	$\rightarrow$	\$72/MWh
Ce_{Peak}^{dg}	\$90/MWh	$\rightarrow$	$\rightarrow$	\$90/MWh
$Ce_{Base}^{dg.SOP}$	-	\$40/MWh	\$365/MWh	\$54.0/MWh
$Ce_{Intm}^{dg.SOP}$	-	\$40/MWh	\$348/MWh	\$38.4/MWh
$Ce_{Peak}^{dg.SOP}$	-	\$80/MWh	\$330/MWh	\$20.4/MWh
Co^{dg}	\$90/MWh	\$75/MWh	\$4/MWh	\$10/MWh
$CO2^{dg}$	0.65t/MWh	0.36t/MWh	-	-
ECF_{Base}	0.92	0.92	0.05	0.40
ECF_{Intm}	0.92	0.92	0.20	0.30
ECF_{Peak}	0.92	0.92	0.25	0.20
Ls	20 years	20 years	30 years	25 years
$W^{dg.min}$	0.5 MW	$\rightarrow$	$\rightarrow$	0.5 MW
$W^{dg.max}$	10 MW	$\rightarrow$	$\rightarrow$	10 MW

Table 4.4: Case Studies

Case	Objective		SOP	DG Output[1]		C^{CO_2}	$CO2^{cap}$
	$J1$	$J2$		Fixed	Dispatched		
1	✓	-	-	✓	-	-	-
2	✓	-	✓	✓	-	-	-
3	-	✓	-	-	✓	-	-
1T	✓	-	-	✓	-	\$50/t	-
1CT	✓	-	-	✓	-	\$50/t	0.1t/MWh
2T	✓	-	✓	✓	-	\$50/t	-
2CT	✓	-	✓	✓	-	\$50/t	0.1t/MWh
3T	-	✓	-	-	✓	\$50/t	-
3CT	-	✓	-	-	✓	\$50/t	0.1t/MWh

[1]: For dispatchable DG; otherwise dispatch is fixed

Table 4.5: Description of Scenarios

Scenario A:	Includes Case-1, 2, and 3.
Scenario B:	Includes Case-1T, 1CT, 2T, 2CT, 3T, and 3CT.
Scenario C:	C^{CO_2} in Case-2T is varied from \$10/t to \$110/t.
Scenario D:	C^{CO_2} in Case-2CT is varied from \$10/t to \$110/t.

over and above its 0.1 tonne per MWh allocation ($CO2_t^{cap} > 0$). This case assumes that the market has set the price of carbon credits at \$50/t. If a participant emits less carbon than its allocation, it will also receive \$50/t. The nine cases are summarized in Table 4.4.

Furthermore, there are four scenarios studied in this chapter as summarized in Table 4.5. Scenario A consists of the cases 1, 2, and 3, as discussed above. Scenario B consists of cases 1T, 1CT, 2T, 2CT, 3T, and 3CT, also discussed above. Scenario C is an extension of Case-2T, but considers multiple levels of carbon taxes that may be set by the government, from \$10/t to \$110/t, in increments of \$20/t. The wide-range considered here reflects the range seen in real-world implementation.

Unlike carbon costs associated with a carbon-tax mechanism, it should be emphasized that carbon credit prices in a cap-and-trade mechanism are not set by government or regulatory agencies but by market forces. Scenario D considers that there may be uncertainty in the carbon credit price market and that a wide range of prices might be experienced. To examine the different effects from different market conditions, the carbon credit price in Case-2CT is varied from \$10/t to \$110/t, in increments of \$20/t.

Table 4.6: Model Statistics

Single Equations	19,589
Single Variables	11,461
Discrete Variables	3,414
Resource Usage Min/Max/Avg (s)	3.9/58.6/15.2
Relative Gap Min/Max/Avg (%)	0.1/1.0/0.7

4.3.4 Computational Details

The considered test system was programmed and executed in the GAMS environment [89], using CPLEX, on an IBM eServer xSeries 460 with 8 Intel Xeon 2.8 Ghz processors and 3 GB (effective) of RAM. The model and solver statistics, including minimum, maximum, and average resource usages and relative gaps for all cases and sub-cases, are given in Table 4.6.

4.4 Results

The results of the case studies presented in this section illustrate the impact of the policy sets on DG unit investment, energy purchase and dispatch, carbon emissions, LDC costs and SPP revenues.

4.4.1 Observations from Scenario A

DG Unit Investments

SPP or LDC investments in DG capacity accrued over a 10 year period, for each case in Scenario A, are given in Figure 4.2. The optimal set of DG investments obtained for Cases-1, 2, and 3 are given in Table 4.7. Case-1 recommends that the SPP invest in 17.5 MW of wind DG capacity between year-5 and 10, but none in the earlier years, which implies wind DG capital costs are too high to support investments in the near term (*i.e.* first 4 years). As capital costs reduce due to advancements in technology, as modelled in this study, wind DG becomes a feasible option to SPPs without additional incentives.

The non-selection of investments in CHP and solar-PV DG units in Case-1 indicates insufficient income or prohibitively high costs of these technologies to render them profitable. While capital cost is the main barrier to solar-PV investment, high operating costs from fuel prices are the main barrier for CHP investment.

Case-2, which is an *SPP-friendly environment*, recommends that 9.1 MW of CHP and 6.4 MW of wind DG unit investments be made by the SPP in the first

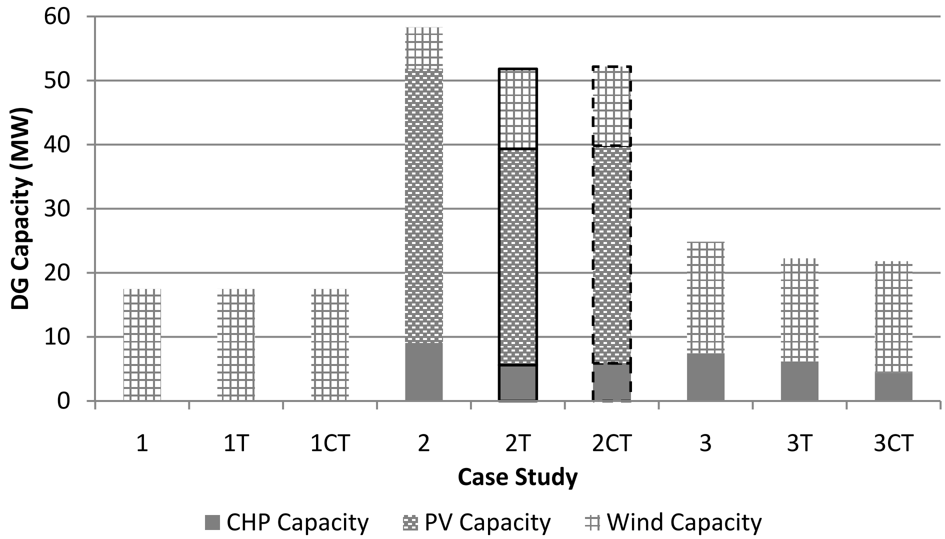

Figure 4.2: Scenario A and B: Total DG Unit Investments

year, followed by a large investment of 43 MW in solar-PV units spread over years 5 to 10 as additional capacity arises because of increasing energy demand. Clearly, in comparison to Case-1, the implementation of a FIT at levels set by Ontario's SOP is a good incentive to encourage SPP investments in both CHP and wind DG technology. Conversely, the late investment in solar-PV DG units indicate that the FIT is not sufficient to offset the high capital costs of solar-PV technology in the near-term, *i.e.* in years 1 to 4. However, as advancements in solar-PV technology lowers its cost, it will become the preferred alternative.

Case-3, representing a tightly regulated system, recommends that the LDC invests in 4.8 MW of CHP and 10 MW of wind DG units in the first year. This is followed by small, additional DG unit investments in both CHP and wind units as need for additional capacity arises because of increasing energy demand. It is evident that both CHP and wind DG investments are the preferred options compared to energy purchased from the external grid. It should be noted that there are no investments in solar-PV units, which can be attributed to their high capital costs. Also note that total investments are lower than in Case-2, because it is not financially sensible for the LDC to invest in the same way as an SPP since it does not receive SOP incentives and cannot fully make up for the additional DG capital costs by selling its energy to the grid.

Note that diesel engines are not installed by either the LDC or SPP in any of the scenarios or cases because the cost and CO_2 emissions parameters in Table 4.3 make diesel more costly than CHP.

Table 4.7: Annual DG Unit Investments

	Case 1			Case 2			Case 3		
Year	CHP	PV	Wind	CHP	PV	Wind	CHP	PV	Wind
1	-	-	-	9.1	-	6.4	4.8	-	10
2	-	-	-	-	-	-	-	-	4.6
3	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-
5	-	-	10	-	3.8	-	-	-	-
6	-	-	6.1	-	34.2	-	0.5	-	-
7	-	-	-	-	1.1	-	0.7	-	0.5
8	-	-	0.7	-	1.2	-	0.5	-	1.1
9	-	-	-	-	1.2	-	1.0	-	-
10	-	-	0.7	-	1.2	-	-	-	1.2

Energy Transactions

Energy imported and exported via the substation and energy generated by DG units, accrued over 10 years, is given in Fig. 4.3. From an accounting perspective, these are counted separately, but physically, exports offset imports. In Case-1, energy generation from DG units is limited by the marginal, later-period wind investments. In this and all other cases, energy is exported by the LDC to increase capacity for DG investments, as reflected in Eq. (4.7). The increase in DG production, in Case-2 compared to Case-1, is due to the SPP's larger and earlier investments in DG capacity. The increase in exports permit the LDC to accommodate greater capacities of DG, which is supported by an increase in imports. In Case-3, generation from DG units and exports fall slightly compared to Case-2, reflecting the decrease in installed DG capacity.

Reduction in Carbon Emissions

The reduction in carbon emissions for each case over a 10-year period, given in Fig. 4.4, is measured against a benchmark distribution system which meets its energy demand solely through energy imported from the external grid/market. Average emissions intensity for the energy used to meet distribution system demand is also given in the same figure. Note that since exported energy is not consumed within the distribution system, the carbon emissions associated with it are not included in this measurement and are subtracted at the same rate as average emissions from the bulk electric system.

It is observed that there is an 11% reduction in carbon emissions in Case-1 while when SOP incentives are introduced in Case-2, to encourage investments in

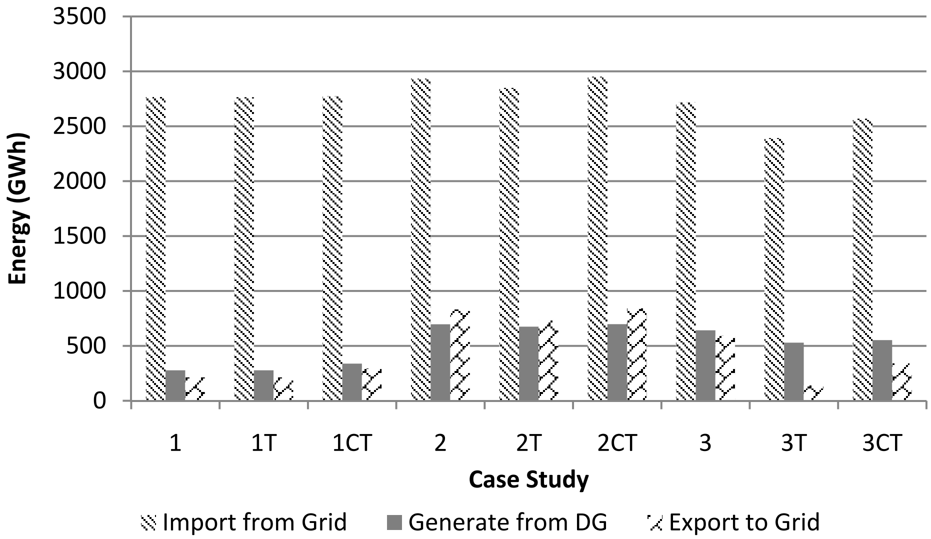

Figure 4.3: Scenario A and B: Energy Imports, Exports, and DG Production

clean energy sources, emissions are reduced by only an additional 2.5 percentage points, to 13.5%. The emissions reduction in Case-2 over Case-1 is only marginal in spite of the SOP because Case-2 emissions are tempered by the large CHP investments in year-1. As given in Table 4.2, the external grid sourced energy has an emission coefficient, CO_2^{ss}, of 0.2599t/MWh. Given the large monetary committment involved in encouraging DG, it can be concluded that the SOP is not very efficient in reducing emissions.

At 16%, the emissions reduction in Case-3 is the largest of the three cases. Compared to Case-2, there is lesser investment in carbon emitting CHP and greater investment in wind, hence the larger offset in emissions. It may thus be concluded that tight integration between the LDC and DG capacity investments may yield best results in reducing emissions.

Costs and Revenues

LDC cost, SPP profit, and the consumer's actual cost of electricity (COE, in ¢/kWh) for each case in Scenario A over a 10-year period is presented in Figure 4.5. Without loss of generality, the SOP's costs in Case-2 are incurred entirely by the LDC. It is also counted in the actual COE because it is paid by consumers (via the government).

In Case-1, the SPP's profit is negligible compared to the LDC's cost. As discussed earlier, wind is the only DG technology that is financially feasible to the SPP, but only in later years as its capital price drops, so the small profit is expected. The COE, 7.3¢/kWh, encompasses only the market price for energy (from the external grid and DG units) since there is no SOP.

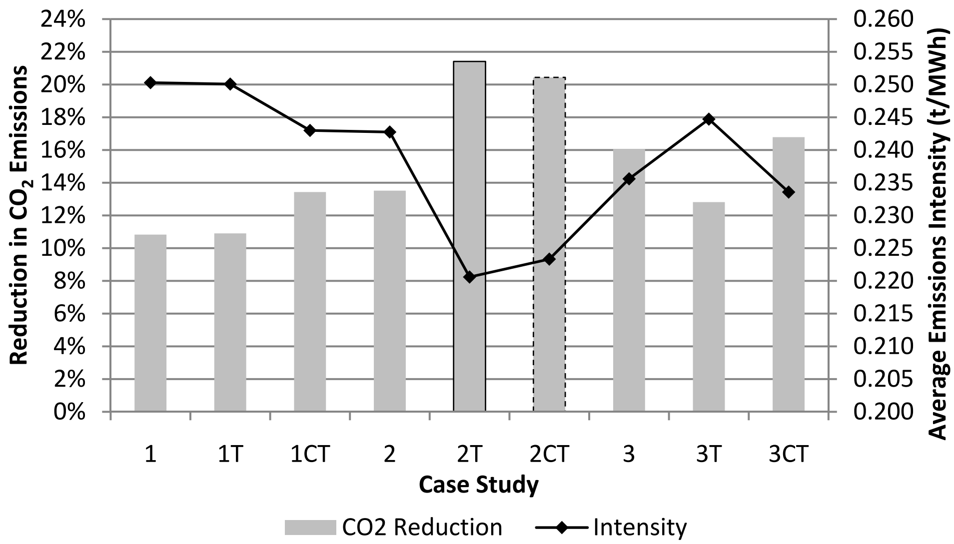

Figure 4.4: Scenario A and B: Reduction in CO_2 Emissions

The SOP, implemented in Case-2, is successful in raising the SPP's profits, which can be attributed to investment in technologies supported by the SOP: CHP, wind, and solar-PV. However, it comes at a significant cost to the LDC, raising its costs by 45% above its Case-1 cost. Accordingly, the COE rises to 10.9¢/kWh, an increase of 50%. The SOP is the source of these increased costs, especially the incentives paid to solar-PV units. Case-3 has the lowest COE, 7.2¢/kWh, which clearly demonstrates the financial benefit to the LDC and consumers by allowing the LDC to make DG investments: clean or renewable energy investments at low cost to the consumer. Instead of relying on FITs to financially encourage DG investments (Case-2), the financial incentives in Case-3 come from decreased dependence on power imports from the external grid resulting in overall savings to the LDC and the consumer.

4.4.2 Observations from Scenario B

DG Unit Investments

Total DG investments in Case-1 are not affected by either a carbon tax (Case-1T) or a cap-and-trade mechanism (Case-1CT), as seen in Fig. 4.2, since Case-1 optimal investments are all wind DG units. However, emission credits permit earlier commissioning times of wind DG investments in Case-1CT compared to Case-1.

It is observed that inclusion of either of the two carbon reduction mechanisms to Case-2 reduces investment capacity in CHP by 3 MW and solar-PV by 9 MW, and increases wind capacity by 6 MW. The reason behind the reduced CHP investment is clear: in light of the added costs to carbon emissions, CHP becomes a less viable technology. The reduction in solar-PV capacity is slightly more complex. In Case-

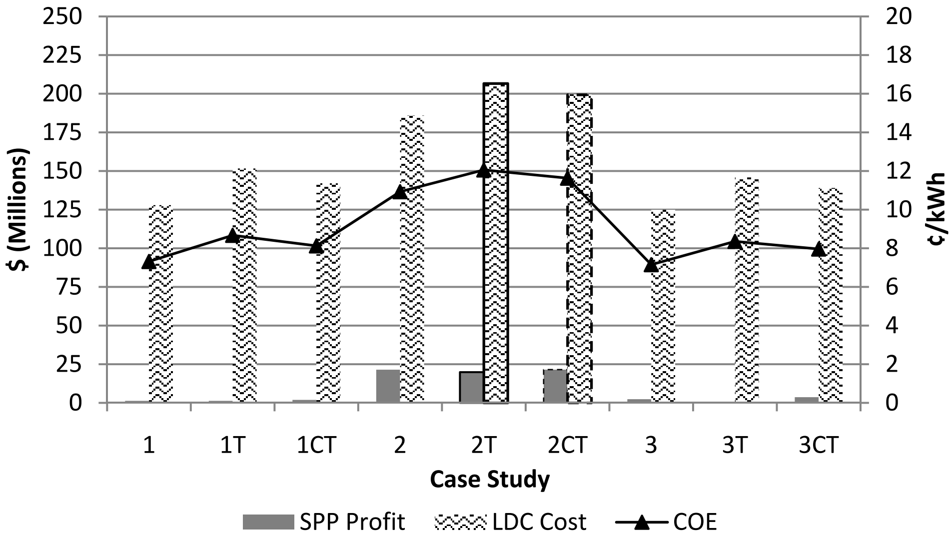

Figure 4.5: Scenario A and B: Costs and Revenues

2, solar-PV is installed in year-5 and 6, displacing energy produced by CHP units (*i.e.* CHP is not used to its full capacity after year-5.) When investment in CHP drops in Case-2T and 2CT due to additional operational costs from carbon taxes, so does the quantity of energy that solar-PV can displace, therefore its production level falls and its installed capacity falls to match. This drop in both CHP and solar-PV capacity opens more room for wind capacity, thus its installed capacity increases.

Adding a carbon tax mechanism to Case-3, Case-3T, results in 1.3 MW less investment in both CHP and wind DG units. Like above, the mechanism behind this reduction is complex. In Case-3, some room is made for capacity investments by exporting of energy, as seen in Fig. 4.3. Adding a carbon tax to CHP investments make exporting its energy less viable, leading to a fall in exports. Since allowable penetration of DG energy is a function of exports, Eq. (4.7), capacity for DG also drops, hence lowering the investments in wind capacity. It can be concluded that the cost of wind DG produced energy is low enough to justify using it to offset LDC imports, but not low enough to justify using it to increase exports. From Case-3T to Case-3CT, the 2 MW drop in investment of CHP DG and increase by 1.3 MW of wind capacity is justified by gains the LDC makes by selling its emissions credits. Essentially, these credits now makes it financially advantageous for wind investment to replace the CHP capacity that was lost.

Energy Transactions

As seen in Fig. 4.3, there are no changes in energy transactions between Case-1 and 1T (because of identical investment plans). DG production does increase very slightly in 1CT due to the SPP's earlier investment in wind capacity, which gives it two years worth of extra production. In Case-2T, imports, DG unit production, and exports decline slightly from Case-2 due to decreased investment in DG technology (discussed earlier). In Case-2CT, imports, exports, and production rise slightly compared to 2T due to small increases in investment capacity. Finally, the drop in imports, exports, and production in Case-3T and 3CT are related to changes to the mix of DG investments.

Reduction in Carbon Emissions

There are no changes in carbon emissions between Case-1 and 1T (because of identical investment plans). The reduction in emissions (Fig. 4.4) in Case-1CT by an additional 2 percentage points can be attributed to the wind DG's earlier installation. The large increase in reductions observed in Case 2T and 2CT is a result of reduced CHP and increased wind investment and production. The drop in emissions reduction in Case-3T, compared to 3, is due to decreased wind investment. However, this reduction is recovered in 3CT as investment in carbon emitting CHP falls and production from wind investment increases, offsetting emissions from bulk generation.

Costs and Revenues

Imposing either the carbon tax or cap-and-trade mechanism to any of the three case studies increases both the LDC's cost and the average COE (refer to Case-1T, 1CT, 2T, 2CT, 3T, and 3CT in Fig. 4.5). This cost increase is due to the LDC's dependence on bulk generation (imports from the grid), which is a polluting entity. The effect of taxes on Case-2T and 3T's costs is moderated, a little, by the system having a larger composition of its energy demands met by renewable energy. A cap-and-trade mechanism, in Case-1CT, 2CT, and 3CT, tempers the effect of a strict carbon tax, reducing the average COE and LDC costs. Both the LDC and SPPs make full use of the cap: in the LDC's case, to reduce costs to the consumers and the average COE, and in the SPP's case, to increase the profit of investments.

4.4.3 Observations from Scenario C

Scenario C varies the government imposed carbon tax in Case-2T from \$10/t to \$110/t. As observed in Fig. 4.6, investment in CHP capacity drops slowly as the carbon tax increases, with a significant drop between \$70/t and \$90/t. Unlike CHP capacity, the carbon tax rate does not affect the investment schedules of the other DG units, since their carbon free energy is unaffected by a carbon tax.

Carbon emissions (Fig. 4.7) fall roughly 0.2 percentage points for every \$10/t increase of the carbon tax. It also increases, in a fairly linear manner, LDC costs and the average COE (Fig. 4.8) by \$0.5M and 0.3¢/kWh per \$10/t, respectively.

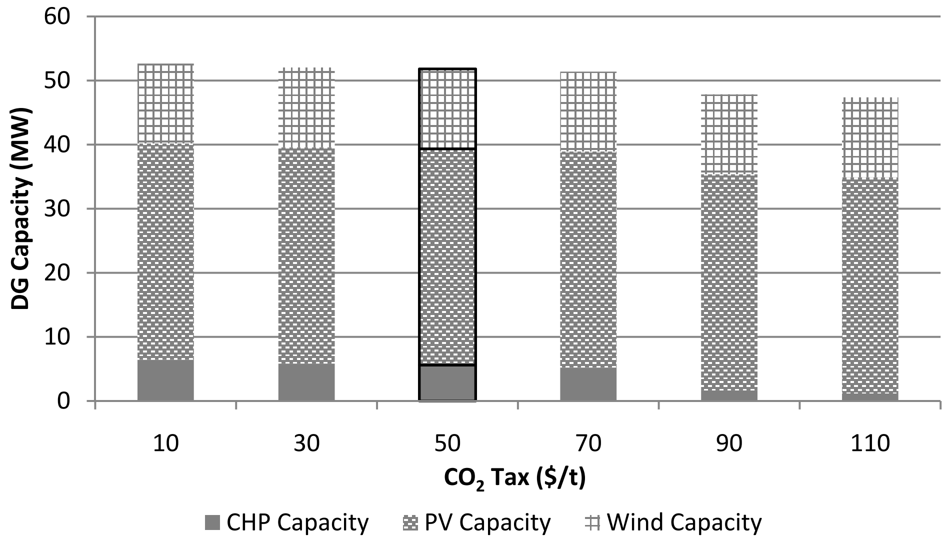

Figure 4.6: Scenario C: Total DG Unit Investments

SPP profit falls very marginally, less than $0.5M, for each $10/t increase in tax, as it takes away at income from carbon emitting CHP.

4.4.4 Observations from Scenario D

In Scenario D, the cost of carbon credits in Case-2CT is varied from $10/t to $110/t, reflecting uncertainty in the carbon credit markets. Similar to Scenario C and due to the same mechanisms, as the cost of emissions increases there is no change in investment to solar-PV or wind capacity, but progressively lower capacities of CHP investment (Fig. 4.9). Consistent with the drop in CHP investment, emissions also falls gradually from 20% to 22% (Fig. 4.10). (The slight increase at $50/t is from a very slight increase in CHP investment at that point.) The cost to the LDC increases as it must purchase carbon credits to cover the emissions tied to its imports of energy from bulk generation (Fig. 4.11). Similarly, the average COE increases from 10.7¢/kWh to 12.4¢/kWh, or 0.17¢per $10/t increase. Note that both the LDC costs and average COE are less than that for Scenario C, due to the capacity credit given to the LDC. There is no impact on the SPP's profit since additional costs due to emissions from CHP are offset by lower CHP investment and capacity credits from its wind and solar-PV units.

4.4.5 Sensitivity of Results

The parameters of the case studies presented in Section 4.3 represent a 'typical' Ontario distribution system. They are realistic but not exact. Since these parameters may vary over time, location, and between different stakeholders, a few comments are made below on the sensitivity of the results to these parameters.

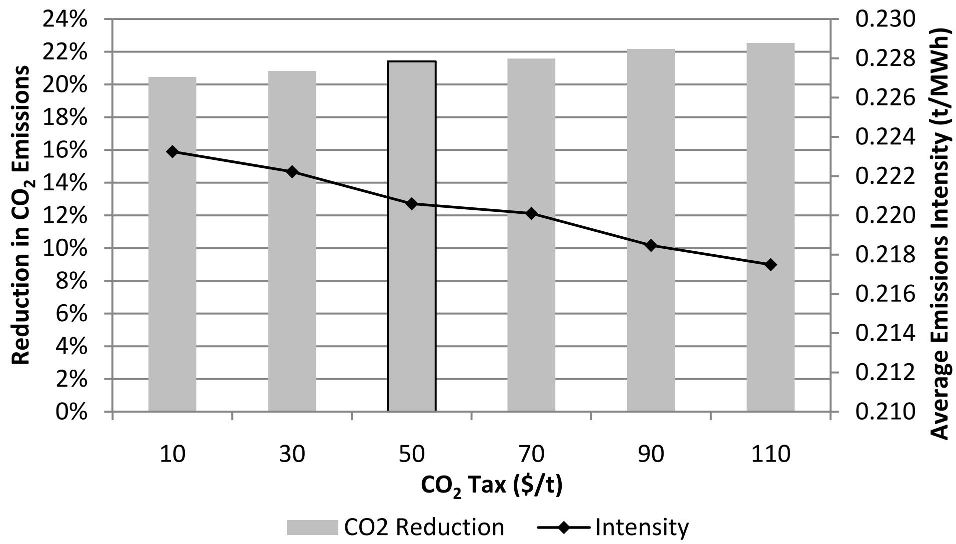

Figure 4.7: Scenario C: Reduction in CO_2 Emissions

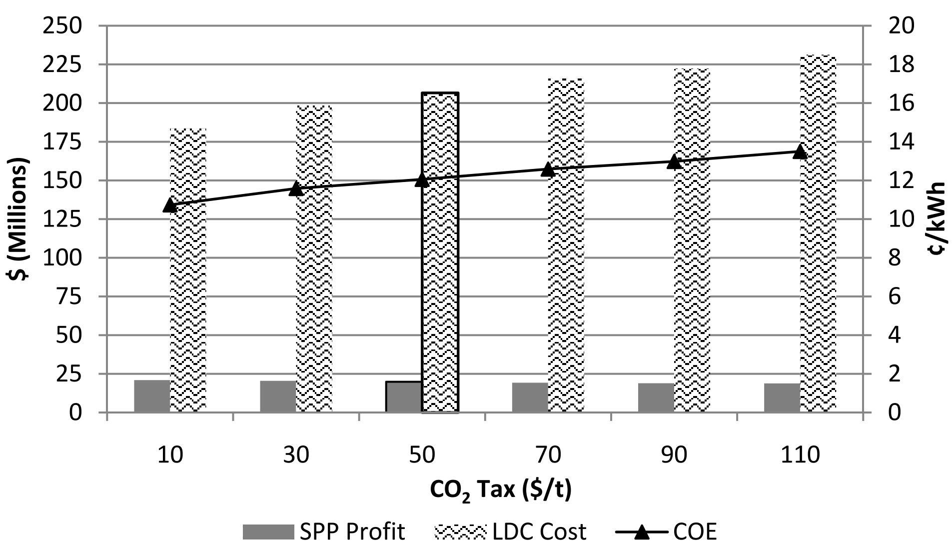

Figure 4.8: Scenario C: Costs and Revenues

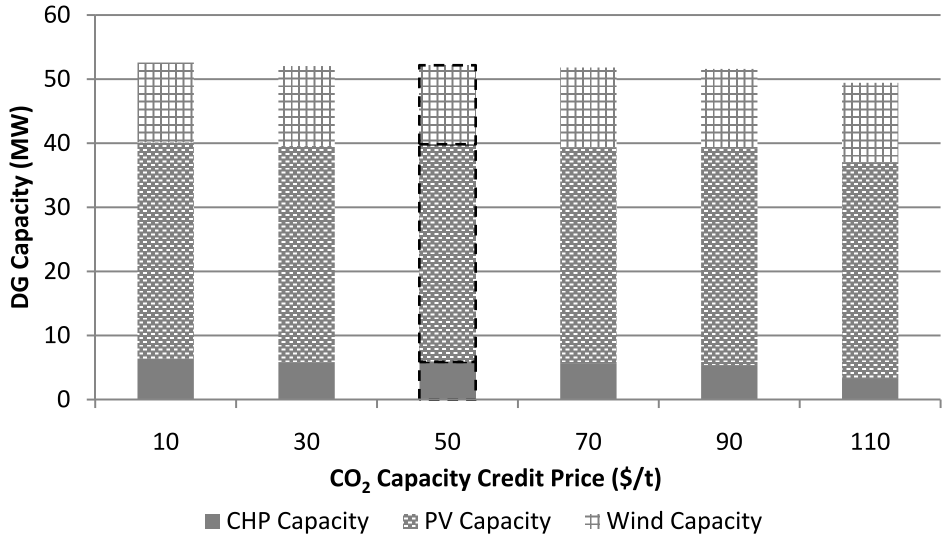

Figure 4.9: Scenario D: Total DG Unit Investments

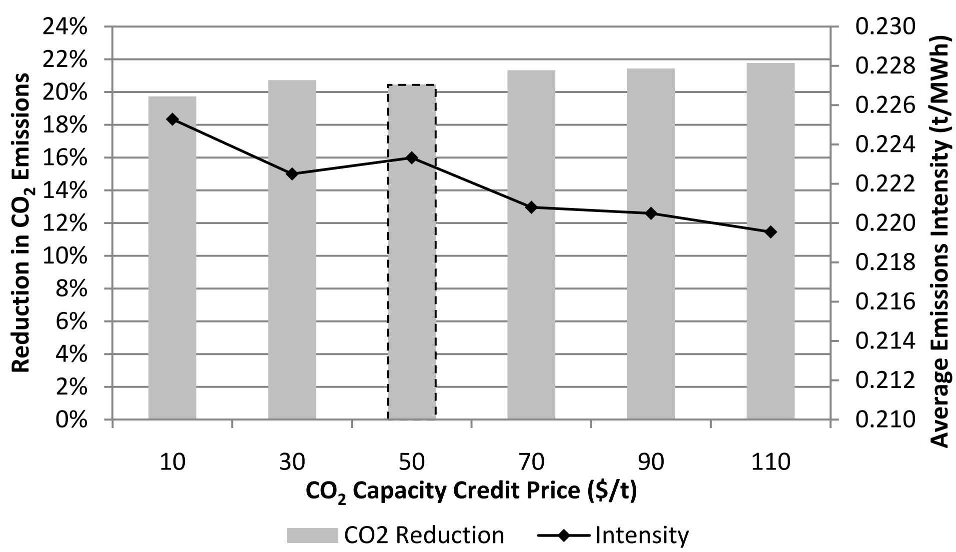

Figure 4.10: Scenario D: Reduction in CO_2 Emissions

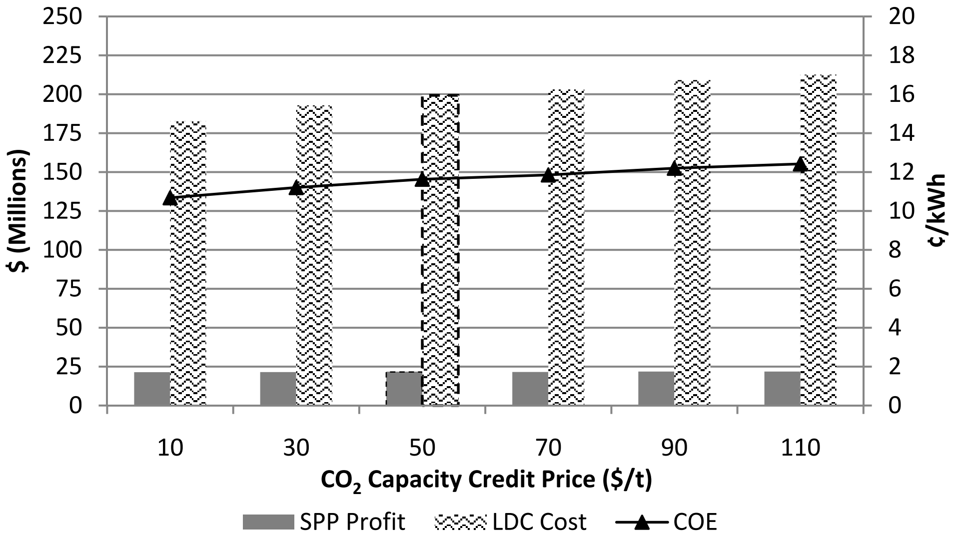

Figure 4.11: Scenario D: Costs and Revenues

The discount rate, R_k^{dg}, of 15% for SPPs is conservative, meaning that a significant rate of return is required before an SPP will invest in DG. This discount rate takes into account investment risks, including higher than anticipated operational costs, lower than predicted capacity factors, and the use of unproven technology. Due to their high capital costs, solar-PV and wind turbine DG units are particularly sensitive to the rate of return, as they rely on future income many years ahead to break-even. Decreasing the discount rate will result in more solar-PV and wind turbine DG investments while crowding out CHP DG investment; conversely, increasing the discount rate will slow solar-PV and wind turbine DG investments and increase CHP DG investments.

The capital cost of solar-PV and wind turbine DG, $Cc^{dg.v}$, is large, and thus their changes will impact the timing of investments. Reducing their costs will bring earlier investment (crowding out CHP DG), while increasing the capital cost will delay investment (allowing for more CHP DG investment).

The price paid for energy to SPPs through the SOP is fixed and is not be a source of uncertainty to the SPP. However, these rates may vary across jurisdictions; variations will significantly influence investment. Higher SOP rates will lead to earlier (and larger) investments. Wind and solar-PVs are particularly sensitive to changes in the SOP since they are relied upon to recover their high capital costs; lower SOP rates will dramatically reduce investments in these technologies. Similarly, changes to the capacity factors of wind and solar-PV will alter their investment; lower ECFs will result in less output per MW capacity, decreasing returns resulting in smaller and later investments (higher ECFs will have the opposite effect).

The high cost of fuel for diesel engines precludes investment in this technology for all but backup generation (which is not modelled here). The cost of natural gas is offset by SOP premiums thus permitting a reasonable rate of return. A drop in the price of fuel will make CHP investment more enticing to SPPs, in which case it will become preferred over investments in other DG technology.

The results of Scenarios C and D, in particular LDC and consumer costs, are likely sensitive to the base level of carbon emissions; this is discussed below.

4.4.6 Analysis and Discussion

In this subsection, the programs and results will be discussed in light of possible regulatory objectives: emissions reduction and increased investment in DG.

At the incentive rates discussed in Section 4.1.1, Ontario's SOP is effective in increasing investment in CHP and wind technologies (Case-2), which would not otherwise occur without incentives (Case-1). Except for the solar-PV investments that are not predicted by the simulations, this corresponds to what is actually occurring in Ontario. The discrepancy in solar-PV investments may be due to self-subsidies from investors, *e.g.*, by way of lower discount rates, that are not included in the model.

If a reduction in carbon emissions from electricity production is the goal of the SOP (Case-2), it essentially will cost the consumer an additional 3.6¢/kWh for a mere 1.5 percentage point additional reduction; this translates to a whopping cost of emissions reduction of \$1890/t. It would be far more effective to allow LDCs (only) to purchase and operate their own DG, *saving* consumers 0.17¢/kWh compared to a *SPP-inclusive environment* (Case-1) and reducing emissions by a further 5 percentage points. These results may change in favour of SOPs if associated benefits from CHPs are accounted for. It may be better to design FIT programs to target only specific technologies, such as CHP. In troubled economic times, it seems difficult to justify subsidizing solar-PV given the significant financial burden it will impose. Wind technology, on the other hand, is almost at a point that subsidies will no longer be required as costs drop due to advances in the technology or economies of scale.

The implementation of carbon taxes in combination with an existing SOP (Case-2T) results in a large reduction in emissions, but at the cost of CHP investment. Furthermore, with a carbon tax of \$50/t, as in Case-2T, the cost of reducing emissions is equal to \$763/t, which is significantly lower than the Case-2 cost of \$1890/t. If the carbon tax is further increased the incremental benefit is small and will result in disproportionally increased costs to consumers. If the objective of policy makers is to reduce carbon emission on a global scale, these carbon taxes must be carefully designed lest they cut CHP investment.

Imposing a carbon cap-and-trade mechanism in addition to offering the SOP (Case-2CT) has the same effect on investment as the tax-only scheme (Case-2T). The only notable difference is a slight increase in CO_2 emissions, afforded to the CHP producer by the cap, and thus reducing its per unit costs. Despite higher returns to wind and solar-PV SPP's through trading of emissions credits, the application of the cap-and-trade mechanism does not significantly alter DG investment because the distribution system is already saturated with DG. It should be noted that this work does not consider differentiated cap-and-trade schemes applied to one generation entity and not the other. However, if such discriminatory cap-and-trade schemes are applied then emissions may increase.

The analysis conducted in Scenario D shows that, at the distribution system level, carbon credit prices have little effect on investments, emissions, and LDC/consumer cost in a SOP environment. Investments in renewable energy DG change little, and a measurable drop in clean energy DG (CHP) is only experienced with higher carbon credit prices. The cost to consumers is small at 0.17¢/kWh per \$10/t increase. It can be concluded that volatile credit price markets (within the ranges explored) bear little risk to governments in terms of meeting carbon reduction goals and little impact to consumers in terms of program costs. Investment in renewable energy DG also bears little risk to the SPP (investments are profitable regardless of prices); however, higher credit prices may hurt returns on CHP investment, and thus risk-adverse SPPs may choose not to invest in this technology.

Results from the model are sensitive to carbon emission rates from bulk generation and, thus, the results discussed here are particular to Ontario (and Canada, which has similar rates). Ontario generates relatively clean energy – with most power originating from hydro and nuclear generation [90]. If a cap-and-trade mechanism were to be implemented in Ontario, it is expected that electricity generation would not be a significant driver of high carbon credit prices regardless of capacity allocations. The effect of other drivers, such as economic growth and emissions from other industries is not known, however, and thus the analysis on a range of carbon credit prices, as above, is necessary.

In jurisdictions where significant electricity supply is through fossil-fuel or coal based generation, such as in some U.S. states, the impact of carbon tax and cap-and-trade mechanisms are expected to be different. The implementation of a carbon tax or the allocation of capacity credits in a cap-and-trade mechanism at levels similar to those discussed in this research are expected to have a larger impact on LDC and consumer costs than if implemented in Ontario. Mitigating instruments may include relaxing the allocation of capacity credits or setting an upper limit on carbon credit prices; however, for brevity the effects of these options have not been analyzed.

The most effective policy in reducing emissions and increasing DG investment is to allow LDCs to build and operate DG to support their distribution system (Case-3). By investing in DG, LDCs are able to optimally integrate and utilize them to offset expenses otherwise incurred by importing energy. It allows them to determine the mix of external grid/market purchased energy versus generation from DG units. Implementing a tax-only mechanism in this case may have a negative effect on emissions and hence, in this regulated environment FITs are not required. Creating partnerships between the LDC and industry may increase CHP investment and reduce global emissions. Although integrating the LDC and DG investments is the cheapest route to achieving emissions and investment goals, it may not be feasible in all jurisdictions, such as in Ontario, where such a practice may be considered as unfair competition to SPPs. This conclusion assumes that the LDC is a public utility, acting in the best interest of its taxpayers and consumers.

4.5 Concluding Remarks

This chapter presents a distribution system planning model that is suitable for examining the impact of regulatory policies on DG unit investments by SPPs or LDCs. By examining these investment decisions, it is possible to determine the effects of the policies on long-run energy dispatch and purchases and thus predict the role the policies play on distribution system economics and environmental emissions.

This research examines three major policy cases representing a *SPP-inclusive environment*, a *SPP-friendly environment* incorporating FITs, and a tightly regulated system with only the LDC participating. These cases are applied to a 32-bus radial distribution system using market and incentive rates currently in place within Ontario, Canada, implemented under the SOP.

Without additional incentives, it is found that wind DG units are close to being viable. FITs, such as Ontario's SOP, are necessary to increase investments in CHP and solar-PV units (especially in the near term). However, the SOP is found to be overly costly if its sole purpose is to reduce emissions. Adding either a tax or cap-and-trade mechanism to the SOP reduces both emissions and energy cost. The most effective policy case, from the environmental emissions viewpoint, is the tightly regulated system, with the lowest emission and lowest cost, and with no FIT necessary.

By successfully encouraging SPPs to invest in DG units, via the policies discussed in this chapter, a large number of proposals may await LDCs. As the host utility providing network access to these DG units, LDCs are responsible for approving connections to their system; however, without systematic coordination a large number of proposals will lead to technical and economic inefficiencies. The issue of how best to modify and accept investment proposals so that maximum DG penetration is reached, and the goals of the regulators are achieved, is addressed in the following chapter.

Chapter 5

Coordination of Small Power Producer DG Capacity Investments[1]

5.1 Introduction

In the planning model of Chapter 3, the LDC exhibits full control over where it may place its own DG units and limited control over the placement of SPP-DG units. In the latter case, placement options for SPP-DG units are pre-determined, with little negotiation between investing SPPs and between the LDC and investing SPPs. As is in practice, SPP investment proposals are evaluated by the LDC on a case-by-case basis; proposals are accepted or rejected based on whether it is technically feasible to integrate them into the distribution system. Multiple DG unit proposals are not considered concurrently, and feedback mechanisms between the LDC and SPPs is minimal. Proposals are not coordinated in a systematic manner so that approvals are matched with system requirements.

Such arbitrary placement is not optimal from a technical and economic standpoint, but yet there is no literature reported that develops a coordinated plan for the approval and absorption of SPP DG proposals taking into consideration the technical constraints of the LDC's existing infrastructure and its ability to provide grid connection to the DG units while keeping its distribution network within operating limits. Connection charges, or tariffs in the form of paybacks or AACRs as discussed in Chapter 2, can be used by LDCs as incentives to localize DG where it most benefits the distribution system. One drawback, however, is that such a system provides no hard caps; SPPs wishing to place DG units at 'costlier' locations may still do so, and can drive up the costs to the LDC and consumers by forcing

[1]The work presented in this chapter has been submitted for publication in S. Wong, K. Bhattacharya, and J.D. Fuller, "Coordination of Investor-Owned DG Capacity Growth in Distribution Systems," *IEEE Trans. on Power Syst.*, Submitted.

system upgrades. Furthermore, such a system requires the LDC to have authority to offer location-based tariffs, which is not always the case. As in Ontario, tariffs are the responsibility of a regulatory agency and LDCs are only permitted to charge connection costs.

With more incentive programs being introduced by governments, there will be an increasing influx of SPPs making DG investments. As has been noted in Chapter 4, the implementation of FITs aimed at encouraging private investment by SPPs in clean and renewable DG technologies has arguably been a large success in Ontario, resulting in 428 contracts with a total of 1.4 GW generating capacity, as of February 2009 [94]. Further compounding DG implementation issues is that, in jurisdictions such as Ontario, LDCs are not permitted to place their own DG units (except for security and stability reasons) but must accommodate all DG proposals as is technically feasible.

From the perspectives of regulatory agencies and LDCs, the uncoordinated approach means that SPP-DG investment may not be realized to their full potential, resulting in a loss of clean/renewable generation sources. From the perspective of SPPs, this simple process may result in under-utilized capital and lost opportunities.

5.1.1 Overview of the Coordination Process

This chapter introduces a new method for coordinating the approval process of DG proposals submitted by SPPs to the LDC. For practicality, this method considers that interactions between SPPs and the LDC are for information exchange only – the SPPs submit their proposals and the LDC advises them of their technical feasibility. Furthermore, the actions and decisions by the LDC are considered to be fair, neutral, and transparent. The basic functioning of the proposed method is as follows:

- SPPs submit their respective proposals to the LDC. They would ideally specify the location, size, year of commissioning, and production of their proposed investments. Note that, in real-world implementation, SPPs will follow their own procedures to devise investment proposals. Here, in order to illustrate the proposed method, a plausible model is used which assumes, realistically, that SPPs operating in deregulated markets seek to maximize their profits *(SPP investment module, Fig. 5.1)*.
- The LDC is responsible for ensuring the distribution system's operational feasibility and that constraints are met. It considers the distribution system demand/supply balance, voltage limits, feeder capacities, and other technical constraints in its coordination program to verify feasibility of the SPP proposals *(LDC's DG Coordination Algorithm, Fig. 5.1)*. The LDC determines the production cuts required to meet system voltage and feeder limits using a combination of load flow calculations and the concept of *domains and*

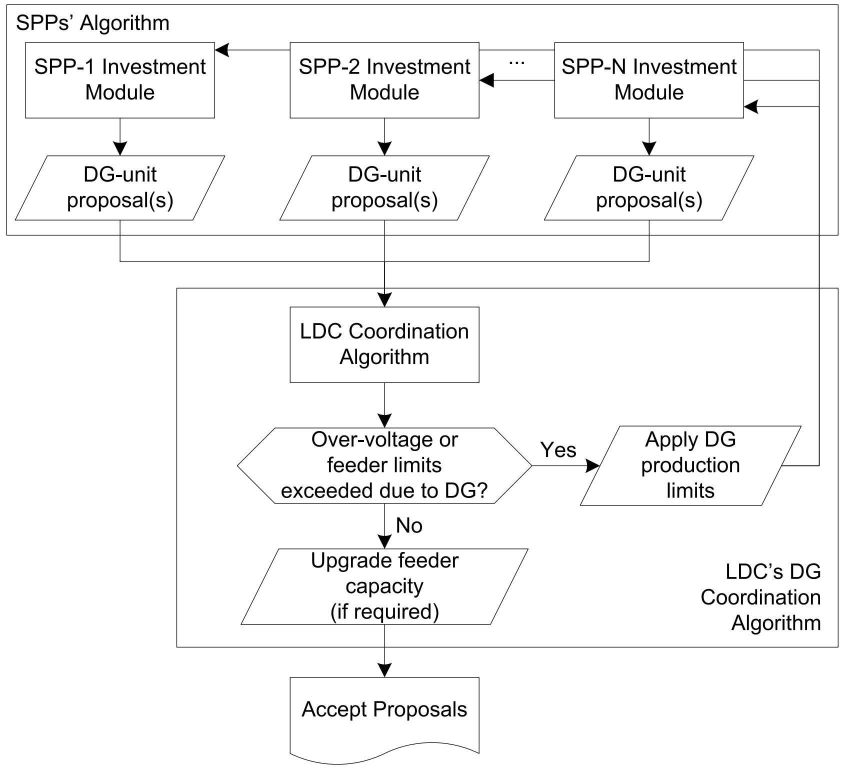

Figure 5.1: Overview of SPP and LDC Algorithms

commons [99]. These cuts are assigned to those DG units which are most responsible for the infeasibilities.

- These production cuts are then passed to the SPPs, at which point they revise their proposals accordingly. They may a) accept the production cuts, b) revise production and or/location of DG unit(s), or c) drop DG unit proposal(s) altogether.
- This process is then repeated until no further revisions are required from the SPPs. If there are feeder overloads, but they cannot be mitigated through production cuts, then the LDC is responsible for making the necessary feeder upgrades.

The proposed methodology uses a number of assumptions pertaining to the SPPs and the LDC:

- SPPs operate independently from each other and one is not significantly larger than the other– if SPPs operate independently from one another, and they are relatively equal in size, then the potential for collusion amongst SPPs by crowding out others is minimized. Rules on FIT program participation can be appropriately designed to address this issue.
- SPPs do not share system buses with one another, *i.e.* there is only one DG unit proposal per bus.
- The system load flow is feasible, neglecting feeder capacities, up to the plan-

ning horizon, without additional SPP investment. In essence, the LDC has plans to meet its future demand without relying on the participation of SPPs.
- Imports and exports from substation(s) and intertie(s) are cost optimized (amongst themselves) to meet remaining system demand not met by DG proposals; however, they will not redistribute energy flows (amongst themselves) to avoid feeder overload due to the DG proposals.
- SPP DG unit proposals with production less than demand at the sited bus cannot be constrained by the LDC; they are directly approved.
- Feeder upgrades, when deemed necessary, are the responsibility of the LDC.
- Only active power flows are considered when maintaining feeder limits.

5.2 Description of the Proposed DG Coordination Scheme

The proposed coordination framework comprises one SPP module pertaining to SPP specific DG unit investments (described in Section 5.3.1) and four modules pertaining to the LDC's DG Coordination Algorithm (DGCA, discussed in Sections 5.3.2 to 5.3.5). The four modules forming the basis of the DGCA are the Power Flow, Domains and Commons, DG Output Reduction, and Feeder Build modules. The DGCA, showing the relationships between each module, is presented in Fig. 5.2.

5.2.1 SPP Investment Module

The SPP Investment Module mimics SPPs' decisions by choosing projects that maximize their individual profits, which are modelled to be independent of one another. This module outputs the DG unit proposal(s) for each SPP, which includes the unit's proposed site, size, commissioning date, and production schedule over the planning period. However, only DG unit site(s) and schedule(s) are forwarded to the LDC for co-ordination. It takes as constraints DG unit production limits set by the LDC's DGCA.

5.2.2 LDC Coordination Modules

The proposals, after being submitted to the LDC by SPPs, must first be collated before they can be read by the LDC modules: for every combination of i and k, a generator index, g, is assigned and the SPP decision variable $p^{dg}_{k,i,b,t}$ is transformed into parameter $P^{dg}_{g,b,t}$. Once collated, the proposals are forwarded to the Power Flow Module and β, which counts the number of updates to the DG unit production limits in the current round, is reset to zero. If DG production limits are set, either by the Power Flow Module or the DG Output Reduction Module, β is incremented by

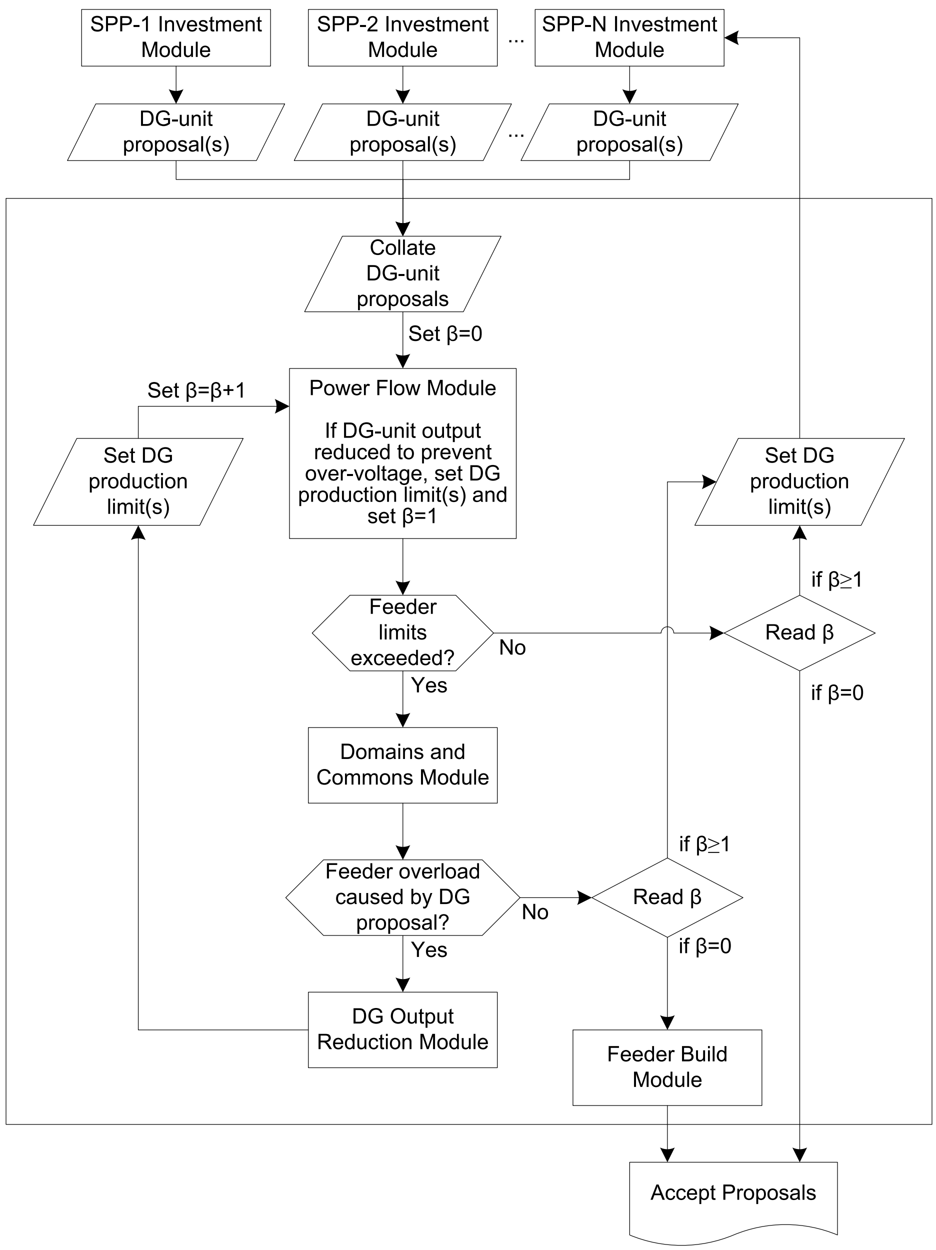

Figure 5.2: Details of DG Coordination Algorithm

one. A value of $\beta \geq 1$ indicates that the SPPs must consider additional constraints and submit revised proposals.

The Power Flow Module solves for the optimal power flow of the distribution system, using full load flow equations, and determines feeder power flows. DG unit production, $P^{dg}_{g,b,t}$, is treated as a parameter subject to reductions, $P.rdn^{dg}_{g,b,t}$, required to meet the limits, $P^{dg.max}_{k,i,b,t}$, set by the DG Output Reduction Model. DG production limits may also be set within the Power Flow Module itself, as required, to prevent bus over-voltages. Once the optimal power flow has been solved, feeder capacities are subtracted from feeder power flows determine feeder overloads, $P.ovld^{fdr}$, if any. If an overload exists then the distribution system power flow data is forwarded to the Domains and Commons Module.

The Domains and Commons Module is used to determine the contributions of SPP DG unit proposals to feeder overloads. If SPP DG unit proposals are indeed responsible, then a dataset listing feeder overloads and their DG unit contributions are forwarded to the DG Output Reduction Module. Conversely, if overloads cannot be attributed to specific SPP DG unit proposals but there are updated production limits, indicated by $\beta \geq 1$, then the whole algorithm is repeated, starting with the SPP Investment Modules. If there are no updated production limits, *i.e.* $\beta = 0$, the Feeder Build Module is run to determine the required feeder upgrades, $w^{fdr}_{(i,j),t}$.

The DG Output Reduction Module is responsible for finding the DG unit production cuts, $p.rdn^{dg}_{g,b,t}$, necessary to reduce feeder overload. This variable, $p.rdn^{dg}_{g,b,t}$, is subtracted from the DG unit production parameter, $P^{dg}_{g,b,t}$, to arrive at the DG unit production limits, $P^{dg.max}_{k,i,b,t}$, that are passed to the LDC's Power Flow Module and the SPP Investment Module.

If no feeder overloads exist, then the current LDC coordination round is concluded: if $\beta = 0$, the process is complete and proposals accepted; if $\beta \geq 1$, revisions to DG unit proposals, using the updated production limits, are required from the SPPs.

5.3 Mathematical Description of Modules

5.3.1 SPP Investment Module

Objective Function

The objective function is maximizing discounted sum of the SPP's profits, J_A, in Eq. (5.1). It is assumed that a SPP only specializes in one technology and therefore, if it proposes multiple DG units, they will be of the same technology.

$$J_A = \max \sum_{k \in K, i \in N, t \in T} \frac{1}{(1+R_k^{SPP})^t} \Bigg(\sum_{b \in B} P_{k,i,b,t}^{dg} Hrs_b \Big(Ce_{k,b,t}^{dg} + Ce_{k,b,t}^{dg.FIT} - Co_{k,t}^{dg} \Big) \quad \text{(a)}$$

$$- (w_{k,i,t}^{dg} Cc_{k,t}^{dg.v} + z_{k,i,t}^{dg} Cc_{k,t}^{dg.f})(1+R_k^{SPP})(1-\alpha_{k,t}) \Bigg) \quad \text{(b)} \tag{5.1}$$

where the salvage value, α, is found by a depreciation formula; here, straight-line depreciation is used:

$$\alpha_{k,t}^{dg} = \frac{1}{Ls_k^{dg}} (t + Ls_k^{dg} - H - 1) \frac{1}{(1+R_k^{SPP})^{(H-t+1)}}$$

$$\forall\, k, t : t + Ls_k^{dg} \geq H \tag{5.2}$$

$$else : \alpha_{k,t}^{dg} = 0 \tag{5.3}$$

Line (a) in (5.1) represents the SPPs' income from the sale of energy (composed of the market price of energy and applicable FITs) net of operation and maintenance costs. Line (b) is the capital cost from building the DG units, which includes both per unit ($/MW) and EPC fixed ($) costs. The $(1 + R_k^{SPP})$ factor accrues capital costs to the beginning of each year (whereas energy income is accrued at year-end). To mitigate the end-effects from this module's finite planning horizon, the savage value of the units at the horizon, Eqs. (5.2) and (5.3), are subtracted from the capital costs.

DG Build

Constraint (5.4) ensures that total investment in a certain technology at the same site is limited while (5.5) ensures that the EPC costs are included in the objective function by the appropriate selection of the binary variable $z_{k,i,t}^{dg}$.

$$\sum_{t=1}^{T} w_{k,i,t}^{dg} \leq W_k^{dg.max} \qquad \forall k \in K, i \in N \tag{5.4}$$

$$w_{k,i,t}^{dg} \leq z_{k,i,t}^{dg} M \qquad \forall k \in K, i \in N, t \in T \tag{5.5}$$

DG Energy Limits

Power from DG units is limited by unit size, given in (5.6).

$$P_{k,i,b,t}^{dg} \leq \sum_{t'=1}^{t} w_{k,i,t'}^{dg} \qquad \forall k \in K, i \in N, b \in B, t \in T \tag{5.6}$$

Fuel availability will impact energy production by a DG unit. For example, wind speed and solar radiation levels vary considerably by location throughout the day, thus impacting the production from wind and solar-PV DG. An expected capacity factor averaged out over peak, intermediate, and base load periods, for each bus, is used. For non-dispatchable units, such as wind and solar-PV DG, the ECF dictates the unit's production (based on size), as in (5.7). For dispatchable units, such as bio-gas and CHP, the ECF sets an upper limit on energy production, as in (5.8).

$$P^{dg}_{k,i,b,t} Hrs_b = ECF_{k,i,b} \sum_{t'=1}^{t} w^{dg}_{k,i,t} Hrs_b \qquad \forall k \in K^{nd}, i \in N, b \in B, t \in T \tag{5.7}$$

$$P^{dg}_{k,i,b,t} Hrs_b \leq ECF_{k,i,b} \sum_{t'=1}^{t} w^{dg}_{k,i,t} Hrs_b \qquad \forall k \in K, i \in N, b \in B, t \in T \tag{5.8}$$

The LDC may constrain, via the DGCA, the power produced by proposed SPP DG units in (5.9). If the DG unit affected is non-dispatchable, it may, in conjunction with (5.7), reduce the unit's maximum size. For dispatchable units, only energy production will be limited, although with all else unchanged there may be excess capacity. The full impact of this constraint is determined via J_A, as the SPP may choose a new site, cut production, or reduce proposed unit sizes.

$$P^{dg}_{k,i,b,t} \leq P^{dg.max}_{k,i,b,t} \qquad \forall k \in K, i \in N, b \in B, t \in T \tag{5.9}$$

SPP Capital Budget

Constraint (5.10) ensures that the present value of capital expenditures in DG units is less than the present worth of the allocated budget.

$$\sum_{t \in T, i \in N} \frac{1}{(1 + R^{SPP}_k)^{(t-1)}} \left(w^{dg}_{k,i,t} Cc^{dg.v}_{k,t} + z^{dg}_{k,i,t} Cc^{dg.f}_{k,t} \right) \leq Bgt^{SPP}_k \qquad \forall k \in K \tag{5.10}$$

Variable Limits

Variables $P^{dg}_{k,i,b,t}$ and $w^{dg}_{k,i,t}$ are positive; $z^{dg}_{k,i,t}$ is binary.

5.3.2 LDC Power Flow Module

The Power Flow Module is the first component of the LDC's DGCA, and solves for the optimal load flow of the distribution system. It takes, as a parameter, the SPPs' production schedule subject to DG unit production limits (set by the DG Output Reduction Module or by a previous run of the Power Flow Module).

Objective Function

The objective function is minimizing the LDC's discounted cost of energy, J_B, as given in (5.11).

$$
\begin{aligned}
J_B = \min \sum_{t \in T} \frac{1}{(1+R^{LDC})^t} \Big(\\
& \sum_{i \in N^{ss}, b \in B} P^{ss}_{i,b,t} Hrs_b Ce^{ss}_{b,t} \quad \text{c} \\
& + \sum_{i \in N^{int}, b \in B} P^{int}_{i,b,t} Hrs_b Ce^{int}_{b,t} \quad \text{d} \\
& + \sum_{i \in N, b \in B} Q^{cap}_{i,b,t} Hrs_b Ce^{cap} \quad \text{e} \\
& + \sum_{i \in N, b \in B} P.co^{dg}_{g,b,t} Hrs_b M^{dg.co}_{b,t} \Big) \quad \text{f}
\end{aligned}
\tag{5.11}
$$

Lines c and d, in (5.11), represent the cost of importing energy from the market, via substations, or neighbouring LDC's, via interties, respectively. If energy is exported from the distribution system, via these elements, then the income is credited to the LDC. Cost of reactive power supply, from capacitor banks, in represented by e. Since power purchased from the SPPs is a parameter for the LDC, this component is not included in the objective function.

In this module, it is possible for unchecked SPP DG unit production to cause bus over-voltages by violation of constraint (5.14). To prevent this, the load flow equation (5.12) permits the solver to constrain-off DG unit production, through the variable $P.co^{dg}_{g,b,t}$, and thus maintain a feasible solution. However, a high cost, $M^{dg.co}_{b,t}$, for constraining DG unit production off through $P.co^{dg}_{g,b,t}$, is required to ensure that DG units are constrained-off only to prevent voltage problems, in f.

Load Flow Equations

Power flows are modelled using full load flow equations, for each load demand block and year, as shown in (5.12) and (5.13). Active power imports/exports, in (5.12), can be met by a combination of substation and intertie exchanges or DG unit production (subject to DG unit coordination limits). The variable $P.rdn^{dg}_{g,b,t}$ is calculated as the difference between the DG unit production parameter $P^{dg}_{g,b,t}$ and limits $P^{dg.max}_{k,i,b,t}$ imposed in earlier iterations of the LDC modules. Reactive power is supplied via installed capacitor banks, in (5.13), since substation and intertie buses ideally operate at unity power factor and (in the absence of a reactive power market) DG units will only supply active power.

$$
\begin{aligned}
&-Pd_{i,b,t} + P^{ss}_{i,b,t} + P^{int}_{i,b,t} + \sum_{g \in G: \exists g \in i} \big(P^{dg}_{g,b,t} - P.rdn^{dg}_{g,b,t} - P.co^{dg}_{g,b,t}\big) \\
&\quad = \sum_{j \in N: \exists (i,j)} V_{i,b,t} V_{j,b,t} \big(Gg_{(i,j)} cos(\theta_{i,b,t} - \theta_{j,b,t}) + Bb_{(i,j)} sin(\theta_{i,b,t} - \theta_{j,b,t})\big) \\
&\qquad\qquad\qquad\qquad\qquad\qquad\qquad\qquad \forall i \in N, b \in B, t \in T
\end{aligned} \tag{5.12}
$$

$$
\begin{aligned}
&-Qd_{i,b,t} + Q^{cap}_{i,b,t} \\
&\quad = \sum_{j \in N: \exists (i,j)} V_{i,b,t} V_{j,b,t} \big(Gg_{(i,j)} sin(\theta_{i,b,t} - \theta_{j,b,t}) + Bb_{(i,j)} cos(\theta_{i,b,t} - \theta_{j,b,t})\big) \\
&\qquad\qquad\qquad\qquad\qquad\qquad\qquad\qquad \forall i \in N, b \in B, t \in T
\end{aligned} \tag{5.13}
$$

Voltage Limits

Proper voltage profiles are maintained through Eqs. (5.14) and (5.15).

$$V_{i,b,t} \leq V^{max} \qquad \forall i \in N, b \in B, t \in T \tag{5.14}$$
$$V_{i,b,t} \geq V^{min} \qquad \forall i \in N, b \in B, t \in T \tag{5.15}$$

Substation, Intertie, and Capacitor Limits

Substations and interties are modelled as bi-directional and can handle exchanges up to their capacity in either direction. Substation and intertie limits, Eqs. (5.16) to (5.19), can also be modelled as unidirectional by changing the right-hand-side of (5.17) and (5.19) to zero without loss of generality to this or other modules. Reactive power output of the capacitor banks are limited in (5.20).

$$P^{ss}_{i,b,t} \leq W^{ss}_{i,t} \qquad \forall i \in N^{ss}, b \in B, t \in T \tag{5.16}$$
$$P^{ss}_{i,b,t} \geq -W^{ss}_{i,t} \qquad \forall i \in N^{ss}, b \in B, t \in T \tag{5.17}$$
$$P^{int}_{i,b,t} \leq W^{int}_{i,t} \qquad \forall i \in N^{int}, b \in B, t \in T \tag{5.18}$$
$$P^{int}_{i,b,t} \geq -W^{int}_{i,t} \qquad \forall i \in N^{int}, b \in B, t \in T \tag{5.19}$$
$$Q^{cap}_{i,b,t} \leq W^{cap}_{i,t} \qquad \forall i \in N^{cap}, b \in B, t \in T \tag{5.20}$$

DG Constrained-off Limits

Equation (5.21) ensures that a DG unit is not constrained by more than its scheduled production (net of DG production limits applied downstream).

$$P.co_{g,b,t} \leq P^{dg}_{g,b,t} - P.rdn^{dg}_{g,b,t} \qquad \forall g \in G, b \in B, t \in T \tag{5.21}$$

Variable Limits

Variables $P^{ss}_{i,b,t}$, $P^{int}_{i,b,t}$, and $\theta_{i,b,t}$ are unrestricted; $Q^{cap}_{i,b,t}$, $V_{i,b,t}$, and $P.co_{g,b,t}$ are positive.

5.3.3 LDC Domains and Commons Module

This module draws upon the work of Kirschen *et al.* [99], whom use a system of commons and domains to estimate the contribution of individual generators to loads and feeder power flows. The algorithm used in this module remains unchanged from [99] except for modifications to treat substations and interties as either generators or loads depending on the power flow direction.

The input to this module is the solution from the Power Flow Module. The output of interest is the contribution, $Cntrb^{dg.fdr}_{g,(i,j),b,t}$, (as a fraction of total load) of each DG unit to feeder power flows, particularly those that are overloaded.

Due to the non-linear nature of power flows and the linear nature of the commons and domains algorithm, the contribution factors would not hold true for significant changes in system power flows. To mitigate these effects, the contribution factors are updated after every adjustment to DG unit production (per load block, per year) by the DG Output Reduction Module, as given in the Fig. 5.2.

5.3.4 LDC DG Output Reduction Module

The DG Output Reduction Module is entrusted with reducing feeder overload(s) by constraining the DG production of the single largest contributor to the overloads per load block and year, while also keeping the reduction in DG production to a minimum. The feeder overloads, $P.ovld^{fdr}$, using data from the Power Flow Module, are calculated by subtracting feeder capacities from feeder power flows. The module's primary inputs are the DG unit production schedules, feeder overloads and their limits, and the contribution of each DG unit to the overloads. The output from this module specifies the DG(s) whose production is to be constrained and its production limit, $P^{dg.max}_{k,i,b,t}$, which is calculated by subtracting $P.sub^{dg}_{g,b,t}$ from the DG unit production parameter, $P^{dg}_{g,b,t}$.

Objective Function

J_C, in (5.22), is a multi-criteria objective function. Its goal is to minimize remaining feeder overloads, $P.ovld^{fdr}$ by subtracting the least amount of DG unit production, $P.sub^{dg}$. Priority, however, is placed on reducing feeder overloads as set through the M^{rdn} parameter, where $P.sub^{dg} \ll M^{rdn}$.

$$J_C = \min \sum_{\substack{g \in G, \\ b \in B, t \in T}} P.sub^{dg}_{g,b,t} + \sum_{\substack{i,j \in N : \exists (i,j) \\ b \in B, t \in T}} M^{rdn} \; P.ovld^{fdr.r}_{(i,j),b,t} \tag{5.22}$$

Power Output Reduction Limit

Equation (5.23) ensures that a DG unit is not constrained by more than its scheduled production (net of DG production limits already applied).

$$P.sub^{dg}_{g,b,t} \leq P^{dg}_{g,b,t} - P.rdn^{dg}_{g,b,t} \qquad \forall g \in G, b \in B, t \in T \tag{5.23}$$

Unit Reduction Limit

To ensure that contribution factors from the Domains and Commons Module are always accurate, production from only one DG unit, per load block per year, can be reduced in each run of the module. This is enforced through Eqs. (5.24), (5.25), and (5.26).

$$\sum_{g \in G} z.rdn^{dg}_{g,b,t} \leq 1 \qquad \forall b \in B, t \in T \tag{5.24}$$

$$P.sub^{dg}_{g,b,t} \leq z.rdn^{dg}_{g,b,t} M \qquad \forall g \in G, b \in B, t \in T \tag{5.25}$$

$$P.sub^{dg}_{g,b,t} M \geq z.rdn^{dg}_{g,b,t} \qquad \forall g \in G, b \in B, t \in T \tag{5.26}$$

Feeder Overload Reduction Limits

The reduction to the power flow overload on a feeder is limited to the reduction in feeder power flow from reducing DG unit production, in (5.27). This limit is calculated by summing the reduction of each DG unit's production against the contribution of that unit to the feeder load. It should be reminded that cuts to a single DG unit's production may reduce power flows in multiple feeders.

$$P.rdn^{fdr}_{(i,j),b,t} \leq \sum_{g \in G} (P.sub^{dg}_{g,b,t} Cntrb^{dg.fdr}_{g,(i,j),b,t}) \qquad \forall i,j \in N, b \in B, t \in T \tag{5.27}$$

The second limit, in (5.28), requires the reduction in feeder overload plus remaining overload to be at least as large as the overload before reductions.

$$P.rdn^{fdr}_{(i,j),b,t} + P.ovld^{fdr.r}_{(i,j),b,t} \geq P.ovld^{fdr}_{(i,j),b,t} \qquad \forall i,j \in N, b \in B, t \in T \quad (5.28)$$

Variable Limits

Variables $P.sub^{dg}_{g,b,t}$, $P.ovld^{fdr.r}_{(i,j),b,t}$, and $P.rdn^{fdr}_{(i,j),b,t}$ are positive; $z.rdn^{dg}_{g,b,t}$ is binary.

5.3.5 LDC Feeder Build Module

The LDC may not be able to mitigate feeder overloads by reducing DG unit production, *e.g.*, if production is less than demand (as per the assumption in Section 5.1). Under this circumstance, the LDC has no choice but to increase feeder capacity as required. The DG coordination algorithm may call this Feeder Build Module, if necessary, as its last step.

Objective Function

The objective function, J_D in (5.29), is to minimize the increase in feeder capacity. Combined with (5.31), it minimizes the number of feeder upgrades. The symbol "$\exists(i,j)$" is shorthand for "a feeder exists from i to j".

$$J_D = \min \sum_{\substack{i,j \in N:\exists(i,j) \\ t \in T}} w^{fdr}_{(i,j),t} \quad (5.29)$$

Feeder Build

This constraint ensures that increases to feeder capacity are sufficient to meet feeder load, as given in (5.30) .

$$P.ovld^{fdr}_{i,j,b,t} \leq \sum_{t' \leq t} w^{fdr}_{(i,j),t'} + w^{fdr}_{(j,i),t'} \qquad \forall i,j \in N : \exists(i,j), b \in B, t \in T : P.ovld^{fdr}_{(i,j),b,t} > 0 \quad (5.30)$$

To minimize build costs to the LDC, only one upgrade per single feeder is permitted during the planning horizon, as per Eqs. (5.31) and (5.32).

$$\sum_{t \in T} z^{fdr}_{(i,j),t} + z^{fdr}_{(j,i),t} \leq 1 \qquad \forall i,j \in N : \exists(i,j) \quad (5.31)$$

$$w^{fdr}_{(i,j),t} \leq z^{fdr}_{(i,j),t} M \qquad \forall i,j \in N : \exists(i,j), t \in T \quad (5.32)$$

Table 5.1: 32-Bus System and LDC Parameters

Market price of energy, Ce_b^{ss}	Base: \$55/MWh
	Intm: \$72/MWh
	Peak: \$90/MWh
Horizon, H	5 years
Hours in year, Hrs_b	Base: 4380; Intm: 3504; Peak: 876
Year-0 demand, Pd (MW)	Base: 18.58; Intm: 31.58; Peak: 37.15
Growth in Pd	3% per year, uniform across all loads
LDC discount rate, R^{LDC}	8%
Voltage limits, V_{max}/V_{min}	1.03/0.98 p.u.
Capacitor capacity, W^{cap}	1 MVar (all buses)
Intertie capacity, W^{int}	5 MW
Substation capacity, W^{ss}	45 MW

Variable Limits

Variable $w_{(i,j),t}^{fdr}$ is positive and $z_{(i,j),t}^{fdr}$ is binary.

5.4 Case Study

A 32-bus radial distribution system, in Fig. 5.3, is used to validate the proposed DG coordination algorithm. It consists of a transmission grid-connected 45 MW substation at bus-1 and a 5 MW intertie at bus-30; both the substation and the intertie are bi-directional. Year-0 demand of the distribution system is 37 MW with a 3% annual growth in demand over the 5 year planning horizon. With the aid of 1 MVar capacitors installed at all buses, the distribution system load flow is feasible through the planning horizon without additional generator, substation, or intertie capacity. Additional LDC parameters are given in Table 5.1.

There are four SPPs willing to invest in the LDC system; their parameters are given in Table 5.2. Each SPP is exclusive to one technology and the budget of each allows for significant investment in corresponding generating units of that technology. All SPPs have different discount rates. The low discount rate of SPP_4, necessary to induce investments in solar-PV because of its high capital cost, reflects a self-subsidy by the investor. The ECF adjustment, ECF^{adj}, for each SPP reflects availability of the bus to each SPP (zero if it is not available) combined with geographical factors affecting DG unit production. Actual ECF is calculated by multiplying the adjustment by the maximum ECF, in Table 5.3, of the corresponding DG technology.

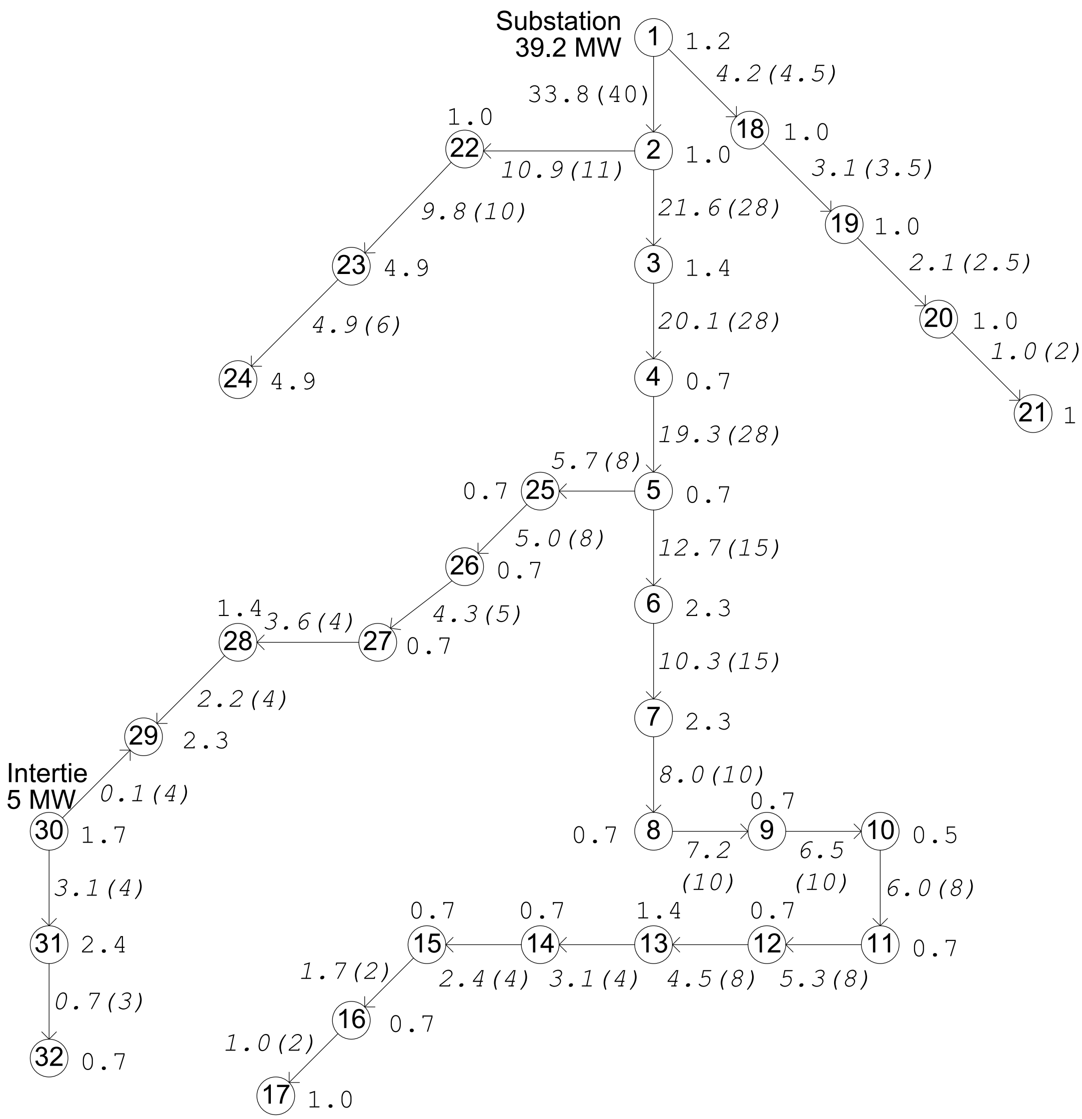

Figure 5.3: 32-Bus Radial Distribution System: No SPP Participation. The circled numbers denote bus numbers. Year-5 peak power flows and year-0 feeder sizes (in brackets) are denoted beside each feeder, in MW.

Table 5.2: SPP Parameters

	SPP_1	SPP_2	SPP_3	SPP_4
Technology	Bio-Gas	Nat. Gas CHP	Wind Turbine	Solar-PV
Budget, Bgt^{SPP}	\$10M	\$2M	\$40M	\$80M
Horizon, H	– 5 years –			
Discount rate, R^{SPP}	8%	12%	10%	3%
$ECF^{adj}_{bus\text{-}3}$	0	0	0.94	0
$ECF^{adj}_{bus\text{-}4}$	0	0	0	1.00
$ECF^{adj}_{bus\text{-}5}$	0	0	0	1.00
$ECF^{adj}_{bus\text{-}14}$	0	0	0.92	0
$ECF^{adj}_{bus\text{-}15}$	0	0	0.94	0
$ECF^{adj}_{bus\text{-}16}$	0	0	0.95	0
$ECF^{adj}_{bus\text{-}23}$	1.00	0	0	0
$ECF^{adj}_{bus\text{-}24}$	1.00	0	0	0
$ECF^{adj}_{bus\text{-}27}$	0	0.96	0	0
$ECF^{adj}_{bus\text{-}28}$	0	0.98	0	0
$ECF^{adj}_{bus\text{-}29}$	0	1.00	0	0
$ECF^{adj}_{bus\text{-}31}$	0	0	0.98	0
$ECF^{adj}_{bus\text{-}32}$	0	0	1.00	0

Table 5.3: DG Unit Parameters [9], [10], [11], [12], [92]

Technology	Bio-Gas	Natural Gas CHP	Wind Turbine	Solar-PV
EPC cost, $Cc^{epc.dg}$	\$100k	\$50k	\$100k	\$100k
Capital cost, $Cc^{v.dg}$	\$4,000k	\$400k	\$2,000k	\$7,500k
Decrease in $Cc^{v.dg}$	1%/year	-	1%/year	4%/year
Energy price, Ce^{dg}_{Base}	\$55/MWh	→	→	\$55/MWh
Ce^{dg}_{Intm}	\$72/MWh	→	→	\$72/MWh
Ce^{dg}_{Peak}	\$90/MWh	→	→	\$90/MWh
FIT, $Ce^{dg.FIT}_{Base}$	\$55.4/MWh	\$40/MWh	\$55.4/MWh	\$365/MWh
$Ce^{dg.FIT}_{Intm}$	\$38.4/MWh	\$40/MWh	\$38.4/MWh	\$348/MWh
$Ce^{dg.FIT}_{Peak}$	\$20.4/MWh	\$80/MWh	\$20.4/MWh	\$330/MWh
Operating cost, Co^{dg}	0	\$75/MWh	\$10/MWh	\$4/MWh
ECF^{max}_{Base}	0.92	0.92	0.40	0.05
ECF^{max}_{Intm}	0.92	0.92	0.30	0.20
ECF^{max}_{Peak}	0.92	0.92	0.20	0.25
Lifespan, Ls	20 years	20 years	25 years	30 years
Max size, $W^{max.dg}$	10 MW	10 MW	10 MW	10 MW

DG parameters, arranged by technology, are given in Table 5.3. These parameters are used only by the SPP to aid in their investment decisions and production scheduling. Two prices for energy are given: Ce^{dg}, the market price for energy, and Ce^{FIT}, the incentive payment to SPPs from the feed-in-tariff. The net operational and fuel cost for bio-gas is zero, since costs are assumed to be offset by gate fees for fuel and income from selling the by-products as fertilizer. The ECF given for each technology is its maximum technical limit; locational factors, as given in Table 5.2, may reduce these further. It has been assumed that DG unit sizes must be 10 MW or under.

5.4.1 Computational Details

The proposed DG coordination algorithm was programmed and executed in the GAMS environment [89] on an IBM eServer xSeries 460 with 8 Intel Xeon 2.8 Ghz processors and 3 GB (effective) of RAM. Table 5.4 gives the solver used for each module and model statistics for a single run of each module.

The SPP Investment Module and DG Output Reduction Modules are MILP and the Power Flow Module is a NLP. The Commons and Domains Module, not

Table 5.4: Model Statistics - Initial Run

	SPP Inv. Module	Power Flow Module	DG Output Rdn. Module
Solver	CPLEX	MINOS	CPLEX
Type	MILP	NLP	MILP
Blocks of Equations	8	13	7
Blocks of Variables	4	7	5
Single Equations	5,573	2,581	366
Single Variables	3,201	1,561	261
Non-Zero Elements	17,906	N/A	890
Discrete Variables	640	N/A	90
Generation Time (s)	0.125	0.094	0.016
Resource Usage (s)	0.140	6.844	0.046
Relative Gap (%)	0.0017	N/A	0.

shown in the table, uses mainly parameter arithmetic and thus model statistics are not available; the run-time of a single run of this module is a few seconds. The total run-time for this framework is a few minutes, about half of which is spent on the compilation and reading of data. Computational burden is not an issue in implementing this framework.

5.5 Results and Discussion

5.5.1 Process

The proposed DGCA was executed and it was seen that three submissions by the SPPs were required before an optimal solution was reached. The process required for this test system, corresponding to the flow chart in Fig 5.2, is as follows:

```
Round 1 - Initial Proposal
  SPPs' Investment Module
  LDC DG Coordination Algorithm (2 runs)
    Power Flow Module
    Domains and Commons Module
    DG Output Reduction Module
  Power Flow Module
Round 2 - Revision 1
  SPPs' Investment Module
  LDC DG Coordination Algorithm (3 runs)
    Power Flow Module
```

```
    Domains and Commons Module
    DG Output Reduction Module
  Power Flow Module
Round 3 - Revision 2
  SPPs' Investment Module
  Power Flow Module
<Procedure Complete>
```

In the first round, two iterations of the LDC's DGCA are required before a set of production constraints are returned to the SPPs for proposal revision. The iterations are required to ensure that the decisions by the DG Output Module use accurate data from the Power Flow Modules and subsequent Domains and Commons Module. After the SPPs submit their revised proposals (first revision) three iterations are required by the LDC's DGCA before an additional set of production constraints (reflecting the changes from their initial proposal) can be sent back to them. The SPPs' third proposal (second revision) is checked via the LDC's Power Flow Module and is found to be acceptable as-is. No feeder upgrades are necessary.

5.5.2 SPP-DG Participation

The initial, first revision, and second revision DG build proposals are given in Table 5.5. The DG production limits appended after each round, determined by the LDC via the DGCA, are given in Table 5.6. Where there is no limit given, no limit is imposed. These limits are passed to the SPPs at the end of each round. In Table 5.5, it is noted that SPP_1's 2.5 MW DG unit is moved from bus-23 to 24, even though no production limits are imposed (in Table 5.6); this relocation occurs because the present worth at either bus is the same and thus the choice between the two is arbitrary.

SPP_2's CHP DG unit is shifted from bus-29, to bus-28, and finally to bus-27 as the SPP maximizes its production in light the production limits imposed by the LDC in Table 5.6. Although both bus-28 and bus-29 have higher ECFs than bus-27, it is obvious that, given the limits, bus-27 can produce more and is financially the best site. SPP_3 initially proposes two units of 10 MW each at bus-31 and bus-32 because these buses have the highest ECF. However, both of these sites had at least one production limit of zero (Table 5.6), and since wind-turbines are not dispatchable both sites must be rejected. The SPP's second choice, bus-15 and bus-16, are again constrained: bus-15 cannot have any production and bus-16 is partially constrained. Since bus-16 has a higher ECF than the remaining options, a DG unit of 6.7 MW is approved. SPP_3's remaining capital is spent on DG units at the bus-2 remaining buses, bus-3 and bus-14.

The DG unit proposals by SPP_4 were not the source of any feeder overloads and thus were not subject to any production limits, thus the proposals remained unchanged throughout the process and were approved as-is. The proposed year of

Table 5.5: SPP-DG Unit Proposals

Proposal	Initial		Revision 1		Rev. 2 (Final)	
	Size (MW)	Yr	Size (MW)	Yr	Size (MW)	Yr
SPP_1 (Bus-23)	-	-	2.5	1	2.5	1
SPP_1 (Bus-24)	2.5	1	-	-	-	-
SPP_2 (Bus-27)	-	-	-	-	4.9	1
SPP_2 (Bus-28)	-	-	4.9	1	-	-
SPP_2 (Bus-29)	4.9	1	-	-	-	-
SPP_3 (Bus-3)	-	-	-	-	10.0	1
SPP_3 (Bus-14)	-	-	-	-	3.3	1
SPP_3 (Bus-15)	-	-	10.0	1	-	-
SPP_3 (Bus-16)	-	-	10.0	1	6.7	1
SPP_3 (Bus-31)	10.0	1	-	-	-	-
SPP_3 (Bus-32)	10.0	1	-	-	-	-
SPP_4 (Bus-4)	10.0	3	10.0	3	10.0	3
SPP_4 (Bus-5)	2.8	3	2.8	3	2.8	3

commissioning for its DG units, in year-3, are due to the declining costs of solar-PV technology (at years-1 and 2 investment is not profitable).

The placement of SPP-DG to year-5 and their corresponding sizes within the 32-bus radial distribution system, according to their initial proposals and unconstrained by the DGCA, are shown in Fig. 5.4. Peak load power flows are also shown next to each line segment and in bold if overloaded. Fig. 5.5 depicts SPP-DG when placed according to the final proposals, as determined by the DGCA. It is clearly seen in these figures that the DGCA is siting DG units away from feeders (27,28), (28,29), and (29,30) that are overloaded and into feeder branches that have extra capacity.

The LDC's import schedule and each SPPs' production/contract schedules for each load demand block in years 1 to 5, once proposals have been finalized and approved, are given in Table 5.7. All of the SPP's DG units are scheduled to produce at full capacity once built, maximizing their respective incomes. Note that the coordination algorithm is not impeding the SPP's ability to make a profit. Imports via the substation and intertie are used to meet the remaining load demand. Intertie imports are maximized at 5 MW for intermediate and peak load demand blocks to minimize losses and thus costs to the LDC, which is possible because it lies towards the end of a feeder branch. The lower imports from substations and interties during the base period reflects lower demand and unchanged DG unit injections.

Table 5.6: DG Unit Production Limits

Added	SPP	Bus	Load Block	Yr	Limit (MW)
Round 1	SPP-2	29	Base	5	4.4
			Intm	1,2	0.0
			Intm	3	0.6
			Intm	4	0.1
			Intm	5	0
			Peak	1-4	0
			Peak	5	0.2
	SPP-3	31	Intm	1-5	0.0
			Peak	1-4	0.0
			Peak	5	0.9
	SPP-3	32	Base	1-5	0.0
Round 2	SPP-2	28	Base	1-5	0.0
	SPP-3	15	Base	1-5	0.0
		16	Base	1	2.6
			Base	2	2.7
			Base	3	2.8
			Base	4	2.8
			Base	5	2.9

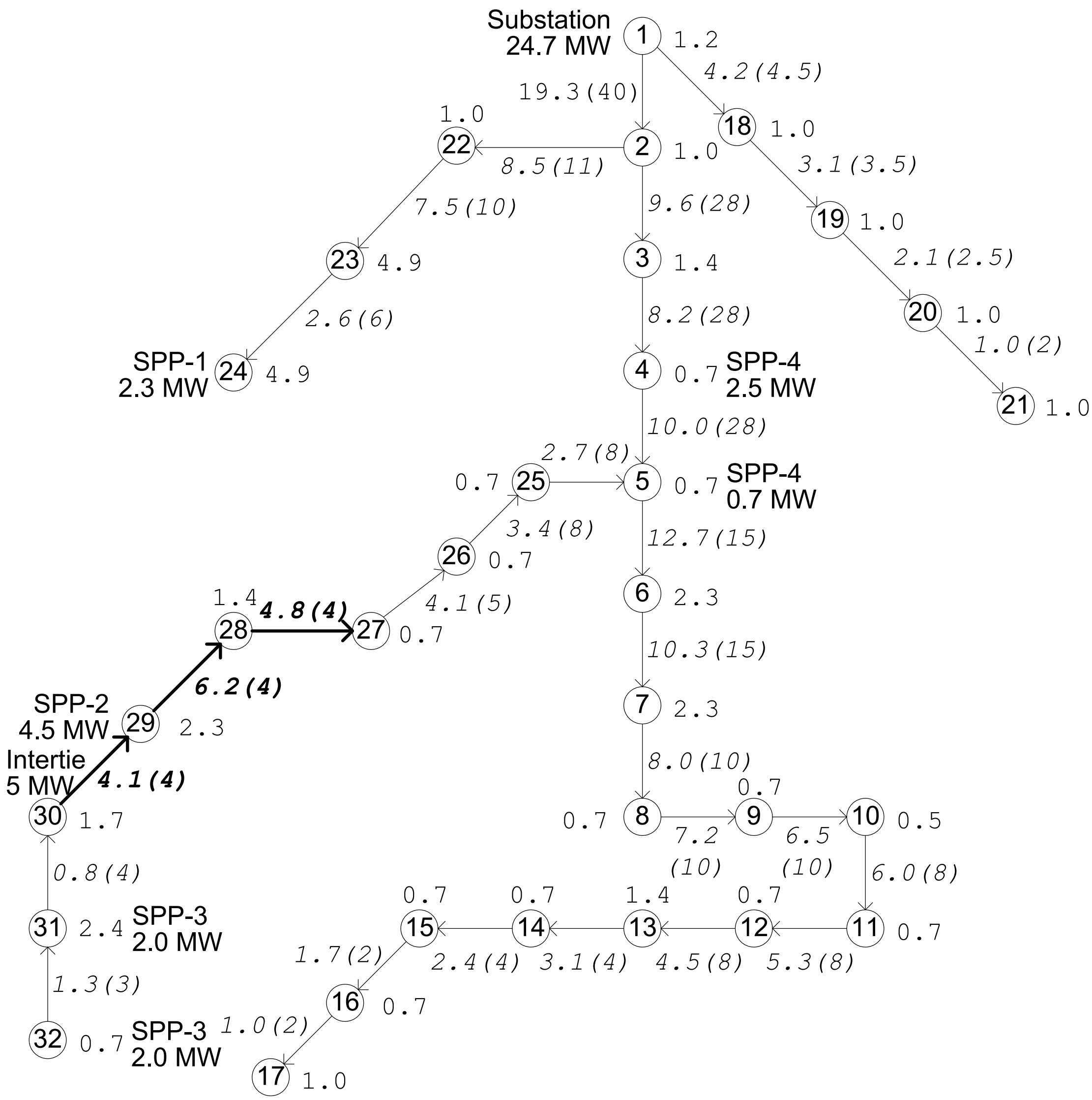

Figure 5.4: 32-Bus Radial Distribution System: SPP-DG as per initial proposals. The year-5 peak power flows are indicated beside each feeder, in MW. Bold lines indicate overloaded feeders.

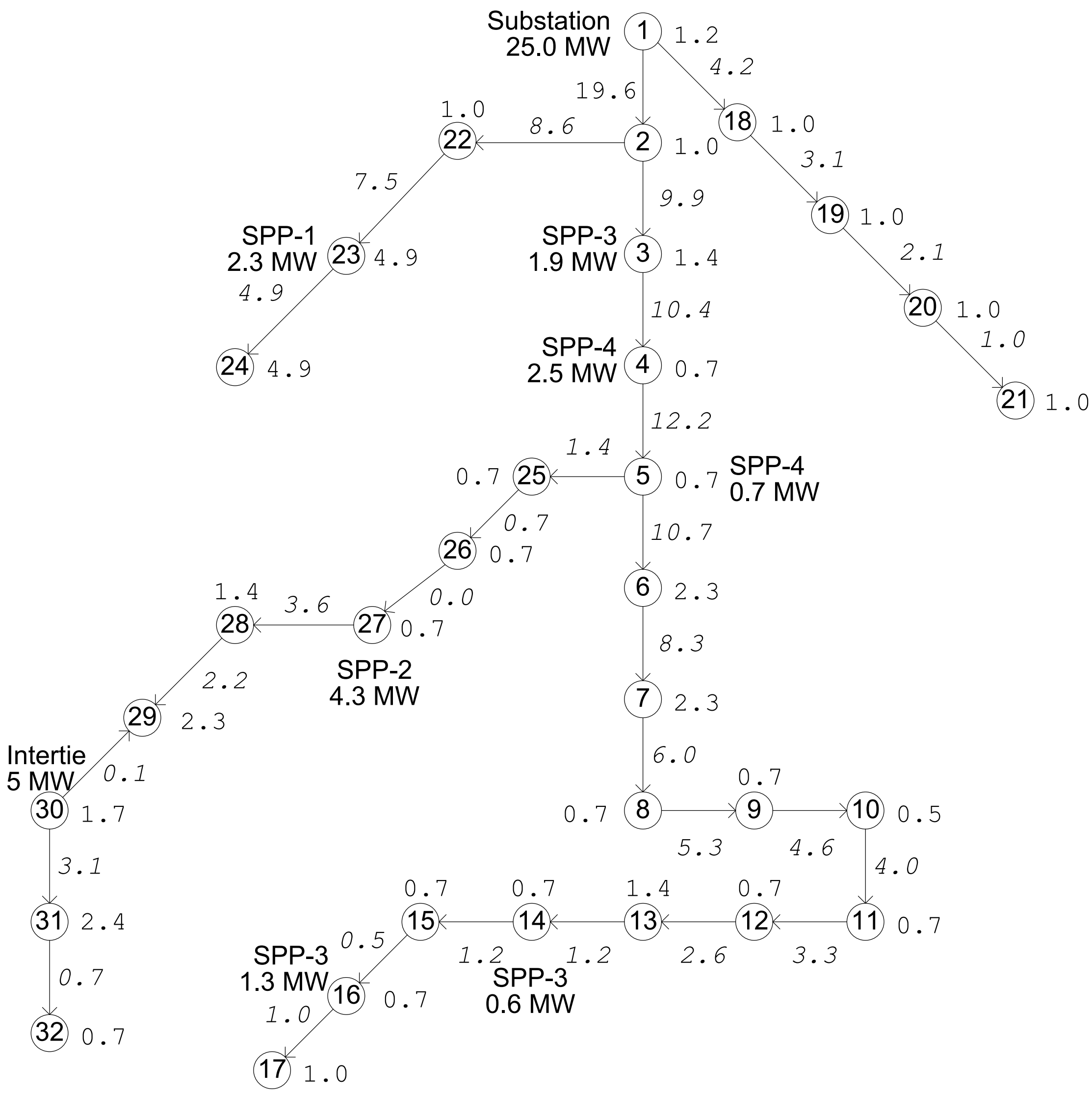

Figure 5.5: 32-Bus Radial Distribution System: SPP-DG as per Approved Proposals. The year-5 peak power flows are indicated beside each feeder, in MW.

Table 5.7: LDC's Import and SPPs' Production/Contract Schedules

Supply Element	Bus	Demand Level	Year/Supply (MW) 1	2	3	4	5
Substation (Import)	1	Base	3.62	3.92	3.80	4.15	4.52
		Intm	15.42	16.41	14.85	15.91	17.00
		Peak	23.25	24.44	22.41	23.67	24.97
Intertie (Import)	30	Base	1.39	1.67	1.75	2.00	2.26
		Intm	5.00	→	→	→	5.00
		Peak	5.00	→	→	→	5.00
SPP-1	23	All	2.30	→	→	→	2.30
SPP-2	27	All	4.31	→	→	→	4.31
SPP-3	3	Base	3.76	→	→	→	3.76
		Intm	2.82	→	→	→	2.82
		Peak	1.88	→	→	→	1.88
	14	Base	1.22	→	→	→	1.22
		Intm	0.91	→	→	→	0.91
		Peak	0.61	→	→	→	0.61
	26	Base	2.56	→	→	→	2.56
		Intm	1.92	→	→	→	1.92
		Peak	1.28	→	→	→	1.28
SPP-4	4	Base	-	-	0.50	0.50	0.50
		Intm	-	-	2.00	2.00	2.00
		Peak	-	-	2.50	2.50	2.50
	5	Base	-	-	0.14	0.14	0.14
		Intm	-	-	0.55	0.55	0.55
		Peak	-	-	0.69	0.69	0.69

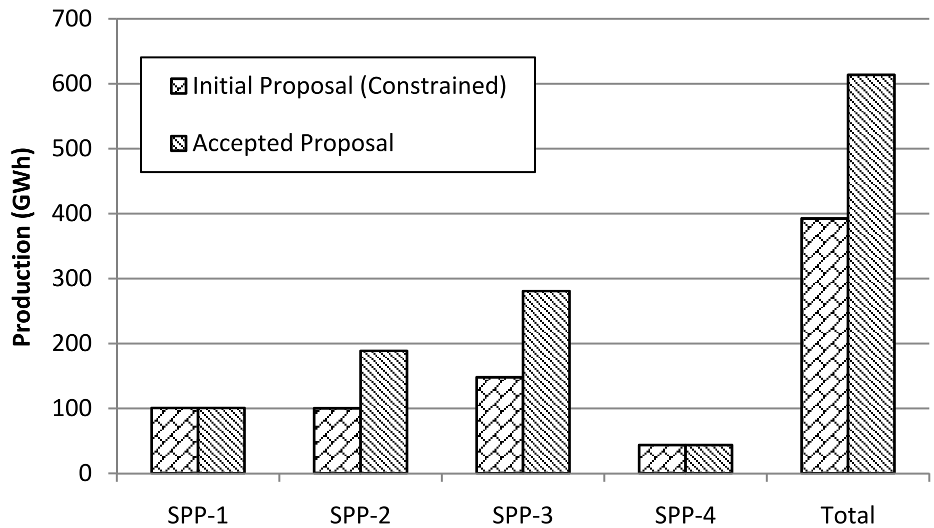

Figure 5.6: SPP Energy Production for Years 1-5

5.5.3 Impacts on the Distribution System

This section examines the impact of the DG-coordination framework on various aspects of distribution system planning. It compares the effect of the final, accepted SPP proposals versus the effects of the hypothetical, initial, constrained SPP proposals. The constraints applied to the initial proposals are those required for the system to be feasible, *e.g.*, feeder and voltage limits adhered to. The initial, constrained SPP proposal is the upper limit on participation, since it may not be technically or economically feasible for the DG unit to be so constrained.

Fig. 5.6 compares the total energy production of the initial and final proposals for each SPP over five years. The energy production of SPP_1 and SPP_4, whose production schedules went unconstrained through the process, is even. The DGCA's impact is demonstrated through SPP_2 and SPP_3, whose production increases significantly. Total additional SPP participation, made possible through the framework, increases more than 200 GWh. This production is possible due to the changes in DG unit siting by the DGCA, alleviating feeder overloads thus permitting increases in SPP production. This framework clearly and appreciably increases SPP participation, meeting an objective of this model.

Energy imported by the LDC, via the substation and intertie, are given in Fig. 5.7. As expected, imports are reduced considerably: 200 GWh over five years. By allowing the LDC to defer capacity upgrades, this could be of considerable financial benefit to the LDC.

Another possible benefit to the DG coordination framework is a reduction in losses (a byproduct of increased DG penetration). Distribution system losses, with no DG, DG units as per initial proposals (constrained), and accepted proposals, are given in Fig. 5.8. Note that losses are initially low because of the significant reactive power support provided by the numerous capacitors. Losses are reduced

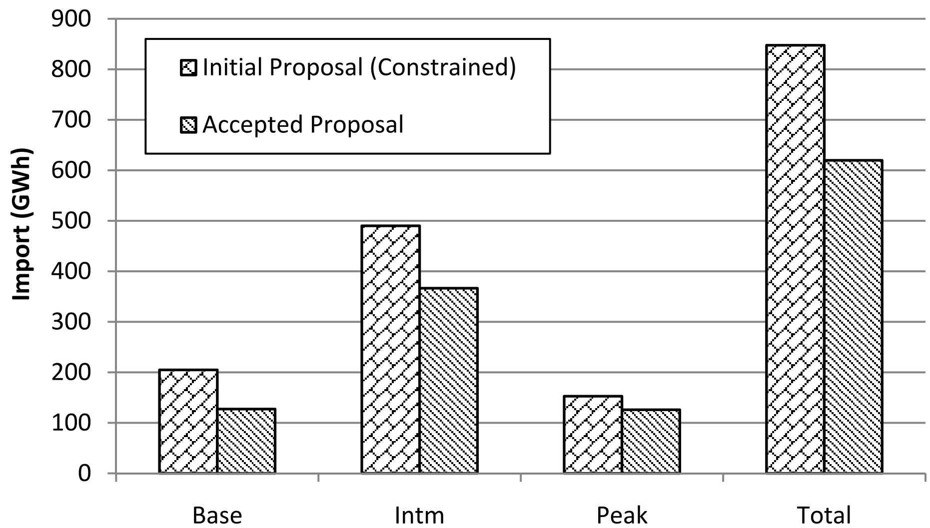

Figure 5.7: LDC Energy Import for Years 1-5

when DG units are introduced as per the initial proposal, and further reduced, by half, after the coordination framework is run.

Finally, the DGCA has a positive impact on the distribution system's voltage profile, as seen in Fig. 5.9. The additional DG unit production apportioned by the framework provides significant voltage support to the system.

5.6 Concluding Remarks

This chapter presents a framework for the coordination, by the LDC, of DG investments received from SPPs. The proposed framework, the DGCA, utilizes a feedback mechanism between the LDC and SPPs to maximize their participation and the penetration of DG units into the distribution system. Feedback, from the LDC, is in the form of production constraints which the SPP must adhere to. Obeying these constraints, it is left to the SPP to choose the best unit size, site, and production schedule to reach their objective, presumably, maximizing profit. The LDC makes use of the notion of commons and domains to isolate sources of feeder overloads and prioritize production constraints.

It is demonstrated, through a 32-bus test distribution system, that the framework is effective in improving the siting and sizing of DG units over a system with no coordination, allowing for a considerable increase in energy production. The framework, while also decreasing distribution system losses and improving its voltage profile, ensures technical constraints such as feeder and voltage limits are adhered to.

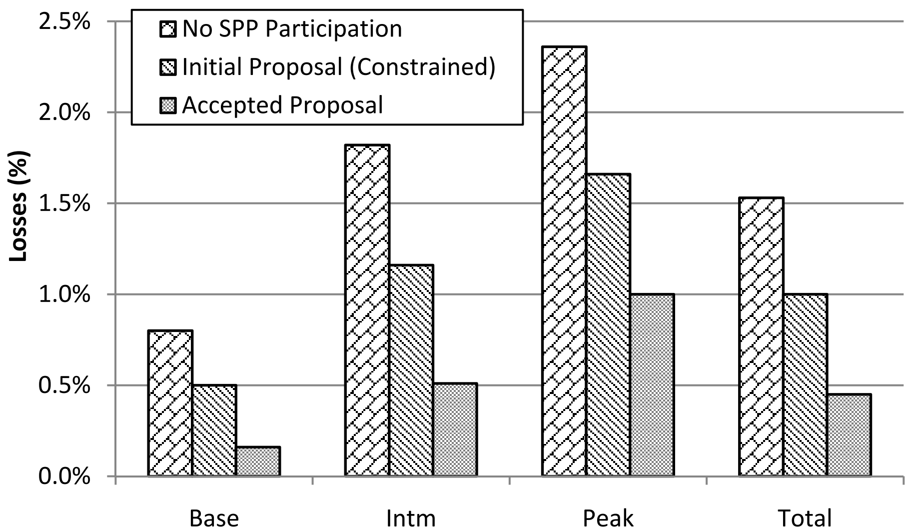

Figure 5.8: Distribution System Energy Losses for Years 1-5

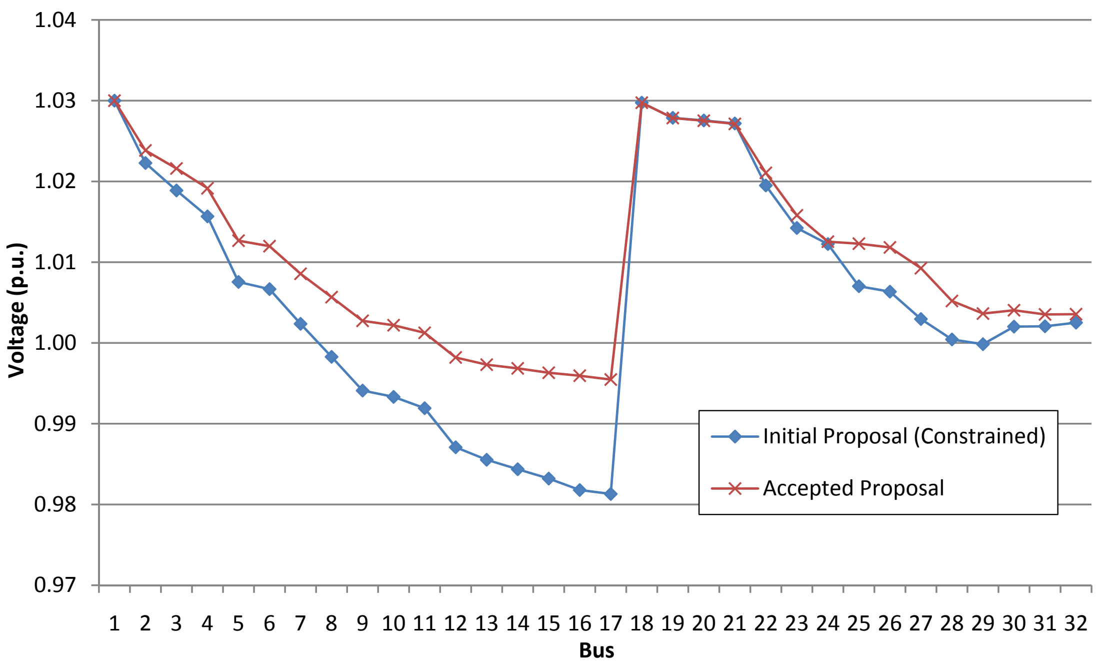

Figure 5.9: 32-Bus Radial Distribution System – Voltage Profile

Chapter 6

Conclusion

6.1 Summary

Policy shifts, together with advancements in DG, are forcing changes to the design and planning of distribution systems. This thesis examines distribution system planning in the context of these changes, specifically addressing the impact of investments in DG units by either LDCs or SPPs. In Chapter 1, the concept of the distribution system and its role in the bulk electric system in introduced. This is followed by an examination of the two major factors affecting its planning: DG technology and power industry deregulation.

In Chapter 2, a review of literature addressing distribution system planning is presented. It is observed that traditional planning methods are typically focused on minimization of infrastructure costs and losses subject to power flow, feeder, and substation constraints. However, deregulation has resulted in energy costs being considered alongside infrastructure costs, and additional DG supply alternatives added to substation options. Policy instruments used to encourage investment in clean and renewable energy sources, such as FITs, RECs/TGCs, and tender/bidding methods, is also reviewed in this chapter. FITs are found to be favoured in literature, although both FITs and RECs are widely used by governments.

A framework for the planning of distribution systems, from the LDC's point of view, is proposed in Chapter 3. The framework comprises two stages, the SPPM and the CPPM. The SPPM is responsible for determining the site and year of commissioning of future distribution system elements, whereas the CPPM is responsible for finalizing element sizing and production. The proposed framework will be of interest to both utility planners and policy makers. Planners can use this framework to plan capital investments and determine optimal energy production or contract schedules. Policy makers can use the framework, aided by a generalized approach to the modelling of policies, to formulate regulations that induce stakeholders to meet predefined goals.

Chapter 4 proposes a model for analyzing the long term effects of policies on DG investment within distribution systems, from the point of view of the regulator. A number of case studies are analyzed, including investment in an SPP-inclusive environment, where SPPs can invest in DG at market rates; investment in an SPP-friendly environment, where SPPs are offered incentives to invest in DG through FITs; and investment in a tightly regulated system, where the LDC is the only entity permitted to invest in DG (without incentives). All case studies are also subjected to cap-and-trade and carbon tax mechanisms. It is found that solely permitting LDCs to invest in DG is the most efficient policy. Correspondingly, FITs, especially at levels similar to Ontario's, are found to be a very expensive way to reduce carbon emissions. It is also found that uncertainty of carbon credit prices in a cap-and-trade system bore little risks to consumers (with regard to electricity price) and to governments (with regard to meeting emissions goals); however, CHP producers do bear some risk.

A framework that LDCs can use to coordinate SPP-DG investment proposals, the DGCA, is proposed in Chapter 5. Composed of four modules, the DGCA verifies the feasibility of proposals; if a proposal is not feasible, it works with SPPs, via feedback, to resize or relocate proposals within the distribution system. It is demonstrated that employing the DGCA can significantly increase SPP-DG investment and production, as well as decrease system losses and improve voltage profile (when compared to a system with no coordination).

6.2 Main Contributions of Thesis

The main contributions of the research presented in this thesis are as follows:

a) A comprehensive, two stage framework for the long term planning of distribution systems is proposed, bridging the gap between traditional distribution planning frameworks and methods for siting DG within the distribution system. The framework is fully dynamic and determines parameters for planning considering multiple distribution system elements; it can be used to site and/or consider both LDC and SPP-DG units.
b) The two stage framework, generic in nature, can be used by both the LDC to set long term plans and by regulators to analyze the effects of policy directives.
c) A new modelling framework is proposed for analyzing the effect of FITs, carbon taxes, and cap-and-trade mechanisms on LDC and SPP-DG investments within the context of distribution systems. The proposed model can be used by regulators to assist in predicting the effect of policies and consequently determine their ideal formulation.
d) The effect of FITs on DG investments by SPPs, on different technologies, are addressed. Capacity growth, emissions impacts, cost to consumers, and effectiveness of incentives are discussed.

e) Carbon taxes and cap-and-trade mechanisms, in combination with FITs, are analyzed and discussed within the context of programs proposed and in effect in Ontario, Canada.
f) A novel method for the coordination of SPP-DG investment proposals is presented in the thesis. This method, the DGCA, proposes using feedback between the LDC and participating SPPs, and the concept of domains and commons, to maximize DG investments in the distribution system while maintaining system operational feasibility.
g) It is demonstrated that the coordination of SPP-DG proposals within the LDC controlled distribution system is necessary to increase DG penetration and realize the loss reduction and voltage profile benefits of DG.

6.3 Lessons Learned

Through the process of conducting the research presented in this thesis, many challenges have been encountered and lessons learned.

6.3.1 Computational Issues

Computational issues played a large role in the development of the models and methods presented in this thesis. Ideally, a model should be as detailed and accurate as possible; however, it was quickly realized that many compromises are necessary in order to make the proposed models computationally feasible.

The dynamic modelling of distribution system planning is an onerous task. In real-life, physics and economics ideally require the use of integer variables and non-linear equations for modelling; yet computational and OR resources limit the size and type of problems solved. In this work, the trade-offs centered on the modelling of power flows and reactive power elements. Preferably, they would have been included in the models in this thesis; however, such inclusion would have necessitated a much more complex model that would have been difficult to solve.

To set appropriate trade-offs, it was necessary to ask 'what the goals of the model' were and, subsequently, what degree of accuracy was needed (*i.e.* how good does the solution have to be?). In the work presented in Chapters 3 and 4, the goals were focused on both economic and technical details. In order to achieve the goals and maintain feasibility of the work, assumptions were made (such as unity power factor). Such assumptions will impact the degree of accuracy of the subsequent solution, and should be checked if they are in keeping with meeting the goals of the work. In this case, leaving out reactive power was felt to be a necessary, and permissible, step to meet feasibility requirements of the model. The goal of providing methods for distribution system planning and policy design, given a deregulated environment, is still met.

Finally, the question of 'what solution is good enough?' has been raised in the development of this thesis. With limited computational resources, achieving a globally optimal solution to a MIP or non-convex NLP is difficult (and hard to prove). Given the uncertainties present and degree of accuracy in the data, it is felt that achieving a near-optimal solution is acceptable.

6.3.2 Evolution of the Distribution System

Another challenge encountered during this research was building models adaptable to policies governing the development of distribution systems that not only widely vary between jurisdictions, but also constantly evolve. For example, British Columbia and Ontario both offer feed-in-tariffs to SPPs to encourage DG investment, but BC's tariff is not based on technology [100]. In Ontario, the program rules are constantly evolving: tariff rates are frequently adjusted and/or eligibility requirements changed.

This thesis uses data from Ontario's SOP which was offered in 2008; in 2009, however, the SOP was replaced by the Feed-in-Tariff program, which offers different but similar incentives. These constantly changing rules required that an overarching principle of generality be observed for the research presented in this thesis. As far as possible, the models were designed to be adaptable to the wide range of policies and regulations possible.

Regulations and policies are not the only variables in distribution system design and planning. The distribution system itself is rapidly evolving, especially now, with the introduction of DG and smart grid technology. On the horizon may be the wide-spread penetration of plug-in electric vehicles, which may further drive changes to the planning of distribution systems and its development. The work presented in this thesis, being general, can accommodate some of these changes.

However, research on such planning methods as presented cannot remain stagnant; it is intended that the work presented will form the basis for future research. For example, issues surrounding the procurement of ancillary services may drive future planning and design models. The penetration of DG, together with smart grid penetration, may require future planning models to include the operational aspects of the distribution system, necessitated by the intermittency of generation, for example, or the load shaping opportunities now granted through smart metering.

6.4 Directions for Future Work

Further research can be conducted based on the work presented in this thesis. Some ideas are presented below:

a) The long term planning of large, network-configured distribution systems using mathematical programming techniques remains a formidable task. Instead of the heuristic approach that is used in this thesis to verify feeder sizes in network-configured systems, an implementation into the SPPM's framework can be done and is left to future work.
b) In this thesis, parameters, such as market prices, future capital costs, and SPP investments, etc. are assumed to be deterministic; however, in future research these may be considered as uncertain. Consequently, stochastic optimization, or robust programming techniques, can be applied to the two-stage framework and policy analysis model to mitigate the effects of this uncertainty.
c) It is assumed in this thesis that SPPs act independently; gaming and collusion amongst SPPs are not considered. However, the vulnerabilities of the DGCA to instances of gaming needs to be investigated and the DGCA (or the rules permitting SPP participation) need to be adjusted accordingly.
d) The possibility that SPPs may not follow through with their DG unit proposals is not considered. How this impacts the DGCA, and the resulting vacancies it may leave in the system, needs to be examined.
e) One method of coordinating DG investments is through financial incentives or disincentives. The use of such mechanisms to be used in conjunction with the DGCA can be investigated.
f) It may be useful to examine the role that SPP-DG units have providing ancillary services (such as reactive power) and consider them in determining optimal placement.

APPENDICES

Appendix A

Additional 32-Bus Radial Distribution System Data

Table A.1: Active and Reactive Loads [86][a]

Bus	P (p.u.)	Q (p.u.)
1	1.00	0.60
2	0.90	0.40
3	1.20	0.80
4	0.60	0.30
5	0.60	0.20
6	2.00	1.00
7	2.00	1.00
8	0.60	0.20
9	0.60	0.20
10	0.45	0.30
11	0.60	0.35
12	0.60	0.35
13	1.20	0.80
14	0.60	0.10
15	0.60	0.20
16	0.60	0.20
17	0.90	0.40
18	0.90	0.40
19	0.90	0.40
20	0.90	0.40
21	0.90	0.40
22	0.90	0.50
23	4.20	2.00
24	4.20	2.00
25	0.60	0.25
26	0.60	0.25
27	0.60	0.20
28	1.20	0.70
29	2.00	6.00
30	1.50	0.70
31	2.10	1.00
31	0.60	0.40

[a]The data has been scaled to suit the requirements of the case studies.

Table A.2: Feeder Parameters [86][a]

Bus-A	Bus-B	R (1×10^{-4}, p.u.)	X (1×10^{-4}, p.u.)
1	2	3.076	1.567
2	3	2.284	1.163
3	4	2.378	1.211
4	5	5.110	4.411
5	6	1.168	3.861
6	7	4.439	1.467
7	8	6.258	4.617
8	9	6.514	4.617
9	10	1.227	0.406
10	11	2.336	0.810
11	12	9.159	7.206
12	13	3.379	4.448
13	14	3.687	3.282
14	15	4.656	3.400
15	16	8.042	10.74
16	17	4.567	3.581
1	18	1.023	0.976
18	19	9.385	8.457
19	20	2.555	2.985
20	21	4.423	5.848
2	22	2.815	1.924
22	23	5.603	4.424
23	24	5.590	4.374
5	25	1.267	0.645
25	26	1.773	0.903
26	27	6.607	5.826
27	28	5.018	4.371
28	29	3.166	1.613
29	30	6.080	6.008
30	31	1.937	2.258
31	32	2.128	3.308

[a]The data has been scaled to suit the requirements of the case studies.

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