Eidgenössische Technische Hochschule Zürich
Swiss Federal Institute of Technology Zurich

Centre for Energy Policy and Economics
Department of Management, Technology, and Economics

Andrew Daniel James Stiel

Modelling Liberalised Power Markets

Master's Thesis Report

Centre for Energy Policy and Economics
Swiss Federal Institute of Technology Zurich (ETH Zürich)

Prof. Dr. Thomas F. Rutherford

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"I shall make electricity so cheap that only the rich can afford to burn candles."

Thomas Edison

"And God said, 'Let there be light' and there was light, but the Electricity Board said He would have to wait until Thursday to be connected."

Spike Milligan

Abstract

The power market of the state of New South Wales in Australia is currently facing a number of challenges that are typical of most liberalised power markets. These challenges relate to the uncertain effects of policies aimed at addressing issues such as climate change as well as the implementation of new technology options that have the potential to alter the underlying operating philosophy of the network. Therefore, the introduction of new policies and technologies need to be made with an ex-ante understanding of the implications for power market outcomes in order to correctly achieve whole-of-system benefits, maintain competitive behaviour and provide equal opportunities for behavioural change to all participants. Economic modelling of power markets with a consideration of physical power flows and system limitations is a powerful analytical method for gaining insight into their complexity and understanding the consequences of policy or technological changes.

This thesis describes the development of an economic model that is capable of accounting for real network power flows. The model is designed in such a way that a number of policy and technology options can be readily implemented and their market consequences can be assessed. To demonstrate its use, the power market of the state of New South Wales in Australia has been used as a test case. Three policy and technology options were assessed. Specifically, the implementation of locational marginal pricing, the application of a carbon price and the installation of distributed generators in the City of Sydney were simulated. Model simulations under perfect competition and Cournot Oligopoly competitive frameworks were also undertaken in order to demonstrate and investigate the impact of and potential for generating firms to behave strategically.

Model simulations indicate that the state of New South Wales can achieve significant benefits by applying a more liberalised spatial pricing mechanism. If these benefits are to be realistically realised, it is important to effectively define single price zones. The application of an economy-wide carbon tax, results in a reduction in carbon dioxide emissions from the generation sector as intended. However, given New South Wales' carbon-intensive generation profile, this reduction in emissions is driven in the short term by a reduction in demand and not a substitution toward lower carbon-intensive technologies. With respect to mitigating transmission congestion, the benefits of installing distributed generators in the City of Sydney are clear. The carbon emission reduction benefits of these generators are not obvious without a model that is able to account for the secondary heat market that these generators create. With a limited number of generating firms in New South Wales, there is potential for Cournot Oligopoly strategic behaviour. An increase in the number of generating firms results in market outcomes approaching that of perfect competition. The opportunity for strategic behaviour among generating firms is dependent on the pricing mechanism.

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Contents

List of Figures

List of Tables

List of Symbols

Abbreviations

AC	Alternating Current
AEMO	Australian Energy Market Operator
BAU	Business-As-Usual
CCGT	Combined Cycle Gas Turbine
CHP	Combined Heat & Power
CoS	City of Sydney
CSIRO	Australian Commonwealth Scientific and Industrial Research Organisation
DC	Direct Current
DG	Distributed Generation
DWL	Dead Weight Loss
EU	European Union
FBMC	Flow-Based Market Coupling
GAMS	General Algebraic Modeling System
GC	Gold Coast
IEA	International Energy Agency
ISO	Independent System Operator
LMP	Locational Marginal Pricing
MCP	Mixed Complementarity Problem
NEM	National Electricity Market
NSW	New South Wales
NTNDP	National Transmission Network Development Plan
OCGT	Open Cycle Gas Turbine
PV	Photovoltaic
QLD	Queensland
SWQLD	South West Queensland
TFP	Total Factor Productivity
VIC	Victoria

Model Sets

c	Transmission circuit
f	Firm
i	Generator
l	Transmission line
n	Node
s	Load segment

Model Parameters

ϵ	Price elasticity of demand [-]
$\eta_{i,\%}$	Generator heat rate [-]
$\eta_{i,fuel}$	Generator heat rate [-]
$carb_i$	Carbon emissions [t CO_2/MWh_e]
$d^o_{n,s}$	Benchmark network demand [MWh_e]
$ecap_f$	Firm total annual carbon emissions [t CO_2/yr]
$em_{com,i}$	Combustion emissions [kg CO_2/GJ fuel]
$em_{fug,i}$	Fugitive emissions [kg CO_2/GJ fuel]
$fcap_i$	Load factor [-]
$flow_l$	Power flow along a transmission line [MW_e]
$gcap_i$	Nominal capacity [MW_e]
$load^o_s$	Total network demand [MWh_e]
loc_n	Node location [Lat., Long.]
p^o_s	Benchmark network price [$/$MWh_e$]
pf_i	Fuel cost [$/GJ fuel]
pop_n	Node population [-]
$ptdf_{l,n}$	Power transfer distribution factor [-]
$srmc_i$	Short-run marginal cost [$/$MWh_e$]
t_{seg}	Time per load segment [hrs]
$tcap_l$	Transmission line capacity [MW_e]
$tcap_{l,c}$	Transmission circuit nominal capacity [MW_e]
vc_i	Variable cost [$/$MWh_e$]
$volt_{l,c}$	Transmission circuit nominal voltage [kV]

Model Variables

$\Omega_{f,s}$	Firm market share [-]
P_s	Price [$/$MWh_e$]
$P_{av,s}$	Single (average) network price [$/$MWh_e$]
$P_{hub,s}$	Market clearing price [$/$MWh_e$]
$PC^+_{l,s}$	Shadow price of congestion – positive direction [$/$MWh_e$]
$PC^-_{l,s}$	Shadow price of congestion – negative direction [$/$MWh_e$]
PE_f	Shadow price of firm carbon emissions [$/t $CO_2 \cdot h$]
$PF_{f,i,n}$	Shadow price of load factor [$/$MW_e \cdot h^2$]
$PG_{f,i,n,s}$	Shadow price of generation capacity [$/$MWh_e$]
$PT_{n,s}$	Transmission congestion fee [$/$MWh_e$]
$Q_{n,s}$	Node demand [MW_e]
$X_{f,i,n,s}$	Generation [MW_e]
$Y_{n,s}$	Node net-injection [MW_e]

Chapter 1

Introduction

As part of its *Sustainable Sydney 2030* vision, the City of Sydney has proposed the construction of a network of distributed generators in various locations around the city centre. These distributed generators are premised upon more efficient use of energy resources, reductions in greenhouse gas emissions, reductions in water use for generating electricity, security of supply, and mitigation of peak congestion of transmission lines into Sydney. This plan will help achieve the city's commitment to a 70 percent reduction in 2006 greenhouse gas emissions by 2030.

This proposal is a typical example of a technology option that is available to liberalised power markets. Its stated aims reflect the attitude of many liberalised power markets seeking to continue their reform toward better allocation and use of generation and transmission services in an increasingly sustainable way.

In order to provide a more complete picture of these reforms, this section outlines many of the characteristics of liberalised power markets. It details some of the challenges facing the three broad groups of markets participants – consumers, system operators and generators – and indicates some of the available policy and technology options for addressing these challenges. Particular reference is then made to the state of New South Wales (NSW) as a specific case of a power market seeking to implement policy and technology options to improve market outcomes. The section examines three options for NSW:

1. A changed pricing mechanism that better reflects the temporal and spatial costs of delivering electricity

2. The implementation of a carbon price to correct for the environmental externalities associated with the emission of greenhouse gases

3. The introduction of distributed generators in the City of Sydney – a transmission constrained area – to alleviate congestion, reduce carbon emissions and service secondary heat markets.

The section concludes by outlining the attributes of an economic model of a liberalised power market that has been developed to assess these policy and technology options and shows how it can be applied to the power market in NSW.

1.1 Characteristics of Liberalised Power Markets

Electricity is a strictly homogeneous product, which means that opportunities for product differentiation and associated price variation are non-existent. Instead, price differences occur in a power market due to the fact that, for all intents and purposes, electricity cannot be stored. Therefore, electricity must be consumed the instant that it is generated. Coordination among market participants is necessary to ensure a constant balance between the supply and consumption of electricity within the physical limitations of a transmission system.

Price differences will also occur in a power market on account of real power flows approaching the current carrying capacity of a transmission or distribution line. This real flow of power in a network is not trivial; it involves a complex interaction between the spatial injection and withdrawal of power and the inability to store electricity within a network at any point in time. Accounting for real power flows increases the complexity of an economic model but is essential to correctly simulate market outcomes. Section 2.5 provides a more detailed description of the reasons for and consequences of accounting for real power flows in an economic model.

The generation, transmission and distribution of electricity relies on highly capital-intensive technologies. This characteristic results in slow rates of structural change within a network in response to policy reforms. Power market stakeholders require firm assurance that stated policy changes will be implemented and retained over the long term. They also require a detailed understanding of the consequences of policies in order to plan investment and operation strategies in response to these changes.

A liberalised power market has three broad interdependent sectors; consumers, system operators and generators. Liberalisation efforts have already seen a separation of generation and transmission participants to limit vertically integrated strategies and to facilitate competition and more market-oriented management of electricity assets. In addition to vertical separation, these sectors face other common challenges, which are primarily concerned with but not limited to the following:

- Managing growing demands on all physical systems
- Ensuring security of supply; not only from the point of view of system adequacy but also from the point of view of continued access to (or substitution away from) current energy conversion fuels
- Correctly pricing many of the externalities currently associated with the generation, distribution and use of electricity. This is particularly true of environmental externalities such as carbon emissions and consumption of scarce water resources
- Refining the design and operating philosophy of electricity networks in light of recently available technologies and in anticipation of future technologies

- Designing markets and infrastructure plans that best reflect whole-of-system costs and benefits. That is, proposed changes, upgrades and extensions should reflect net social welfare improvements by considering the whole network, not just individual sectors. To achieve this, all participants should be exposed to the same price signals and have access to the same opportunities to adjust behaviour

- Mitigating opportunities for participants to exert market power at the welfare expense of other participants.

In addition to these common challenges, there are sector-specific characteristics. A good understanding of these sectors and their interactions is important in order to continue improving power markets.

1.1.1 Consumers

Consumers in a power market typically have low short-run elasticity of demand. In other words, the consumption patterns of consumers do not change rapidly when exposed to price changes because there are limited opportunities to immediately substitute for electricity use. At a household level, electricity demand can be attributed to the use of electrical appliances. The cost of electricity for operating these appliances is typically quite small relative to the purchase cost of the appliance. Changes in the price of electricity may influence consumer decision behaviour in the purchase of subsequent appliances over the long term, but there will be little change in the short term. In the short term, consumer behaviour is more strongly influenced by environmental factors such as the weather and incidence of light (Lijesen, 2007). Industrial users also have limited short term substitution options with their demand attributed to capital-intensive and durable assets.

In most power markets, domestic end-use consumers are not directly exposed to price volatility. Instead there is an intermediate retailer that purchases electricity in bulk from wholesale spot markets and on-sells it to individual end-use consumers at a fixed predetermined single or dual-tariff rate.[1] In this sense, consumers are not empowered with the appropriate price signals and information to adjust their consumption patterns based on the true cost of electricity. This limits the extent to which consumers will identify opportunities for efficiency measures or load-shifting their bulk use to off-peak periods. Ultimately, this results in inefficient market outcomes and higher whole-of-system costs than would occur in an ideal market.

Furthermore, electricity prices for consumers are largely independent of location. Most markets have large single price regions that do not reflect the spatial cost of delivering electricity. This results in further inefficient market outcomes, incorrect price signals for investment in generation and transmission and, consequently, higher whole-of-system costs.

As power markets consider options to meet continued growth, consumer or demand-side management offers the greatest potential for implementing efficient alternatives to network augmentation (Dunstan, 2011). Recognition that demand response offers a viable resource for improving market outcomes should

[1] For very large industrial uses, direct purchases from wholesale markets are usually possible.

act as a driver for future market reforms looking to position supply and demand options as equivalent resources (Hogan, 2010). Consumer characteristics, in addition to technological developments have led to the following demand-side policy and technology options:

- Dynamic pricing[2] to reflect the temporal cost of delivering electricity
- Locational Marginal Pricing (explained further in Section 2.1) to reflect the spatial cost of delivering electricity
- Smart grid technologies that provide the potential for a system operator to communicate with and control the use of domestic appliances in peak periods in exchange for compensation for affected customers
- Smart meters to implement dynamic and locational pricing mechanisms
- New efficient-use technologies capable of reducing electricity use without affecting consumer behaviour
- Market-driven incentives to adjust behavioural use of electricity leading to load-shifting benefits
- Improved access to market information particularly in a dynamic pricing setting.

1.1.2 System Operator

A transmission and distribution network is highly capital-intensive with declining marginal costs of output. Such conditions favour the formation of electricity networks as natural monopolies. Therefore, the system operator of an electricity network is government-regulated to limit the exercise of monopoly market power. The system operator usually takes the form of an independent, zero-profit entity known as the Independent System Operator (ISO) with regulated revenue caps to cover system operation costs and approved network investments.

The day-to-day role of the ISO is to manage the interaction and coordination of market participants by providing indiscriminate access, clearing the market and ensuring that the system remains within the bounds of its physical limitations. Across regulatory periods, the ISO performs additional tasks such as network maintenance, and the planning and deployment of new network investments to meet growing demands, replace ageing infrastructure, ensure network security, manage anticipated changes in generation and consumption patterns, and deploy new beneficial technologies as they become available. An ISO must first seek regulatory approval for any new network investments and consequent increase in revenue demands to make these investments. This process requires proposed investments to be justified through individual project business cases that demonstrate how the proposal achieves its stated aim as the least-cost option. The regulatory rules governing the functions of the ISO are designed to encourage holistic system benefits over the long term without bias toward generators, consumers, retailers or other stakeholders.

Management of any monopoly is a difficult task that requires constant adaptation. Some of the challenges and policy and technology options facing system operators of power markets are as follows (Zhao et al., 2009):

[2] Also referred to as time-of-use pricing.

- Allocating transmission capacity in a way that reflects the true cost of doing so within the physical limitations of the network and the market rules governing the power market. Such allocation should reflect the temporal and spatial cost of delivering electricity to customers
- Designing market incentives and sending correct price signals to manage congestion as alternatives to network investment
- Making investments in smart grid technologies and understanding how these investments are likely to affect system operation. Smart grid technologies include dynamic metering and smart meters that permit system operator control over domestic appliances
- Managing and understanding changed market conditions with increased disaggregation of pricing zones and the advent of dynamic metering and carbon pricing policies
- Planning network upgrades that account for the increase in expectations relating to network security. N-1 and often N-2 level network adequacy is currently considered the industry norm
- Managing changing load patterns as society increases its rate of substitution into electricity. The growth in electric car use is one such example that has the potential to alter load patterns
- Implementation and refining of tools to manage spot market fluctuations, such as secondary markets for 'spinning reserve', correctly managed capacity payment systems or grid-level storage technological solutions as they become available
- Identifying and taking opportunities to make scale-efficient network connections that reflect likely changes to generation portfolios; these include more numerous and smaller generators in increasingly remote locations
- Managing the increased penetration of intermittent and more unpredictable sources of electricity with consequences for bidding processes, market and network balancing, and price volatility
- Managing a transition toward more sophisticated revenue-cap determinants such as Total Factor Productivity (TFP) methods. These methods aim to encourage monopolies to function according to industry best-practice and not just marginal improvements in their current performance, which may be lagging industry
- Improving the transparency of markets and access to information for all participants.

1.1.3 Generators

Generation assets are capital-intensive, often spatially grouped, irreversible, durable and have long lead times. They are also typically characterised by a low short-run elasticity of supply. This property is two-fold:

1. Generators are limited in terms of how quickly they can adjust their capacity output in any given instant. Large thermal generators typically have slow ramp rates, while some hydro generators can very quickly adjust electrical output to match demand patterns. The speed and extent to which a given generator can adjust output has value to a system operator looking to manage the balance between generation and demand at any instant to maintain a suitable frequency range.

2. Generators are ultimately limited in their maximum electrical output by their nominal capacity rating. An increase in nominal capacity is a significant investment of money and time.

Given the above properties and the fact that electricity is strictly homogeneous, with no product differentiation possible, there are significant barriers to entry into the generation market. This means that there are often very few participants on the supply side of an electricity market, which results in instances of market power. In these situations, generating firms are able to make use of their oligopoly positions to influence market outcomes to the detriment of other participants.

The generation market is also faced with much investment uncertainty in the context of carbon pricing, fossil fuel prices and government policies toward nuclear energy, renewable energy, energy security, and centralised and decentralised grid philosophies. Therefore, the outlook for generation portfolios is quite uncertain, especially considering the large potential for technological change and innovation with respect to renewables and smaller generation technologies. Stimulating investment in new generation technologies and managing the perceived risks in doing so must be considered in the context of the benefits such investments provide.

Decentralised philosophies for generation have the potential to further alter the electricity sector. For example, small-scale distributed generators, such as gas-fired Combined Heat and Power (CHP) plants[3] located in capacity constrained areas, can mitigate transmission congestion in peak periods, in addition to servicing secondary markets such as heat and absorptive chilling. Likewise, the increasing use of solar photovoltaic (PV) systems has interesting consequences for dispatch scheduling in peak periods, given that these periods typically coincide with instances of high solar irradiation and solar PV output.

To this end, there are a number of policy and technology opportunities in the generation sector of liberalised power markets:

- Firm government policies and business certainty with respect to carbon pricing
- Realisation of the benefits of decentralised generation philosophies
- Economic and financial instruments to stimulate investment in new technologies with environmental and energy security benefits
- Correctly valuing reserve capacity, security of supply and generation flexibility, particularly with the increased penetration of intermittent energy sources.

[3] Also commonly referred to as Combined Cycle Gas Turbines (CCGT).

1.2 The NSW Electricity Network

Many of the challenges facing liberalised power markets that have been discussed in the preceding sections apply directly in New South Wales (NSW). The following are among the specific features of the NSW network that drive technology and policy options:

- Transmission distances are vast. With rapid growth in demand, options to defer, reduce or eliminate investment in transmission and distribution are valuable. Network costs already make up 51 percent of the retail electricity bill in the state of NSW (see Figure 1.1).[4] This figure is expected to rise on the back of approved transmission and distribution network investment in the NSW region to the value of $17.1 billion or 80 percent of the current regulated asset base (Australian Energy Regulator (AER), 2010).

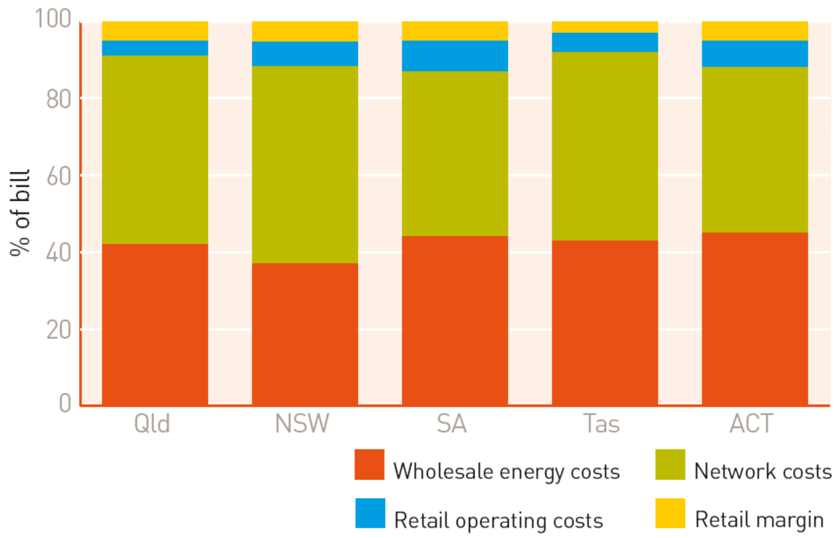


Figure 1.1: Composition of Retail Electricity Bills for 2010 in the Australian NEM by Region (Australian Energy Regulator (AER), 2010)

- The Australian NEM and NSW generation portfolios largely consist of fossil-fuel-powered thermal stations, the majority of which are coal (see Figure 1.2). In light of carbon pricing policies, generators (and ultimately consumers) are vulnerable to much higher electricity prices that reflect the environmental damages caused. At the time of this writing, the Australian Federal Government was negotiating terms to pass legislation to implement a carbon tax with a view to a future emissions trading scheme. The Garnaut Climate Change Review 2011, commissioned by the Australian Government, recommends this tax take on an initial value of $26/t CO_2 (Garnaut, 2011).

[4] By comparison, network costs comprise an average of 42 percent of retail electricity bills among European Union (EU) member states (Eurostat – Environment and Energy, 2010).

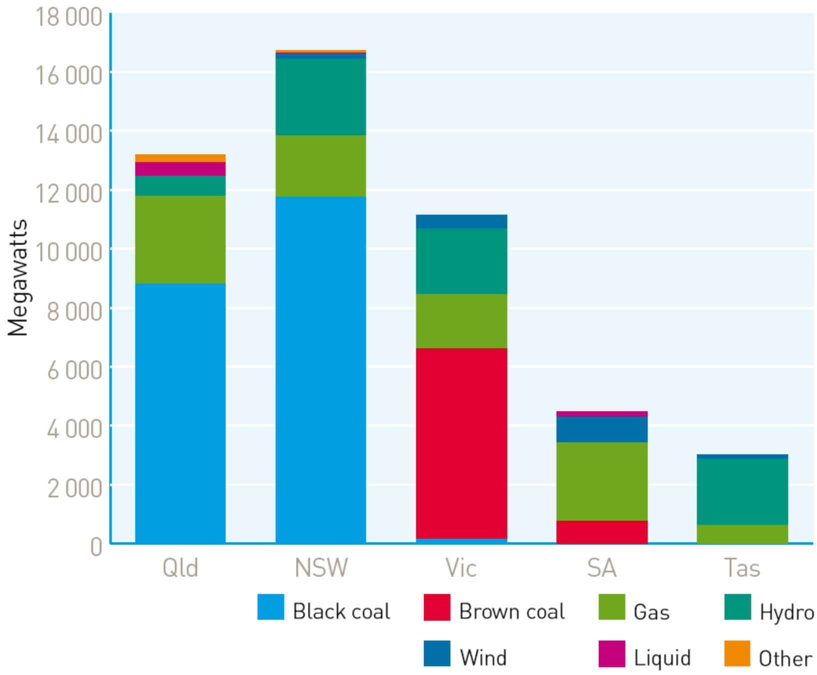


Figure 1.2: Generation Portfolio of the Australian NEM by Region (Australian Energy Regulator (AER), 2010)

- A small number of firms control NSW's entire generation portfolio, with only five firms accounting for 95 percent of market share by registered capacity (see Table 1.1). This ownership structure has the potential for oligopoly strategic behaviour. In times of congestion, generators are reported to have deliberately exercised market power by submitting mispriced bids.

Table 1.1: Market Share by Capacity of Generating Firms in NSW (Australian Energy Regulator (AER), 2010)

Firm	Market Share [%]
Macquarie Generation	30
Delta Electricity	28
Eraring Energy	18
Snowy Hydro	14
Origin Energy	4
TRUenergy	3
Redbank Project	1
Marubeni Australia	1
Others	1

1.2.1 City of Sydney Distributed Generation Proposal

With a generation portfolio dominated by large centralised thermal power stations, NSW is also considering more decentralised generation technology options. A specific example of this is the recent proposal by the City of Sydney to install distributed generators in the centre of the city in order to satisfy stated sustainability, network management and energy security aims. These distributed generators have been labelled as 'trigeneration' facilities for their ability to not only deliver power to the grid, but also to meet the heat and absorptive chilling (heat-driven cooling) requirements of surrounding buildings. The plan details specifics pertaining to the type, size, location and thermal pipe network for these trigeneration plants, in addition to a proposed deployment timeline. Specifically, a number of combined cycle reciprocating gas turbines ranging in size from 4 MW_e to 40 MW_e will be installed between 2010 and 2030, with a final total combined capacity of 360 MW_e (Kinesis Consortium, 2010).

1.3 Thesis Outcomes

As alluded to above, liberalised power markets involve a complex interaction between the consumption, system operation and generation sectors. Changes to the structure or functionality of one sector will impact other sectors, often in unforeseen ways. Therefore, it is necessary to have an ex-ante understanding of the true outcomes of implementing policy and technology options when trying to address the current challenges facing power markets.

To this end, this thesis has developed three tools for the analysis of a power market in order to directly assess many of the policy and technology options discussed:

1. An economic model of a liberalised power market with the following key features:
   (a) Modelling of real network power flows based on DC linear assumptions
   (b) Simulation of three end-use consumer pricing structures – a single network price, zonal pricing and Locational Marginal Pricing (LMP)
   (c) Application of a carbon price by way of a carbon tax or by defining a limit on the total emissions of generating firms
   (d) Simulation of a perfectly competitive market or a market in which generators act strategically based on output decisions according to a Cournot Oligopoly.
2. A tool for characterising a transmission network with the following key features:
   (a) Detailed specification of generator characteristics including nominal capacity, load factor, fuel price, heat rate and carbon emissions intensity (combustive and fugitive)
   (b) Detailed specification of transmission line characteristics including topology, circuits, nominal voltage and nominal capacity
   (c) Easy network structural changes to readily analyse the effectiveness of technology options.
3. A tool for aggregating benchmark load segments and corresponding prices into a representative load-duration set of a specified resolution.

These tools provide a range of options to test, in isolation and combination, real policy decisions that currently face power markets. They have been designed so that they can be applied using information that is usually publicly available. The tools have also been developed with the following factors in mind:

- Ease of understanding – the model is easily understood, transparent and accessible. Policy and structural changes are straightforward to make.
- Appropriate level of detail – the model is detailed enough to gain meaningful insight into any given change or combination of changes but not to such an extent that the effects of policy and technology changes are clouded by model complexity.
- Computational speed – simulation times are dependent on the defined network structure and the implemented model features but generally range from 30 to 90 seconds. The model can be prepared and run on most computers and operating systems.
- Expandable – additional features can easily be added to the model, where appropriate. Some suggestions for future improvements and modifications have been included in Section 5.1.

The language used to formulate the model was GAMS (General Algebraic Modelling System). GAMS was originally developed for economists at the World Bank as an intuitive language for economic policy analysis. The GAMS modelling environment provides access to a range of powerful solution algorithms for solving large-scale general purpose mathematical models (Rutherford, 1995). The present model was formulated as a Mixed Complementarity Problem (MCP). This class of problem is described in a paper by Rutherford (1995) that explains the extension of GAMS to include MCPs.

1.4 Modelling the NSW Electricity Network

The NSW electricity network is a single distinct region within the Australian National Electricity Market (NEM) and is connected to the regions of Victoria (VIC) and Queensland (QLD) by way of interconnector transmission lines. These interconnectors permit electricity trade among regions and the formation of a centralised pool market for the entire Australian NEM from which all transactions occur. The centralised pool market is operated by the Australian Energy Market Operator (AEMO). The NSW electricity network was selected to demonstrate the features and functionality of the developed model, network characterisation tool and load segment aggregation tool. All information and data applied were obtained from publicly available sources.

A model developed by the University of Queensland (2009) was used as a basis for the network topology structure. This model aggregates the NSW network into 16 nodes with two interconnectors to the Queensland network and one to Victoria. Figure 1.3 represents the network topology, the names of nodes, and the transmission lines connections. This figure also indicates the transmission capacity of each individual line, which was computed using the network characterisation tool and the allocation of individual nodes to pricing zones according to the geographical coverage of retailers. All values in this figure are in MW_e.

This same network topology can be seen in Figure 1.4, which is a Google Earth satellite image of the NSW region with all relevant nodes marked. As this image shows, the distances in NSW are vast and the population centres are located on or near the coast. Because the demand requirements west of Wellington are minimal, transmission to these areas has not been considered.

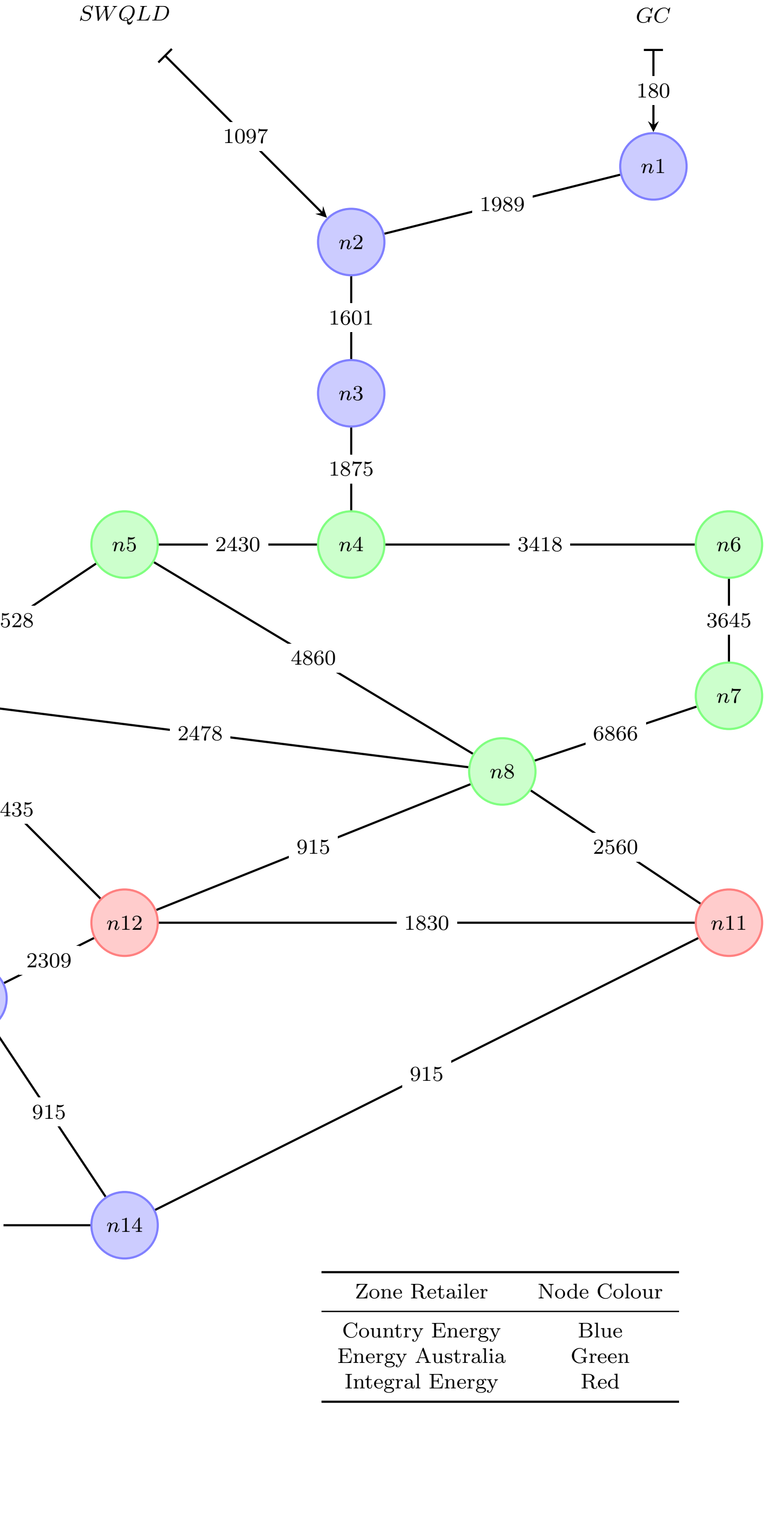
Table 1.2 provides a summary of the characteristics of each node including average demand and generation profile. Table 1.3 provides a list of each generating firm, its fuel types and benchmark carbon emissions cap.[5] For the purposes of zonal pricing, each of the 16 nodes has been placed into one of three zones according to the geographic coverage of the three retailers in NSW. These zones are shown in Table 1.4 and in Figure 1.3.

Figure 1.5 shows the load-duration curve for the region of NSW in 2010. The load data to generate this figure is publicly available from the website of the Australian Energy Market Operator (AEMO) (accessed April 18, 2011). It expresses regional load and price data for each 30-minute trading interval of the

[5] These firm emissions caps were determined by defining benchmark conditions in a model simulation and observing the total carbon emissions and firm electrical output. For further details see Section 3.2.

Figure 1.3: NSW Transmission Network Topology with Transmission Capacity

Node Label	Node Name
GC	Gold Coast
$SWQLD$	South West QLD
$n1$	Lismore
$n2$	Armidale
$n3$	Tamworth
$n4$	Liddell
$n5$	Bayswater
$n6$	Newcastle
$n7$	Central Coast
$n8$	Sydney
$n9$	Mt Piper
$n10$	Wellington
$n11$	Wollongong
$n12$	Marulan
$n13$	Yass
$n14$	Canberra
$n15$	Tumut
$n16$	Murray
VIC	Victoria



Zone Retailer	Node Colour
Country Energy	Blue
Energy Australia	Green
Integral Energy	Red

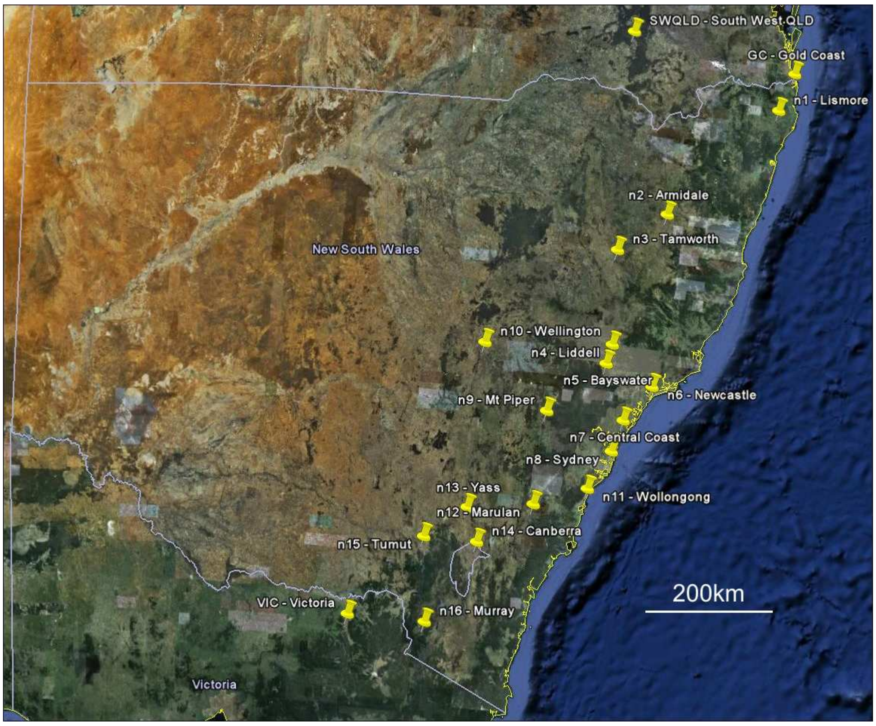


Figure 1.4: Satellite Image of NSW and Location of Nodes

Table 1.2: Average Benchmark Demand and Generation Profile by Node

Node	Average Benchmark Demand [MW_e]	Total Generation Capacity [MW_e]	Average Capacity Factor [-]	Average Emissions [t CO_2/MWh_e]
$n1$	286	–	–	–
$n2$	236	–	–	–
$n3$	320	–	–	–
$n4$	56	2150	0.862	1.090
$n5$	124	2690	0.901	0.991
$n6$	646	–	–	–
$n7$	390	5224	0.896	0.984
$n8$	5081	476	0.933	0.513
$n9$	222	2320	0.883	0.983
$n10$	150	–	–	–
$n11$	348	700	0.641	0.310
$n12$	169	–	–	–
$n13$	256	–	–	–
$n14$	423	–	–	–
$n15$	191	2860	0.300	0.171
$n16$	143	1560	0.095	0.000

Table 1.3: Fuel Types and Benchmark Annual Carbon Emissions by Firm

Firm	Fuel Types	Emissions [t CO_2/yr]
Macquarie Generation	Coal, Fuel Oil	22217
Redbank Project	Coal	1496
Eraring Energy	Coal, Hydro	16009
Delta Electricity	Coal, Gas	15273
Marubeni Australia	Gas	251
TRUenergy	Gas	2984
Origin Energy	Gas	23
Snowy Hydro	Hydro	–

Table 1.4: Zone Allocations of Nodes According to NSW Retailers

Retailer	Nodes
Country Energy	$n1$, $n2$, $n3$, $n13$, $n14$, $n15$, $n16$
Energy Australia	$n4$, $n5$, $n6$, $n7$, $n8$
Integral Energy	$n9$, $n10$, $n11$, $n12$

year. In 2010, the peak load segment had a demand of 13765 MW_e, with a yearly average of 8807 MW_e and annual regional consumption of 77.1 TWh_e.

To model the inclusion of distributed generators in the City of Sydney, up to six 50 MW_e CCGT generators with properties outlined in Table 1.5[6] can be readily added to the node represented by Sydney ($n8$). The network effects of these distributed generators, both in isolation and in combination with other simulated policy and technology options, can then be readily assessed to gain a realistic insight into their costs and benefits.

For more details on the specific information and assumptions used to characterise the NSW electricity network, refer to Chapter 3 and Appendix A.

[6]These properties are based on data for CCGT plants in NSW in the ACIL Tasman report prepared for the National Transmission Network Development Plan (NTNDP) (ACIL Tasman, 2009). More details can be found in Section 3.2 and Appendix A.

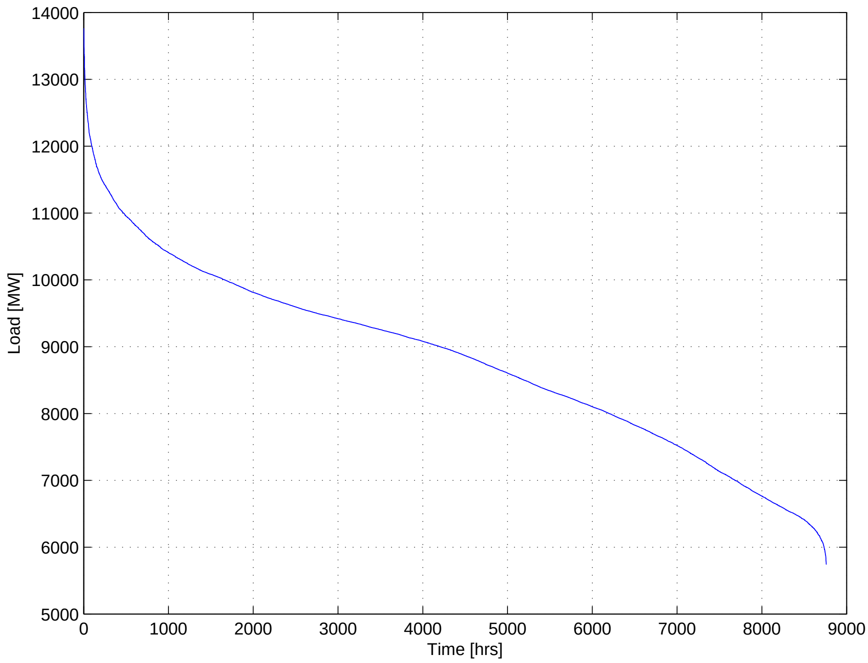


Figure 1.5: NSW Region Load-Duration Curve for 2010

Table 1.5: Properties of Simulated Distributed Generators in Sydney

Property	Value
Fuel	Gas
Type	CCGT
Total Number	6
Nominal Capacity ($gcap_i$)	50 MW_e
Thermal Efficiency ($\eta_{i,\%}$)	0.50
Fuel Cost (pf_i)	\$5.83/GJ fuel
Variable Costs (vc_i)	\$2.00/MWh_e
Combustion Emissions ($em_{com,i}$)	51.30 kg CO_2/GJ fuel
Fugitive Emissions ($em_{fug,i}$)	14.20 kg CO_2/GJ fuel
Load Factor ($fcap_i$)	0.920
Benchmark Emissions Cap ($ecap_f$)	321 t CO_2/yr

Chapter 2

Economic Model of a Liberalised Power Market

This section provides a detailed description of the economic model that was developed to analyse a liberalised power market. It first outlines the key features of the model before describing its logic.

2.1 Consumer Pricing Mechanism

A key feature of the model is the ability to adjust the pricing mechanism for consumers from a single network price to a location-dependent price. The location-dependent price is either Locational Marginal Pricing (LMP), where each node in the network has a different price, or zonal pricing, where individual nodes are grouped into single price zones. The following section discuss the details of these pricing mechanisms.

2.1.1 Single Network Price

Most power markets use a single network price for all nodes in the network, irrespective of whether they are located in a network constrained area at the point in time in question. In practice, electricity at each node in a network will have a different value in periods when transmission services need to be rationed. A single network price applies the generation-weighted average of these different prices uniformly to all consumers in the network. Therefore, consumers in non-congested areas of the network are subsidising consumers in constrained areas of the network by paying a higher price than their location characteristics determine. Consequently, consumers in these non-congested areas, which are exposed to a higher price, will consume less than they would otherwise, while consumers in the congested areas will consume more on account of their subsidised price.

In practice, implementing a single network price in the model is equivalent to allocating all nodes into a single zone and applying the zonal pricing framework, as discussed in Section 2.1.3.

2.1.2 Locational Marginal Pricing

In contrast to a single price for the entire network, Locational Marginal Pricing (LMP) allows a system operator to charge a locationally dependent price for electricity for each node in the network. Although a single network price is administratively simpler to implement, LMP is considered a more efficient pricing mechanism. It better recognises that electricity is not only a product at a point in time but also at a point in space with temporal and spatial variations in demand and therefore price (Krause, 2007).

Importantly, in periods with no transmission congestion in any part of the network, there will be no difference in the market outcome of a single network price or LMP mechanism. In this case, it is only the scarcity of generation services that determines the market price for electricity. However, in periods when transmission congestion exists, the system operator must ration this transmission scarcity by charging a higher price for consumers located in transmission constrained areas of the network. Consumers in these locations will be penalised for their consumption with a higher price, while generators will be rewarded for their favourable location with the same higher price.

By this logic, an LMP mechanism sends more correct and more transparent long term price signals to the economy for consumers to adjust consumption patterns and for generators to locate themselves in constrained areas. LMP also better indicates the worth of investing in additional transmission capacity in constrained areas (Weijde and Hobbs, 2011). In cases where the long term marginal cost of generation at a node is less than the transmission fee to that node, it makes more sense to increase generation capacity. Conversely, where the long term marginal cost of generation is more than the transmission fee, additional transmission capacity should be installed.

LMP maximises social welfare by optimising the allocation of generation and transmission services based on their location in the network. This is in contrast to a single network price, which inefficiently rations transmission resources in times of congestion, resulting in dead weight losses. Figures 2.1 and 2.2 both illustrate the difference between a single price and LMP mechanism during periods of network congestion. Figure 2.1 specifically refers to nodes that are not located in transmission congested areas, whereas Figure 2.2 specifically refers to nodes located at the end of a congested transmission line.

In both instances, the LMP price mechanism results in the efficient allocation of generation and transmission resources in such a way that demand is matched to the marginal cost of delivering electricity. As discussed above, however, under the single-price mechanism, non-congested areas will subsidise the higher cost of delivering electricity to congested areas by paying a higher price (P_{single}) and consuming less (Q_{single}) than under a LMP mechanism. This results in a dead weight loss (DWL) at this node, indicated by the area $A - B - C - D$ with $P_{single} - D - A - C - P_{LMP}$ representing the loss to consumer welfare in Figure 2.1. Conversely, for congested areas, consumers will benefit from the the single network price by paying a lower price (P_{single}) and consuming more (Q_{single}) than they would have if resources were allocated efficiently, as under a LMP mechanism. The area $P_{LMP} - A - C - D - E - P_{single}$ of Figure 2.2 represents the increase in consumer welfare at this node, with the area indicated by $A - B - C$ representing the DWL. The magnitude of the shift in consumer welfare between the congested and non-congested areas is equivalent

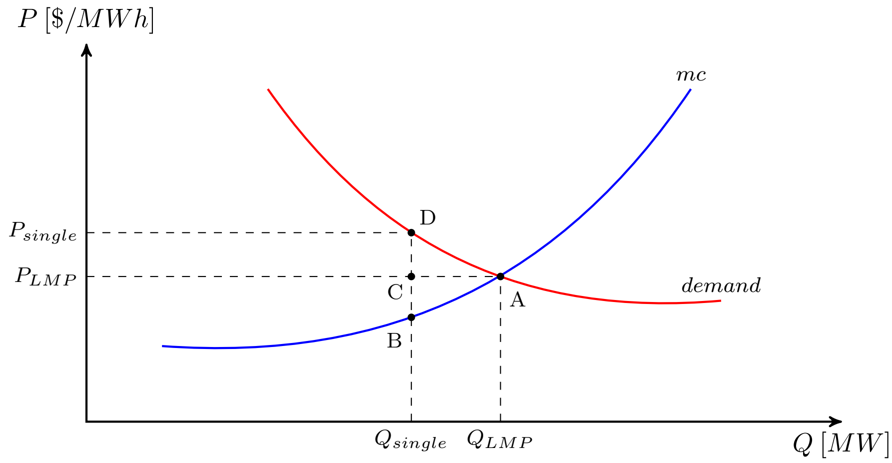


Figure 2.1: Single Network Price Dead Weight Loss – Non-Congested Area

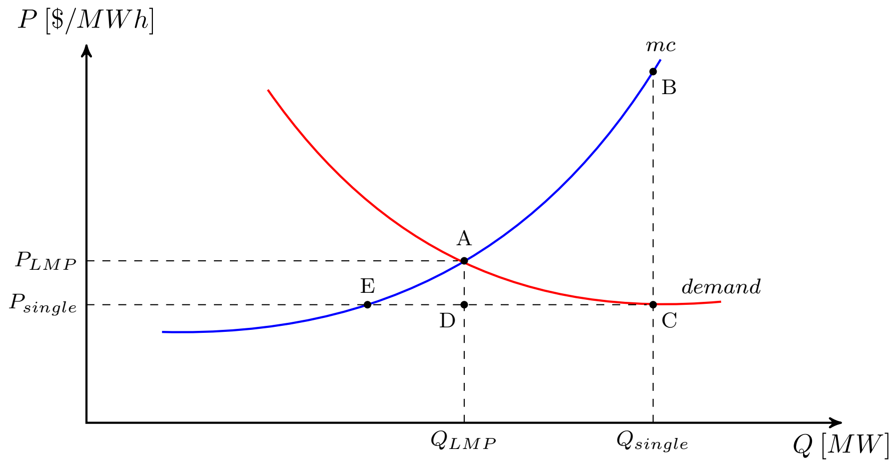


Figure 2.2: Single Network Price Dead Weight Loss – Congested Area

to the transfer in wealth resulting from the subsidies through the single price mechanism – the sum across all nodes is equal to zero. The total network DWL can be determined by summing the DWL at each individual node, as above. This represents the total irrecoverable loss in welfare for the network as a result of the inefficient pricing mechanism.

2.1.3 Zonal Pricing

Zonal pricing is a compromise between a single network price and LMP. Zonal pricing consists of single price regions based on a predetermined allocation of nodes to zones. As is the case with LMP, the difference between a single network price and zonal pricing is only apparent in times of congestion. During these periods, zonal pricing is a more efficient way to allocate transmission resources than a single network price according to the same principles as LMP. Allocating nodes to zones based on knowledge of constrained regions allows welfare benefits to approach those of LMP. To achieve this, zone allocation should be done with the aim of preventing internal network congestion within a zone. Instead, where network constraints exist, the zone boundaries should be defined with congested 'flowgates' connecting each of the zones. Many markets naturally implement zonal pricing using national boundaries as zone definitions, as is the case in much of Europe. In this model, a common market is still used to allocate generation and transmission resources, which makes it an example of a 'Market Splitting' pricing scheme. In Europe, where individual regional zones are still largely governed by independent markets, the market mechanism for trade among regions is referred to as 'Flow-Based Market Coupling' (FBMC) (Krause, 2007).

From a modelling perspective, the single network price is actually a special case of zonal pricing in which all nodes in the network are allocated to the same zone. From a conceptual point of view, these two pricing mechanisms will be treated as separate.

2.2 Carbon Accounting

Accounting for and pricing carbon emissions has been a major focus for recent policy debate. Such policies have significant implications for power markets, particularly those that are largely dependent on carbon-based fuel sources such as coal, oil and gas. Over the long term, appropriate carbon price signals may result in a substitution to cleaner and renewable sources of electricity. In the short term, a carbon price that correctly values the environmental consequences of emissions can alter the behaviour of generating firms and consumers; this necessitates its inclusion in an economic model of power markets.

This model allows for carbon emissions to be priced in two different ways: either by applying a fixed carbon tax per unit of carbon emitted or by capping the emissions of generating firms. In order to account for carbon emissions, each generator has a known emissions intensity based on emissions resulting from the direct combustion of the fuel and fugitive sources such as mining and transportation of the fuel.

Ordinarily, a carbon tax and an emissions cap would both result in the redistribution of wealth or revenue collected for the implementation of long term carbon abatement measures. However, this model has no mechanism for such wealth transfer. Consequently, a carbon price in this model simply results in a higher marginal cost of generation, the extent of which depends on the carbon emissions intensity of individual generators. This will therefore elicit a demand response but also a change in the generation mix for any given load segment as high carbon-intensive generators are priced out of the market in favour of lower intensive generators. Given that this model is static and does not account for long term changes in the marginal cost of services, an absence of wealth transfer for long term emissions reduction is a valid assumption.

2.2.1 Carbon Tax

The functioning principle of a carbon tax is that it allows policy makers to fix a price per unit of carbon emitted and allows the market to determine the total emissions quantity. Although it is easier to implement a carbon tax, it does not provide the same control over total emissions as an emissions cap. From an economic point of view, a carbon tax will generate revenue for the government, which can then redistribute this wealth to assist in carbon abatement over the long term. If the carbon tax is priced correctly and this redistribution of wealth occurs ideally, the outcomes of an emissions cap (with permit trading) and a carbon tax are identical. The carbon tax should be priced at the point at which the marginal cost of abatement equals the marginal benefit of doing so. Correctly identifying this point is the main challenge in implementing a carbon tax as a carbon emissions reduction policy instrument.

2.2.2 Emissions Cap

In contrast to a carbon tax, the functioning principle of an emissions cap is that it allows policy makers to define the total emissions permissible in an economy while allowing market forces to place a value on the right to emit.

This model applies an emissions cap by exogenously limiting the total allowable emissions for each generating firm over all load segments. With an emissions cap, each unit of carbon emitted by a firm takes on a value that is unique to that firm. Such a value exists as the emissions cap may prevent a firm from producing more electricity, where it would have in the absence of the cap. This value is known as the shadow price on firm carbon emissions (PE_f) and is a computed variable in the model. Based on the shadow price of firm carbon emissions (firm carbon value) for each of the firms, an economy-wide 'carbon price' can be determined, which indicates the price at which emissions would be traded in a carbon market. This 'carbon price' is calculated as the generation-weighted average of the value that each firm places on carbon emissions:

$$P_{carbon} = \frac{\sum_{f,i,n,s} PE_f t_{seg} \cdot X_{f,i,n,s} t_{seg}}{\sum_{n,s} Q_{n,s}}$$

In a carbon market, where permits for emissions can be traded, firms with a carbon value greater than the carbon price ($PE_f t_{seg} > P_{carbon}$)[1] will purchase emission permits at the carbon price for the right to increase their emissions limit. Conversely, firms with a carbon value lower than the carbon price

[1] PE_f has modelled units of \$/t $CO_2 \cdot$ h.

($PE_f t_{seg} < P_{carbon}$) will sell permits, recognising that the value of the revenue from the permits is greater than that of the foregone revenue from being limited further in their total electrical output. In this way, the total emissions of a sector can be defined with reductions taking place at the least cost.

A carbon market arranged like this is known as a cap-and-trade scheme and is a functioning or proposed carbon reduction policy for many countries and regions. Correctly defining emissions caps for each firm is key to their effectiveness and remains a considerable challenge in their implementation and management.

This model does not include an active emissions permit trading market. However, it does reveal to each firm the value of emitting carbon for a given emissions cap and, therefore, provides insight into a possible permit trading price, were such a market to exist.

2.3 Competitive Framework

This model is capable of simulating two distinct frameworks that govern competition in the market: perfect competition and a strategic environment in which generators act according to a Cournot Oligopoly. A difference in the competitive framework can occur by way of the capacity bidding behaviour of generators. As Section 2.6.2 discusses further, generators submit capacity bids to the system operator, which makes a proportion of their total nominal capacity in any given load segment available for dispatch. The competitive framework governs how generators submit capacity bids to the market place and the consequences of such action for market clearance.

The capacity to adjust the competitive framework from perfect competition to a strategic environment is a useful analysis tool for policy makers looking to promote a balanced power market. For instance, a change in the pricing mechanism may provide additional strategic opportunities from which generating firms can profit. The ability to test such changes in the context of strategic and idealised market places is useful for policy makers seeking to limit strategic opportunities and encourage fair competition.

A brief description of perfectly competitive and Cournot Oligopoly markets in the context of power markets is included below. For further details on the economic principles governing these competitive frameworks, see Appendix B.

2.3.1 Perfect Competition

The perfect competition framework describes an idealised market in which all participants are price takers, which means that they do not attempt to make use of market power. Within this framework, the market clearing price occurs when the marginal cost of production equates to demand. In the context of a power market, the marginal cost of the marginal generating unit determines the market clearing price for any given load segment. To illustrate this, consider the simplified power market depicted in Figure 2.3. In this example, the marginal generator is $i = 5$. Consequently, the market clearance price P^* is equal to the marginal cost of this generator (mc_5) with an equilibrium quantity of Q^* transacted.

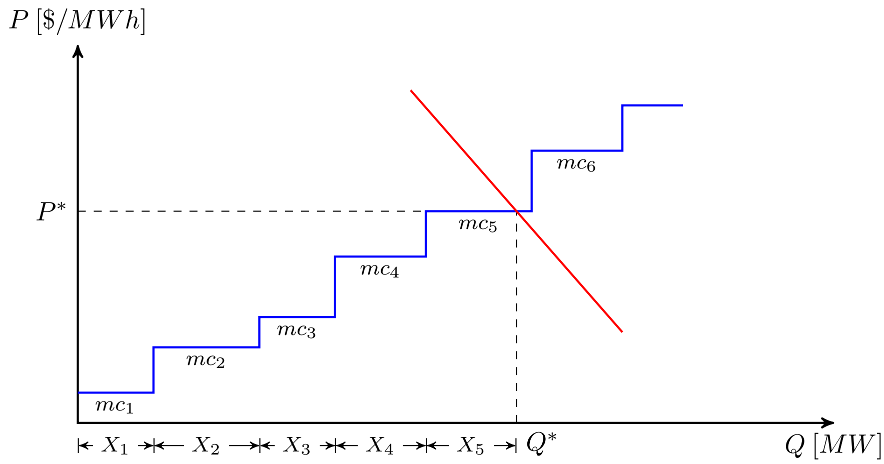


Figure 2.3: Determination of the Market Clearing Price

Appendix B.1.1 provides a more detailed description of the principles of Perfect Competition theory.

2.3.2 Cournot Strategic Behaviour by Generators

Under a Cournot Oligopoly framework, generating firms are permitted to act strategically by submitting capacity bids that may make use of market power. This differs from a perfectly competitive market, in which generators making capacity bids only consider their physical limitations (discussed further in Section 2.6.3). Under the Cournot Oligopoly framework, generating firms may have an incentive to reduce their capacity bids and consequently provoke a higher marginal cost generator to meet consumer demands. In doing so, all generators are rewarded with a higher price than would have been observed in a perfectly competitive market. Figure 2.4 helps illustrate this concept. If any or all of the generators were to submit reduced capacity bids to the market, the marginal cost curve would shift to the left (represented by the dashed blue line) and require the subsequent marginal generator to clear the market at a higher equilibrium price $P' = mc_6$ with lower equilibrium demand Q'.

Appendix B.1.2 provides a more detailed description of the principles of Cournot Oligopoly theory.

2.4 Network Structural Changes

This model is static in that it does not permit changes in the network structure for any given simulation. Over time, the investment in new generation or transmission capacity in strategic areas of the network is not possible. However, it is still interesting to assess how a power market adjusts to changes in its structure. Testing the effectiveness of different technology options is of interest to policy makers looking to improve systems. Therefore, although the ability to change the network structure is not a direct feature of the model, in that there is no associated variable, the model syntax has been organised to facilitate the

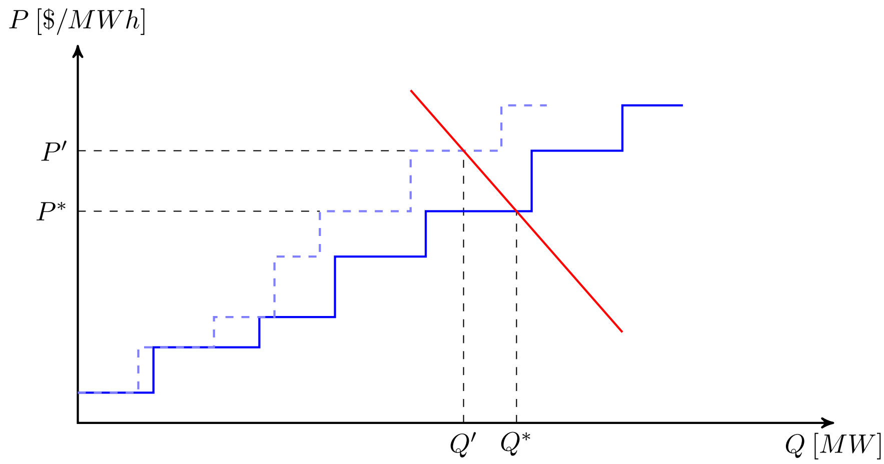


Figure 2.4: Effect of a Cournot Oligopoly – Strategic Capacity Bids

ease of including or removing different technologies from the network for direct comparison of simulation results.

An example of how this can be used would be to test the effectiveness of small-scale distributed generators located at the end of a constrained transmission line. Distributed generators could be used in this setting to satisfy peak periods of demand, which would eliminate, reduce or defer the need for additional investment in transmission capacity. Such generators can also have additional benefits, including lower carbon emissions and providing for secondary markets, such as heat in close proximity to the generator. The model syntax allows such technologies to be easily included or removed in order to compare results and realise the true value of some of these benefits realised. This approach could apply to all types of generators, as well as increased transmission capacity or new transmission connections.

2.5 Real Power Flows

Although this is largely an economic model, the inclusion of physical characteristics is important in order to correctly analyse market outcomes. In particular, the real power flows within the network have consequences that cannot be captured by simply modelling supply-demand equilibrium at each node. Therefore, the inclusion of real power flows in an economic model recognises that electricity is a product that is not only consumed at a specific time, but also at a specific location in the network. The delivery of electricity at any given location is not trivial and is highly dependent on power flows in other areas of the network. In periods of high demands, this delivery can come at a cost that must be accounted for in a realistic model of a power market.

Power will flow along the path of least resistance in a network. This path may not necessarily be that of the shortest distance; it is more dependent on other physical characteristics of the line, such as circuit reactance and capacity. Furthermore, because electricity must be consumed in the instant that it is generated (storage of electricity for future consumption is not possible[2]), all power injected must be withdrawn somewhere. This complex interaction between node injections and withdrawal of energy makes visualisation and anticipation of real power flows in a network impossible. In order to model this interaction effectively, it is necessary to include the principles of Power Flow Analysis. This model uses Power Transfer Distribution Factors (PTDFs) that are based on DC Linear approximations to the Power Flow Equations. PTDFs indicate the fraction of power flow along any given line in the network to any given injection-withdrawal transaction. Including PTDFs in the economic model allows real power flows and their market consequences to be approximated.

Section 3.3 provides further details on the factors affecting real power flows and their computation and inclusion in the economic model. See Section 3.3.3 for a specific example that illustrates the use and significance of PTDFs.

2.6 Model Logic

This section details the logic governing the model. The model logic can be represented by consumer demand, system operator conditions and generator conditions. Appendix A provides a detailed list and description of all model variables, parameters, sets and data. In this model description, variables are always listed as upper-case letters and parameters listed as lower-case letters. Sets are subscripted.

This model has been formulated as a Mixed Complementarity Problem (MCP). A description of this class of problem can be found in a paper by Rutherford (1995). Only the numbered equations in the following sections are included in the model. The 12 model equations can be additionally identified by the inclusion of their associated complementarity slack variable, as indicated by the $\perp$ symbol. The GAMS code specific to the model of the NSW transmission network can be found in Appendix C.1.

2.6.1 Consumer Demand

Electricity consumers are assumed to operate according to a linear calibrated demand schedule with constant price elasticity of demand across all nodes and load segments. In this sense, consumers face time-of-use pricing and adjust their behaviour patterns according to the price elasticity of demand. In practice, few networks actually employ time-of-use pricing for end consumers. Instead, most employ a single or dual-tariff (on-peak and off-peak) pricing structure for end consumers, with an intermediate retailer exposed to the fluctuations in market price. This model uses time-of-use pricing with the recognition that there will be a move toward dynamic pricing in electricity markets as the use of smart meters becomes more widespread. The linear demand schedule is as follows:

$$Q_{n,s} = d^o_{n,s}\left[1 - \epsilon\left(\frac{P_s}{p^o_s} - 1\right)\right] \qquad \perp Q_{n,s} \tag{2.1}$$

where $P_s = P_{z,s}$ in the case of a single network price or zonal pricing and $P_s = P_{n,s} = P_{hub,s} + PT_{n,s}$ in the case of Locational Marginal Pricing (LMP).

[2]This is still true of pumped storage systems or batteries that convert electricity to mechanical and potential or chemical energy when ‘storing’.

The price elasticity of demand is given by ϵ.

It is necessary to calibrate the demand schedule with benchmark load and price data. These data are often publicly available from the websites of transmission system operators or energy regulators in the form of historical market data.

When a zonal pricing mechanism is applied to consumers, the zone price is based on the demand-weighted average of all location-dependent prices ($P_{hub,s} + PT_{n,s}$) in that zone and is determined according to Equation 2.2. Note that the single network price is also calculated using Equation 2.2, with the additional condition that all nodes are allocated to a single zone.

$$P_{z,s} = \frac{\sum_{n \in z} Q_{n,s}(P_{hub,s} + PT_{n,s})}{\sum_{n \in z} Q_{n,s}} \qquad \perp P_{z,s} \tag{2.2}$$

2.6.2 System Operator Conditions

There is a single system operator for managing the clearance of the market and ensuring that the transmission network operates within the bounds of its physical limitations. In this case, the system operator is an independent and zero-profit entity. The literature refers to a system operator of this type as an Independent System Operator (ISO). Essentially, the ISO has two functions:

1. Clearance of the market according to the least-cost dispatch based on capacity bids by generators

2. Management of the physical transmission network such that the capacity limitations of transmission lines are not breached.

To do this, the ISO operates a centralised power market pool in which all generators are mandated to sell their generation services to the ISO, who clears the market according to the least-cost dispatch. No bilateral trades between generators and consumers are possible in this market model. Instead, generators make capacity bids to the ISO, who on-sells these services to consumers until total generation matches total demand. Conceptually, this pool market can be visualised as in Figure 2.5.

When determining the least-cost dispatch, the ISO recognises that electricity is a product that is consumed at a specific time and location in the network. Therefore, the least-cost dispatch has two components; the marginal cost of generation services[3] to determine a market clearing price and the allocation of transmission resources where they become scarce.

Market Clearance

A key feature of the model from the perspective of the ISO, is that there is perfect access to information. That is, the ISO has complete knowledge of the marginal cost of production for every generator in the network and clears the market accordingly. Generators do not place price bids as they would in a real power market. Instead, the market clearing price is determined as the marginal

[3]The components that make up the marginal cost of generation services are discussed in more detail in Section 2.6.3.

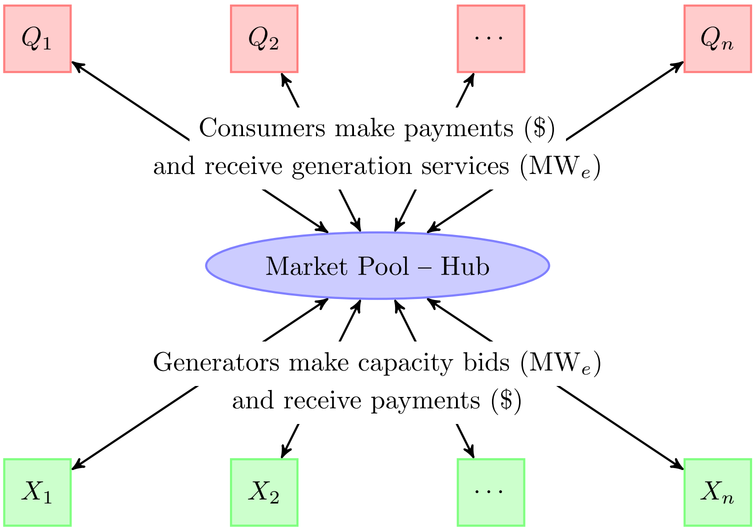


Figure 2.5: Pool Market Model

cost of the marginal generating unit, as illustrated in Figure 2.3. This point occurs when the total network generation equals the total network demand in each load segment. Therefore, a network level energy balance establishes the market clearing price $P_{hub,s}$ as follows:

$$\sum_{f,i,n} X_{f,i,n,s} \geq \sum_{n} Q_{n,s} \qquad \perp P_{hub,s} \tag{2.3}$$

Although generators cannot make price bids, like the ISO, they also have complete access to information and make capacity bids to maximise profits. In other words, in any given load segment, a generator will make available to the ISO a fraction of its nominal capacity, which may be less than its total nominal capacity depending on the generator's physical constraints and the competitive framework. The ISO then clears the market based on the magnitude of these capacity bids. The size of these capacity bids can be seen in Figure 2.3 as the width of X_i. As discussed in Section 2.3.2, under a Cournot Oligopoly strategic framework, generating firms may have an incentive to submit capacity bids of a magnitude less than their physical limitations allow in order to provoke a higher market clearing price.

Rationing Transmission Scarcity

In transmission-constrained scenarios, the ISO prices scarce transmission resources in such a way that net-transmission into a node n includes a capacity cost of constrained transmission lines. This shadow price of the transmission constraint or capacity cost along a single transmission line is determined by the ISO as follows:

$$tcap_l \geq \sum_{n} ptdf_{l,n} Y_{n,s} \qquad \perp PC^{+}_{l,s} \tag{2.4}$$

$$\sum_{n} ptdf_{l,n} Y_{n,s} \geq -tcap_l \qquad \perp PC^{-}_{l,s} \tag{2.5}$$

The positive and negative $PC_{l,s}$ terms recognise that the transmission constraint must be satisfied in both directions along the transmission line such that $-tcap_l \leq flow_l \leq tcap_l$ where $flow_l = \sum_n ptdf_{l,n} Y_{n,s}$. This capacity cost will only ever exist in either the positive or negative direction, not both.

For a given node n located at the end of a capacity constrained line l, the net-injections into a node ($Y_{n,s}$) are determined by rationing capacity scarcity as follows:

$$\sum_l ptdf_{l,n}(PC^+_{l,s} - PC^-_{l,s}) = PT_{n,s} \qquad \perp Y_{n,s} \tag{2.6}$$

In rationing transmission scarcity, the ISO performs an energy balance at the node level whereby the net-injection of electricity into a node equates to the demand less the generation at that node for each load segment. This node-level energy balance determines the transmission fee ($PT_{n,s}$) into that node.

$$Y_{n,s} = Q_{n,s} - \sum_{f,i} X_{f,i,n,s} \qquad \perp PT_{n,s} \tag{2.7}$$

It should be noted that for any given transmission line, there will only be a transmission fee when the line is operating at its capacity limit. As discussed in Section 2.1, the market consequences of this fee depend on whether the network is operating according to a single network price, zonal price or LMP. In the case of a single price, all transmission fees are averaged and shared among all market participants according to Equation 2.2 for a single zone. In LMP scenarios, the price at a node reflects the transmission fee by directly applying it in addition to the market clearing price such that $P_{n,s} = P_{hub,s} + PT_{n,s}$. In this way, generators located in transmission-constrained areas are rewarded with a higher price, while consumers in the same area are penalised. The market consequences for zonal pricing will be somewhere between that of a single network price and LMP, depending on the allocation of nodes to zones.

Given their complete access to information, under a Cournot Oligopoly framework, generating firms are also able to profit from transmission constraints by adjusting their capacity bids in ways that provoke congestion and higher prices in favourable areas. For instance, a generating firm spread across multiple locations may be able to act strategically by limiting the output of one generator, which would force other generators in the network to increase output to satisfy demand. This may result in capacity constraints and higher prices in areas that favour the firm that is acting strategically. The use of market power to provoke capacity constraints and favourable prices reputedly occurs in California and will remain a challenge for liberalised power markets with small instances of market power (Cohen et al., 2004).

2.6.3 Generator Conditions

Individual generators and generating firms are subject to a number of physical limitations that characterise their operation in the network. These specifically include the following:

1. Individual generators are constrained by a nominal capacity ($gcap_i$) that cannot be exceeded at any point in time. This constraint results in a

shadow price of generation capacity ($PG_{f,i,n,s}$) or capacity rent. The capacity rent term has units \$/MWh$_e$.

2. Individual generators are constrained by a load factor ($fcap_i$) that limits the total electrical output across all load segments, in addition to the limitation resulting from the nominal capacity constraint. This requires generators to make temporal decisions by considering all load segments to determine the most profitable dispatch. In this sense, generators have ex-ante knowledge of the demand profile across all load segments and knowledge of how they can maximise their profits accordingly.[4] This constraint results in a shadow price of load factor ($PF_{f,i,n}$) with units \$/MW$_e \cdot$ h^2. The value of this cost can be found by multiplying by the time of one load segment – $PF_{f,i,n} \times t_{seg}$. Section 3.2 provides further details on the significance of the load factor.

3. Generating firms may also be subject to a carbon emissions cap, which limits the total amount of carbon emissions across all load segments for all generators of a given firm and results in a shadow price on firm carbon emissions or carbon price (PE_f) with units \$/t $CO_2 \cdot$ h. The value of this cost per MWh$_e$ generated can be found by multiplying by the generator carbon intensity ($carb_i$) and the time of one load segment – $PE_f \times carb_i \times t_{seg}$. When the carbon market is modelled with a carbon tax, the term $PE_f \times t_{seg}$ takes on a fixed value for all generators equivalent to the value of the tax with units \$/t CO_2.

Given these limitations, and a marginal cost of generation mc_i, generating firms will exhibit profit-maximising behaviour in each load segment according to the following equations:

$$\max_{X_{f,i,n,s}} \pi_{f,s} = \sum_{i,n \in f} (P_{n,s} - mc_i) X_{f,i,n,s}$$

such that:

$$gcap_i \geq X_{f,i,n,s} \qquad \perp PG_{f,i,n,s} \tag{2.8}$$

$$fcap_i \geq \sum_s X_{f,i,n,s} \cdot t_{seg} \qquad \perp PF_{f,i,n} \tag{2.9}$$

$$ecap_f \geq \sum_{i,n,s \in f} carb_i \cdot X_{f,i,n,s} \cdot t_{seg} \qquad \perp PE_f \tag{2.10}$$

Forming a Lagrange optimisation problem of the generator conditions gives the following, where $PG_{f,i,n,s}$, $PF_{f,i,n}$ and PE_f are the Lagrange multipliers for each of the generator constraints:

[4] This is clearly not the case in practice. However, generating firms are reasonably aware of future market outcomes given their knowledge of historical information, spot trends and explanatory factors such as weather forecasts. Therefore, this is a valid modelling assumption.

$$\begin{aligned}\mathcal{L}_{f,i,n,s} = &\sum_{i,n\in f} (P_{n,s} - mc_i)X_{f,i,n,s} \\ &+ PG_{f,i,n,s}(gcap_i - X_{f,i,n,s}) \\ &+ PF_{f,i,n}\left(fcap_i - \sum_{s} X_{f,i,n,s} \cdot t_{seg}\right) \\ &+ PE_f\left(ecap_f - \sum_{i,n,s\in f} carb_i \cdot X_{f,i,n,s} \cdot t_{seg}\right)\end{aligned}$$

Differentiating the Lagrangian of the generator conditions with respect to $X_{f,i,n,s}$ achieves the first order conditions and the zero-profit equation for an individual generator i:

$$\begin{aligned}mc_i + PG_{f,i,n,s} + PF_{f,i,n} \cdot t_{seg} + PE_f \cdot carb_i \cdot t_{seg} \\ \geq P_{hub,s} + PT_{n,s} \qquad \perp X_{f,i,n,s}\end{aligned} \tag{2.11}$$

where $P_{n,s} = P_{hub,s} + PT_{n,s}$.[5]

Figure 2.6 indicates the significance of the zero-profit condition for generators. For simplicity, assume that any given generator i is constrained only by its nominal capacity (with capacity rent PG_i), generates at marginal cost mc_i and that there is a single equilibrium price P^* in a perfectly competitive market. Under these circumstance, Equation 2.11 becomes:

$$mc_i + PG_i \geq P^* \qquad \perp X_i$$

In Figure 2.6, the generator with the lowest marginal cost (mc_1) produces X_1 up to its nominal capacity limit, at which point it is capacity-constrained. With additional capacity, it would have been profitable for this generator to produce more, considering the market price of $P^* > mc_1$. Therefore, this constraint results in a capacity rent PG_1 that is equal to the difference in the marginal cost and the market price and represents the forgone benefit to the generator of having an additional unit of capacity. Therefore, the sum of marginal cost and capacity rent equals the market price, forming the zero-profit condition for generators. Each subsequent generator with higher marginal cost has a capacity rent of reduced magnitude. The marginal generator ($i = 5$) has a capacity rent of 0 as it produces at or below its nominal capacity. In a perfectly competitive market, the marginal cost of this generator sets the market clearing price. In the full-model zero-profit condition (Equation 2.11), all constraining factors contribute to this difference in marginal cost and market clearing price making up the zero-profit condition for generators.

In the case of Cournot strategic behaviour by generators, the right-hand side of Equation 2.11 becomes:

[5] It should be noted that, in all pricing scenarios, generators will be exposed to a location-specific price determined by $P_{n,s} = P_{hub,s} + PT_{n,s}$.

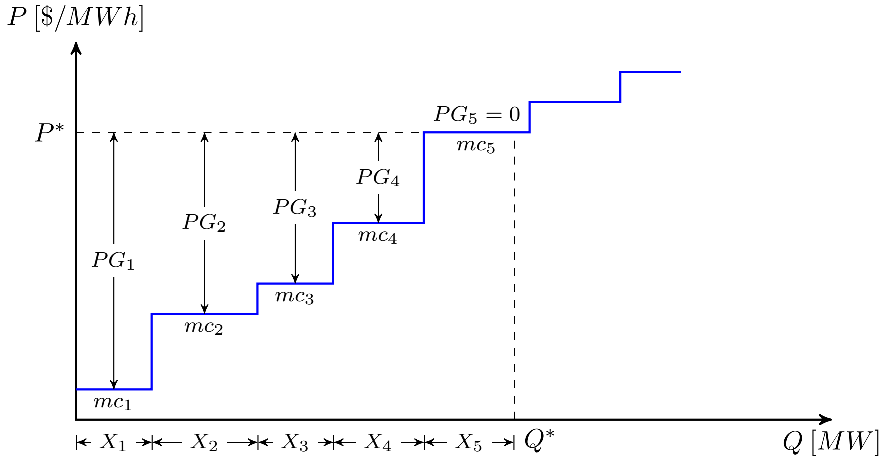


Figure 2.6: Capacity Rent for Generators

$$(P_{hub,s} + PT_{n,s})\left(1 - \frac{\Omega_{f,s}}{|\epsilon|}\right)$$

with the determination of market share given by:

$$\Omega_{f,s} = \frac{\sum_{i,n\in f} X_{f,i,n,s}}{\sum_n Q_{n,s}} \qquad \perp \Omega_{f,s} \tag{2.12}$$

The inclusion of market share in the zero-profit condition under a Cournot Oligopoly framework is a result of the fact that generating firms are no longer price takers, but instead view the market clearing price as a function of total output such that $P_{n,s} = P_{n,s}(Q_{tot})$. Appendix B.1.2 provides further details on the economic theory outlining this. Furthermore, Sections 2.3.2 and 2.6.2 discuss in detail the mechanisms by which generating firms profit from a Cournot Oligopoly framework.

2.7 Model Functionality

This economic model is better suited to static short term analysis of current or hypothetical network configurations. Long term investment decisions and dynamic changes to the network are not components of this model. In other words, generators cannot expand or relocate capacity, or substitute to different generation technologies that may offer competitive advantages in light of policy changes. Similarly, transmission capacity cannot be expanded or non-existing connections made to alleviate congestion. However, the model can analyse present-day market outcomes to hypothetical network configurations or benchmark loads and prices. For instance, questions that can be analysed using this model include, but are not limited to:

1. How will the current network configuration cope with an increase in benchmark demand? Is new generation or transmission capacity required to

meet growing consumer demands? Where should these new assets be located and what characteristics do they have?

2. How does changing the pricing mechanism affect the market? What are the consequences for net social welfare, consumer and generating firm behaviour, real power flows and transmission congestion?

3. How does the allocation of nodes into zones affect the market? Can the major benefits of a LMP mechanism be realised by the correct allocation of nodes to zones?

4. What is the effect of assuming that generating firms act strategically? Does LMP provide more opportunities for generating firms to exert market power? To what extent is the notion of market power a function of how the market is disaggregated into its LMP nodes or zones? In other words, does a high degree of disaggregation empower generating firms to act strategically?

5. What is the effect of a carbon price on the behaviour of participants and market outcomes? How does this change if it is applied as an emissions cap or a fixed carbon tax? What is the price of carbon for a given reduction in firm carbon emissions in an emissions cap scenario? What reduction in firm and total carbon emissions is observed for a carbon tax of a given value?

6. To what extent is the network, in its current state, reasonably capable of reducing carbon emissions without a carbon price of crippling magnitude? How does the addition of cleaner generation technologies into the network mitigate this?

7. Do small-scale distributed generators located in capacity-constrained areas alleviate transmission congestion? For what transmission congestion fee does installing distributed generation become an attractive option? How does this change when considering the benefits of secondary markets for distributed generators such as heat?

8. Given an expected increase in demand, what is an appropriate target capacity of distributed generation to meet set congestion mitigation objectives?

Chapter 3

Strategies for Transmission Network Characterisation

A tool has been developed for characterising a transmission network that uses specific exogenous inputs largely available in the public domain. This tool defines, calculates and exports all necessary sets and parameters to the model for analysis, and also provides network visualisation diagrams. The tool is divided into three main attributes of a transmission network: loads, generation and transmission. A complementing tool for aggregating detailed load segment and corresponding price data into a representative load-duration set was also developed, which is useful for significantly reducing model computing time while still retaining the key features of the consumer load profile.

This chapter describes the features of both of these tools as they apply to the NSW electricity transmission network. Application of these tool to other networks may require modifications specific to the network but, where possible, they were designed to be applied generically.

Appendix A provides a list of all sets, parameters, variables and relevant data. The GAMS code specific to the characterisation of the NSW transmission network can be found in Appendix C.2, while the GAMS code for the load-duration aggregation tool can be found in Appendix C.3.

3.1 Load Characterisation

Historical load data for the NSW region is readily available for public download from the website of the Australian Energy Market Operator (AEMO) (accessed April 18, 2011). These data consist of the aggregated NSW regional load in MWh_e for each half-hour billing period in any given year with the corresponding market price in AU\$/MWh_e. In its published state, this data set consists of 17,520 load segments, which makes it too extensive for use in the model. When analysing across a number of network scenarios, the necessary computing time to solve the model is inappropriate. Consequently, the published load data were aggregated into 20 representative load-duration segments of equal length, plus the annual 'peak' load segment found in the data set using a load-duration aggregation tool. This aggregated data set was computed by minimising the least squares residual between the aggregated and original data set and retains the main trends of the original data set with appropriate resolution. A similar approach was taken to aggregate the corresponding price data. Importantly, the use of aggregated load-duration segments removes the possibility of modelling successive temporal characteristics of a network such as generator ramp rates. Figure 3.1 compares the original and aggregated load duration curves for 2010.

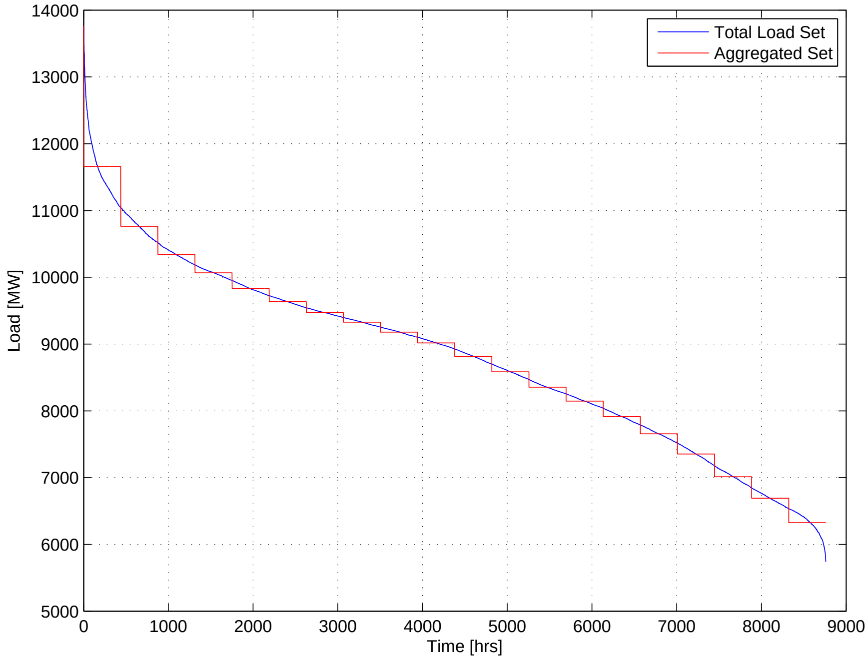


Figure 3.1: Load Duration Curve with Aggregated Set

The available data are not separated into the load for each of the individual nodes in the model. As such, it was necessary to assume that demand at a node is proportional to the fraction of the total population at that node. This assumption is not ideal because it does not account for the regional difference in load profiles that will exist on account of the differences in industries and services across NSW. Nevertheless, for the illustrative purposes of this model, it is a reasonable assumption to allocate the complete regional load data to each node. For specific population data, the 'Statistical Subdivision' of the '2006 Australian Census of Population and Housing' was used (accessed May 2, 2011). The consumer price elasticity of demand was assumed to be constant across load segments and nodes. This value of -0.4 was taken from an econometric study explaining demand profiles in the state of South Australia (Fan and Hyndman, 2011).

3.2 Generation Characterisation

The majority of the data used to define the properties of each generator in the NSW electricity network were taken from published data following the 2010 National Transmission Network Development Plan (NTNDP). This was a comprehensive modelling-based study that assessed the current and future states of the national transmission network given certain policy and macro-economic conditions (Australian Energy Market Operator (AEMO), 2010).

The key generator inputs to the model are the short-run marginal cost of generation, maximum nominal capacity, load factor, carbon emissions and firm ownership. The generator maximum nominal capacity parameter data are input to the model directly from the NTNDP source.

The definitions for the calculation of the short-run marginal cost (mc_i) and the total emissions of a generator i were taken from a report written by ACIL Tasman, an Australian economic consultant that was commissioned by the AEMO to determine the bidding behaviour of generating agents participating in the National Electricity Market (NEM) (ACIL Tasman, 2009). The short-run marginal cost calculation assumes that the generation capacity of a plant remains fixed over the period of analysis and is calculated as follows:

$$mc_i = \eta_{i,fuel} \times pf_i + vc_i \tag{3.1}$$

where pf_i is the fuel cost for a generator in \$/GJ fuel, vc_i is the variable operation and maintenance cost in \$/MWh$_e$ and $\eta_{i,fuel:}$ is the heat rate:

$$\eta_{i,fuel} = \eta_{i,\%} \times 3.6 \, \frac{MWh_e}{GJ\ fuel} \tag{3.2}$$

With the short-run marginal cost of generation for each generator in the network known, a marginal cost curve can be drawn that indicates the theoretical generation mix of the network for a given load under conditions of perfect competition and no transmission congestion. This can be seen in Figure 3.2, where the red line indicates the scenario that includes all six distributed generators in the City of Sydney (SDGs).

The total emissions for a generator is made up of the combustion emissions resulting from the fuel conversion process of the thermal power plant and fugitive emissions resulting from the mining, processing and transportation of the fuel to the point of use:

$$carb_i = \eta_{i,fuel} \times (em_{com,i} + em_{fug,i}) \times \frac{tonne}{1000\ kg} \tag{3.3}$$

where $em_{com,i}$ and $em_{fug,i}$ are both provided in kg CO_2/GJ fuel.

The load factor for each generator is used to calculate the total permissible energy output over all of the analysed load segments. Therefore, this parameter requires generators to consider a temporal constraint when deciding to dispatch. For generators with a low marginal cost (like the hydro-generators), this constraint prevents full dispatch across all load segments. It is intended to capture realistic operating considerations such as scheduled maintenance shutdown periods and acknowledgement of limited and competing demands on water resources in the case of the hydro-generators. The total output across all load segments using the load factor is as follows:

$$\sum_s X_{i,s} = fcap_i \times gcap_i \times total\ analysis\ time \tag{3.4}$$

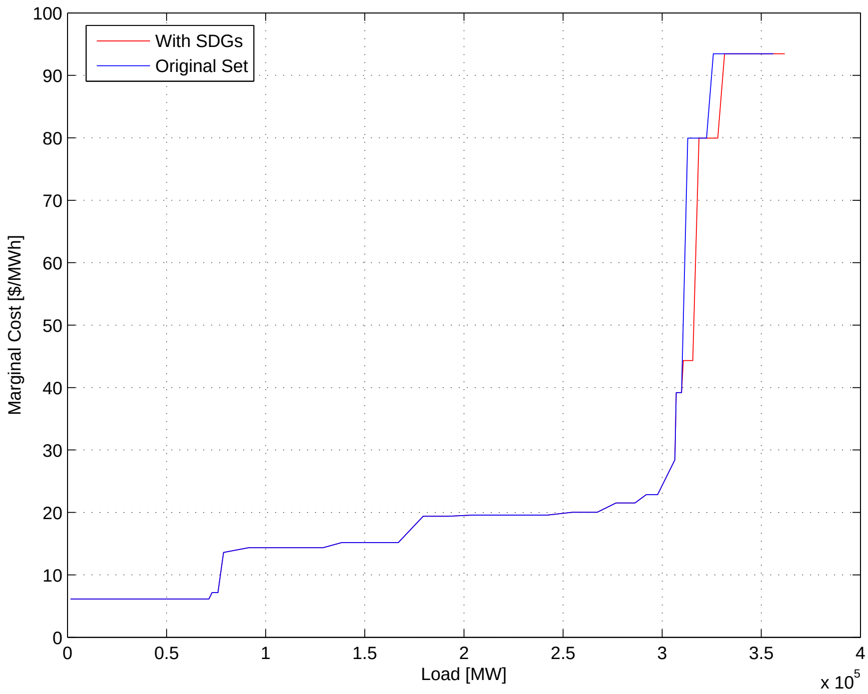


Figure 3.2: Short-Run Marginal Cost Curve

In this model, the effect of the load factor will be distributed across all load segments according to the least-cost dispatch outcome. In reality, however, periods such as scheduled maintenance will occur sequentially, such that the consequence of the load factor is realised in successive load segments. This could not be captured in this model considering the use of aggregated load-duration data.

The firm ownership of generators is an important property for modelling the strategic behaviour of firms under the Cournot modelling scenarios. It is also important from the point of view of carbon emissions. The model allows an effective price on carbon in two ways: as an exogenous carbon tax or by defining an annual limit on the carbon emissions permitted by a single firm. This second method for pricing carbon requires firms to make temporal generation decisions across all load segments and their entire generation profile. In doing so, it establishes a shadow cost of carbon emissions for a firm, the average of which is the effective market carbon price. Benchmark emissions data for each firm were established by observing firm emissions from a single-model run that represents Business-As-Usual (BAU) conditions if 300 MW_e of distributed generation capacity was available in the City of Sydney. These conditions consisted of perfect competition, zonal pricing according to the retail zones, the price of carbon fixed at zero and 6 distributed generators in the City of Sydney. These conditions are believed to best represent the current power market in NSW with the inclusion of DGs in the City of Sydney to determine their emissions benchmark cap. Table 3.1 shows the benchmark emissions cap for each firm. Different model runs examine the effect of capping firm emissions at up to 65 percent of these benchmark values.

Table 3.1: Benchmark Annual Carbon Emissions by Firm

Firm	Output [MWh_e]	Emissions [t CO_2/yr]
Macquarie Generation	35880960	36930771
Redbank Project	1169460	1418200
Eraring Energy	20918880	20785538
Delta Electricity	20720703	20221643
Marubeni Australia	77172	44383
TRUenergy	360622	170070
Origin Energy	25	18
Snowy Hydro	3085289	–
Sydney DG	131543	62595
Totals	82344653	79633218

The following are additional features of generators that have not been included in this model but are also important characteristics with real economic consequences.

Minimum Generation Limits
Most large thermal generators are physically bound by a minimum generation limit in addition to an upper nominal capacity. With such a constraint, generators still have the option to not dispatch in a load segment. In other words, the minimum generation limit represents the minimum level of output from a generator that chooses to dispatch in a given load segment; it does not represent a minimum bound on the dispatch decision variable. A minimum generation limit will have an associated shadow cost that comes into effect when a generator finds it profitable to dispatch but at a level below their minimum generation limit. This constraint forces the generator to either not dispatch or to dispatch unprofitably at levels above what is profitable up to the minimum generation limit.

Reserve Capacity
In some markets, generators can be mandated to hold a proportion of their capacity in reserve so that this capacity can be dispatched by the system operator in periods of unexpectedly high loads. This results in a shadow cost of 'spinning reserve' that is similar to the shadow cost of capacity (capacity rent). The system operator can compensate for this cost in the form of a capacity payment or through the potential for generators to profit in a secondary market for load-balancing outside of their dispatch commitments. Capacity payments and secondary load-balancing markets are not features of this model. Consequently, the inclusion of a reserve capacity constraint will have the same result as reducing the nominal capacity of generators.

Ramp-up and Ramp-down Rates
These physical properties of generators result in an additional shadow

cost, where an opportunity to dispatch and profit may be lost due to the generator being physically incapable of increasing output at a fast enough rate. Conversely, a generator may be forced to dispatch electricity that it would not otherwise have on account of a limited ramp-down rate. Like reserve capacity, there is value to the system operator in being able to call on generators to immediately increase or decrease its output for system balancing purposes, which can be reflected in the aforementioned secondary market or in capacity payments to generators. Large thermal generators, such as coal and nuclear, typically have slow ramp rates, which means that reserve capacity cannot be readily dispatched or recalled at short notice. Gas turbines and hydroelectric plants have fast ramp rates with greater 'load-following' potential. The use of ramp rates requires the model to be solved in successive load segments. As previously discussed, the load data have been aggregated into load-duration segments, removing the possibility of including this property of generators.

3.2.1 Hydro-Generators

Hydro-generators have special properties that require different treatment within an economic model. Hydro-generators typically have very low marginal costs, which means that hydro-electricity will be the first to be dispatched when clearing the market. However, hydro-generators are constrained by a water resource mass balance. Specifically, water must be stored in a dam or reservoir and must be available for release and the subsequent generation of electricity. This resource is finite and will often have competing demands for municipal water supply or environmental releases, for example. Therefore, the management of this resource is not simply a case of dispatching electricity at all times. This consideration has largely been captured in the model through the capacity factor, which is typically low for all the hydro-generators. Alternatively, a known operating schedule could have been used similar to that adopted by the University of Queensland in a model developed with the Australian Commonwealth Scientific and Industrial Research Organisation (CSIRO) (University of Queensland, 2009). One disadvantage of this approach is that it does not allow the hydro-generators to dispatch according to the market. A fixed schedule will not allow the hydro-generators to best utilise their competitive advantages of low marginal cost and high ramp rates.

Another feature of hydro-generators is that their decision variable to dispatch should be binary (on/off), where 'on' commits to a full capacity dispatch and 'off' indicates zero generation. In reality, the total power output will be a function of the water level in the reservoir. A more complicated model would take stock of the water resource, accounting for rainfall and competing demands, so that the operation of hydro-generators better reflects the whole system considerations. This level of complexity is beyond the scope of this model.

In this model, all hydro-generators use dammed water resources with no potential for pumped storage. Other hydro-generators have the potential to store energy through a pumped storage scheme, which must be accounted for in the model with an additional decision variable for these generators to store (consume) 'electricity'. The load factor for pumped storage hydro-generators will need to be a function of the consumption and dispatch decision variables. Other types of hydro-generators, such as 'run-of-river' generators, have different properties, such as speed and volumetric flow, that will be accounted for in more complex models.

Interestingly, the fact that hydro-generators typically have very fast ramp-up and ramp-down rates makes them particularly valuable to system operators when balancing the market. Countries that have high hydro penetration in the generation profile, such as Norway (~98 percent) (International Energy Agency (IEA), accessed May 18, 2011), are able to profit from their ability to follow loads very closely. With such a flexible generation profile, Norway can readily absorb fluctuations in other power markets to which they are linked, such as Germany, the Netherlands, Denmark, Sweden and Finland.

3.3 Transmission Characterisation

The Transmission Network Characterisation Tool that was developed allows for the topology of a transmission network to be specified by indicating the latitude and longitude of nodes and their circuit connections. Individual circuits connecting nodes are converted into a single line-equivalent transmission line, where each circuit has a specified nominal voltage in kV and capacity in MW_e. Based on the exact location of the nodes, the 'Great Circle Distance' of connections is calculated using a modified version of a programme found in the GAMS library (Brooke, 1988). Based on this distance and the nominal voltage, the impedance of each circuit is determined using the information contained within Table 3.2 and Table 3.3 (Kundur, 1994).

Table 3.2: Typical Impedance Values for Overhead Lines

Nominal Voltage [kV]	230	345	500	765
Resistance [Ω/km]	0.050	0.037	0.028	0.012
Reactance [Ω/km]	0.407	0.306	0.271	0.274
Admittance [μS/km]	2.764	3.765	4.333	4.148

Table 3.3: Typical Impedance Values for Cables

Nominal Voltage [kV]	115	230	500
Resistance [Ω/km]	0.059	0.028	0.013
Reactance [Ω/km]	0.252	0.282	0.205
Admittance [μS/km]	192.0	204.7	80.4

As the following sections show, the only parameters necessary to characterise the transmission lines in the network are the reactance and capacity. The capacity of a single equivalent transmission line is simply the sum of the capacity of each individual circuit. Based on the values contained in Tables 3.2 and 3.3, the reactance of each circuit can be calculated by multiplying the reactance in Ω/km with the circuit distance in km. Following this, conversion to per unit is necessary for the computation of further parameters. This calculation is shown below, where a reference line and circuit must be chosen. For this tool, the line and circuit with the highest reactance was taken as the reference such that all values in per unit are less than or equal to 1.

$$Value\ in\ p.u. = \frac{Actual\ Value}{Reference\ Value} \tag{3.5}$$

such that:

$$x_{c,\,p.u.} = \frac{x_{c,\,\Omega}}{x_{c,\,\Omega,\,ref}} \tag{3.6}$$

With known individual circuit reactances, the total capacitive reactance of an equivalent single transmission line x_{line} can be calculated as follows:

$$x_{line} = \frac{1}{\sum_c \frac{1}{x_c}} \tag{3.7}$$

where c is an individual circuit in a parallel connection and x_c is its reactance in ohms (Ω).

With knowledge of the reactance of the single line equivalent transmission lines, parameters that determine real power flows within the network given a generation and load profile can be calculated using the power flow equations.

3.3.1 Power Flow Equations

In addition to market considerations, an electricity transmission network is subject to physical laws that govern the injection, withdrawal and flow of power. One of the challenges of power system analysis is to define the complete state of a transmission network so that it is known not only where power is generated and consumed, but how it flows from one location to another. The physical laws that govern this flow of power have economic consequences. Therefore, in addition to market considerations, the inclusion of power systems principles in an economic model is crucial in order to correctly assess the value of physical network constraints.

To this end, the state of an electric power system can be fully defined with knowledge of the voltage magnitude ($|V_i|$) and phase angle of each node[1] (δ_i) in the network. This is done by way of the 'Power Flow Equations', which describe the conservation of complex power (S_i) in a network. Specifically, the sum of complex power at a node must always be equal to zero. The power flow equations expressed in terms of their real and imaginary components, where $S_i = P_i + jQ_i$ are as follows (von Meier, 2006):

Conservation of real power at node i:

$$P_i = \sum_j |V_i||V_j|(G_{ij}\cos\theta_{ij} + B_{ij}\sin\theta_{ij}) \tag{3.8}$$

[1]The term 'bus' is normally used in power systems literature. For consistency with the economic model, the term 'node' will be adopted throughout this thesis.

Conservation of reactive power at node i:

$$Q_i = \sum_j |V_i||V_j|(G_{ij} \sin\theta_{ij} - B_{ij} \cos\theta_{ij}) \tag{3.9}$$

where $\theta_{ij} = \delta_i - \delta_j$.[2]

In the above equations, the unknown variables are the voltage magnitudes and the node phase angles. The admittance parameters (G_{ij} and B_{ij}) relate to the physical characteristics of the transmission lines; hence they are exogenously defined. The complex power terms (P_i and Q_i) are controlled variables determined by the generation and load profile of a node. Therefore, the power flow equations present a non-linear system of equations for V_i and θ_i that must be solved in order to determine the physical flow of power over each transmission line in the network.

3.3.2 DC Linear Power Flow Assumptions

There is no closed-form solution to the power flow equations. Therefore, solutions to this non-linear system of equations require advanced numerical techniques, such as the Newton-Raphson method or the Gauss-Seidel method. For non-trivially sized networks, significant computational power is required to find a solution to this problem. In addition, for the purpose of economic modelling, where the intent is to illustrate market concepts within physical laws, the full power flow equations contain excessive complexity and information that is not relevant to the final analysis. Therefore, a set of simplifying assumptions are used, commonly referred to as the 'DC Linear Power Flow Assumptions'. They enable a closed form solution to a linear system of equations, while still retaining the physical laws governing the network in sufficient detail. These assumptions are as follows (Purchala et al., 2005):

1. Line resistance is negligible such that $R_{ij} \ll X_{ij}$
2. There is a flat voltage profile such that all node voltages are close to 1 p.u.
3. Phase angle differences across lines (between nodes) are small.

The first assumption allows the definition of all real components of complex admittance to be equal to zero. That is, the conductance G_{ij} term drops out where $G_{ij} = \frac{R_{ij}}{R_{ij}^2 + X_{ij}^2}$. The second assumption further reduces the equations by removing both voltage terms as they both equate to 1. The third assumption allows for the approximation that $\sin\theta_{ij} \approx \theta_{ij}$ and $\cos\theta_{ij} \approx 1$. Finally, considering that our point of interest is real power flow in a DC system, reactive power can be ignored. Therefore, with the application of the DC linear power flow assumptions, the power flow equations reduce to the following:

$$P_i = \sum_j P_{ij} = \sum_j B_{ij}\theta_{ij} \tag{3.10}$$

[2] Appendix B.2 provides a simplified derivation of the Power Flow Equations.

This equation can also be expressed in matrix notation where $\mathbf{B_X}$ is the susceptance matrix:

$$\begin{bmatrix} P_1 \\ \vdots \\ P_n \end{bmatrix} = \begin{bmatrix} & \\ \mathbf{B_X} & \\ & \end{bmatrix} \begin{bmatrix} \theta_1 \\ \vdots \\ \theta_n \end{bmatrix} \tag{3.11}$$

$$\mathbf{B_X} = \begin{bmatrix} B_{11} & \dots & B_{1m} \\ \vdots & B_{ij} & \vdots \\ B_{n1} & \dots & B_{nm} \end{bmatrix}$$

For the diagonal elements of the susceptance matrix, the following relation is used:

$$B_{ii} = b_{i1} + \ldots + b_{im} = \sum_j b_{ij}$$

Similarly, for the off-diagonal elements, the following is used:

$$B_{ij} = -b_{ij} = \frac{1}{x_{ij}}$$

In combination with the active power generated ($P_{G,i}$) and consumed ($P_{L,i}$) at each node, the total energy balance for the system is:

$$\sum_i (P_{G,i} - P_{L,i} - P_i) = 0 \tag{3.12}$$

With this linear system of equations for θ_{ij}, the state of the network can be readily computed and the actual power flow between two nodes determined for exogenously defined generation and load profiles.

3.3.3 Power Transfer Distribution Factors

The DC linear power flow equations can also be used to derive useful parameters that are used frequently in economic models of power systems. One such set of parameters are 'Power Transfer Distribution Factors' (PTDFs). PTDFs describe the sensitivity of any transmission line in a transmission network to a power transaction. A power transaction can be thought of as an injection of power by a generator at node m in the network and the subsequent withdrawal of this power at node n. The PTDF value indicates the fraction of power flowing over any line l as a result of this transaction. The use of PTDFs in economic models is convenient as they retain all information contained within the DC linear power flow equation but present this information in a format that lends itself to a more readily understandable physical interpretation.

To derive the set of PTDF values for a network, it is first necessary to compute the reactance matrix by inverting the susceptance matrix. However, the susceptance matrix is singular, which means that a matrix inversion will be undefined. As such, a reference or 'slack' node should be nominated by declaring the phase angle to be zero at this node, thereby eliminating its row and column from the susceptance matrix.[3] Inverting the non-singular susceptance matrix gives the following, where $\mathbf{X}$ is the reactance matrix:

$$\begin{bmatrix} \theta_1 \\ \vdots \\ \theta_{n-1} \end{bmatrix} = \begin{bmatrix} \\ \mathbf{X} \\ \\ \end{bmatrix} \begin{bmatrix} P_1 \\ \vdots \\ P_{n-1} \end{bmatrix} \tag{3.13}$$

Using the reactance matrix, the PTDF matrix is computed as follows, where a transmission line l connects node i to node j, upper-case X_{im} values are elements of the reactance matrix and lower-case x_{ij} values are the original line reactances (Christie et al., 2000):

$$ptdf_{i,j,m,n} = \frac{(X_{im} - X_{jm}) - (X_{in} - X_{jn})}{x_{ij}} \tag{3.14}$$

For the economic model, the set of PTDF values used is only for transactions following a marginal injection of power at the slack node. That is, the dimensionality of the PTDF matrix is reduced such that $ptdf_{i,j,m,n}$ becomes $ptdf_{l,n}$, where m is the slack node and l is the transmission line connecting node i with node j. Hence, a PTDF matrix has the following features:

- A PTDF value is between -1 and 1 such that: $-1 \leq ptdf_{l,n} \leq 1$
- The sum of the PTDF values of all lines *out of* a node is equal to -1 for a given transaction
- The sum of the PTDF values of all lines *into* a node is equal to 1 for a given transaction.

It should also be highlighted that PTDFs are calculated using only physical properties of the transmission lines making up a network. Specifically, knowledge of the reactance[4] of each transmission line is the only parameter necessary to compute a PTDF matrix. As such, PTDFs are constant across load segments and not influenced by changes in generating capacity or loads at a node in the network. Importantly, PTDFs are also independent of the capacity of a transmission line. These characteristics allow for a one-off calculation of the PTDF matrix for a given network topology and the subsequent analysis of the network when it is subjected to changes in generation, load or transmission profiles or market adjustments. Only in the event that the network topology is changed or the nominal voltage of an existing line altered will the PTDF matrix need to be recalculated. In this way, PTDFs provide a convenient way to account for the power flow laws when creating economic models of electricity transmission networks.

[3] The choice of slack node is not important from a physical power flow point of view.

[4] Strictly speaking, it is the impedance of a transmission line that is constant and dependent on physical characteristics of the transmission line (material composition, diameter, length and to a lesser extent temperature). As noted above, the impedance reduces to simply the reactance (the complex component of impedance) with the 'DC Linear Power Flow Assumptions'.

Illustrative Example of PTDFs

Figure 3.3 illustrates the use of PTDFs, using the example of the NSW transmission network, where 100 MW_e of energy is injected at $n7$ and withdrawn at $n10$. The proportion of flow along each transmission line as a result of this transaction is evident, where a negative number simply indicates the direction of flow.[5] Of note is the value of 0 for the flow along all transmission lines into nodes that are external to the possibilities of the transaction (GC, $SWQLD$, $n1$, $n2$, $n3$, $n16$ & VIC).

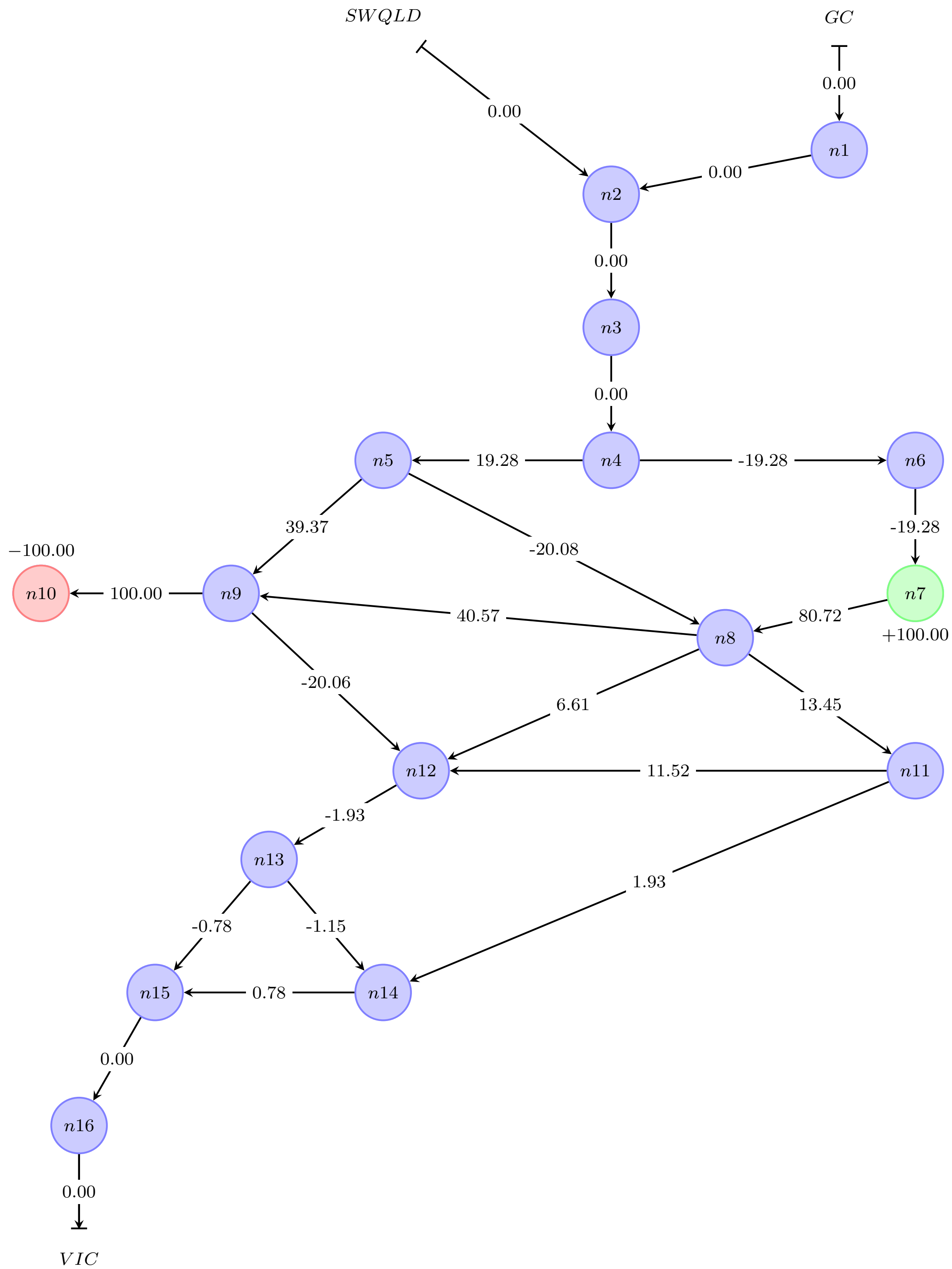
3.3.4 Conservation of Energy

A key outcome from the power flow equations is the conservation of energy. Specifically, all electricity must be consumed at the same instant it is generated; this means that electricity cannot be stored in the transmission network. In other systems, electricity can be stored chemically (by way of batteries) or as potential energy (by way of a pumped hydro system). From a physical and modelling point of view, however, these units operate as a load when storing energy and as a generator when injecting energy. In the case of the NSW transmission network, there are no batteries or pumped storage units. The model can be modified to include storage systems, in which case examining the model over meaningful and sequential load segments is important to properly understand their operating behaviour and interaction with other network components.

Transmission lines normally have energy losses that are a function of the current and the resistance (real component of impedance) of a line. However, given the assumption that line resistance is negligible ($R_{ij} \ll X_{ij}$), it is not appropriate to account for these losses in this model. If resistive losses were to be included in the model, this would be another means (in addition to loads) by which energy could leave the system, which should be reflected in the overall energy balance.

[5] All transmission line directions are defined as originating from the node of lower label number. In the case of the boundary nodes, the positive direction is defined as being *out of* GC and SWQLD and *into* VIC.

Figure 3.3: Illustrative Example of PTDFs



Chapter 4

Model Simulations

Model simulations are able to recreate and reveal many interesting aspects of a liberalised power market. The observations of these model simulations relate directly to the NSW power market, but should be done with knowledge of the assumptions used to characterise the network. In the simulations described here, the highly complex network of NSW was aggregated into 16 nodes and 21 indicative transmission lines. In addition, total network demand was disaggregated into nodal demands according to population fraction only. Details of these assumptions can be found in Section 1.4, Chapter 3 and Appendix A.

A further assumption relates to the transmission capacity of lines connected to the node representing the City of Sydney ($n8$). In order to observe transmission congestion, the nominal capacity of each of these lines was reduced to 45 percent of their determined capacity for all model simulations. This allowed for more meaningful observations with respect to the pricing mechanism and the addition of distributed generators in Sydney. This assumption is not totally invalid, as it can be interpreted as an increase in demand in the region represented by Sydney without additional investment in transmission capacity.

Figures 4.1 and 4.2 indicate the difference between the benchmark data used to calibrate the model and the equivalent modelled output for both the total network demand and the average network price. These figures reveal that the modelled outputs closely match the magnitude and trends of the benchmark data sets. Total network demand and average network price were the only two data sets publicly available to calibrate the model.

This section describes the observations of model simulations designed to examine one technology and two policy options for the NSW power market. Specifically, these options are as follows:

1. A change in the pricing mechanism from zonal pricing to Locational Marginal Pricing (LMP)

2. The implementation of a carbon price by way of a carbon tax or an emissions cap on generating firms

3. The addition of distributed generators in the City of Sydney.

This section also examines the effects of assuming that generating firms act as Cournot oligopolists and discusses why the conclusions of these simulations

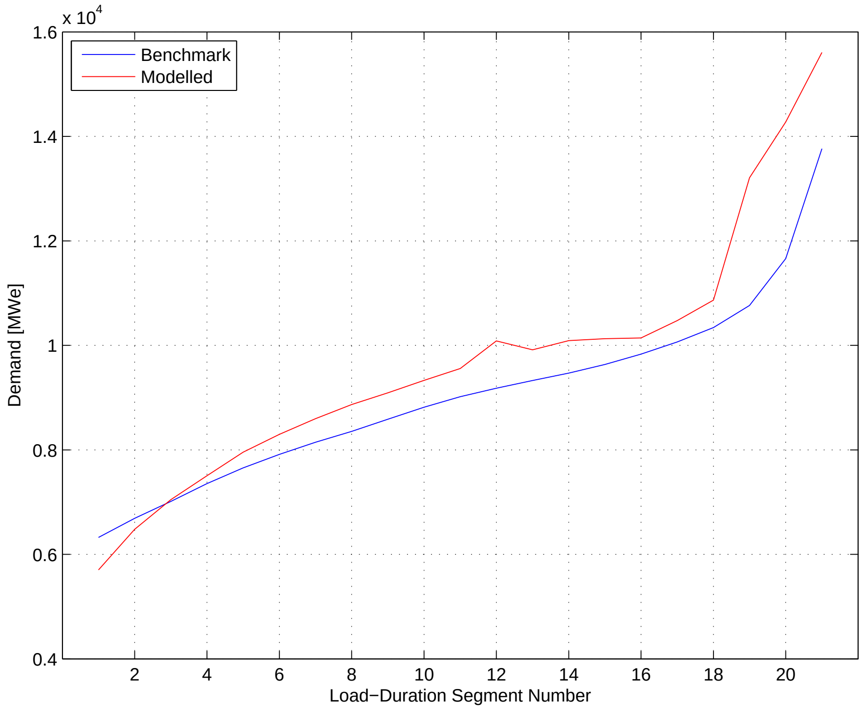


Figure 4.1: Benchmark and Modelled Demand

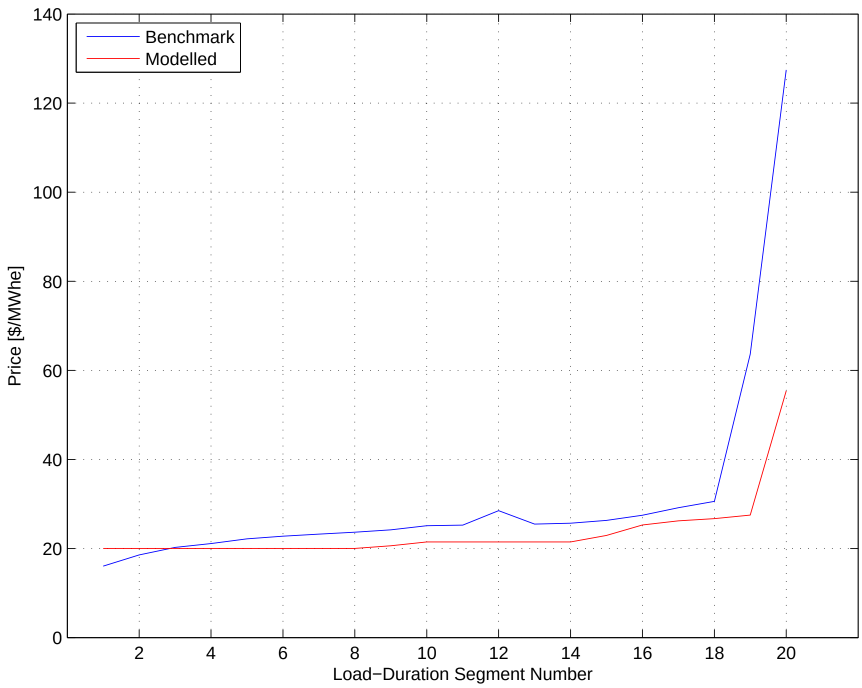


Figure 4.2: Benchmark and Modelled Price

are important for policy makers. All other model simulations assume a perfectly competitive framework.

4.1 Pricing Mechanism

The pricing mechanism that a power market employs has significant implications for the efficient deployment of generation and transmission services. In short, electricity is a homogeneous product delivered at a time and place in a complex network. The ease with which this delivery takes place is depends on occurrences in other parts of this network and the time at which delivery takes place. This model assumes a completely liberalised approach with respect to the temporal component of price. All participants are exposed to a dynamic price, which can differ across load-duration segments. This is in contrast to most functioning power markets, in which domestic consumers pay a regulated fixed single or dual-tariff price. However, the use of dynamic pricing for all participants results in the most efficient market outcome with respect to time. This allows spatial components of price to be analysed without temporal distortion. Furthermore, there is a general industry trend toward dynamic pricing meters as this technology becomes more accessible.

With respect to the spatial component of price, model simulations examined three increasingly liberalised pricing mechanisms, as follows:

1. A single network price in which all consumers in the network pay the same price, irrespective of location. This price is the demand-weighted average of the locational marginal price.

2. Zonal pricing in which all consumers within a predetermined zone of the network pay the same price. This price is the demand-weighted average of the locational marginal price of nodes within the predefined zone. It is the BAU pricing mechanism for the NSW power market, as discussed in Section 1.4.

3. Locational Marginal Pricing (LMP) in which consumers in the network pay a different price depending on their location.

Note that the pricing mechanism only changes on the consumer side. In other words, generators in all pricing mechanism scenarios are exposed to the location-dependent price as in LMP. Furthermore, it is only in times of transmission congestion that there is any difference between the three pricing mechanisms. That is, with zero transmission congestion anywhere in the network, the price under the LMP scenario at every node is identical – equivalent to a single network price.

Figure 4.3 presents key welfare indicators for the entire network relative to the single network price scenario. The first point to note from this figure is that the total network demand does not change as the pricing mechanism becomes more liberalised. This is because generators are always exposed to LMP, so the market clearance quantity does not adjust. Instead, an increasingly liberalised pricing mechanism provides additional opportunities for consumers to elicit a demand response at individual nodes. This is reflected in the increase in consumer surplus across the three scenarios.

Given the increasingly location-dependent nature of the pricing mechanisms, the price signals in any given area become more indicative of the cost of transmission services to deliver electricity to that location. As such, consumers respond by consuming less in capacity constrained areas and more in uncongested areas. This results in a more efficient allocation of transmission resources and the corresponding decrease in the fee charged by the system operator. Likewise, the Dead Weight Loss (DWL) of the entire network is also reduced as the pricing mechanism becomes increasingly liberalised. In the case of LMP, the DWL represents only the inability of the network to satisfy all customers in times of transmission constraints due to its physical limitations. From an economic market clearance point of view, the LMP mechanism perfectly allocates available transmission and generation resources, with zero DWL attributable to market considerations. Therefore, the magnitude of the DWL in the LMP mechanism is entirely a consequence of the physical network transmission constraints in high-demand load-duration segments. The increase in consumer surplus and decreases in the system operator fee and DWL result in an increase in the net social welfare of the network as the pricing mechanism becomes increasingly liberalised.

The decrease in producer surplus is a result of the changed demand response at individual nodes. Nodes that are now exposed to a higher price than they are under a single network price mechanism consume less. Generators at these locations are always exposed to LMP pricing, which means that they do not profit from this high price to the same extent as they would under a single network price.

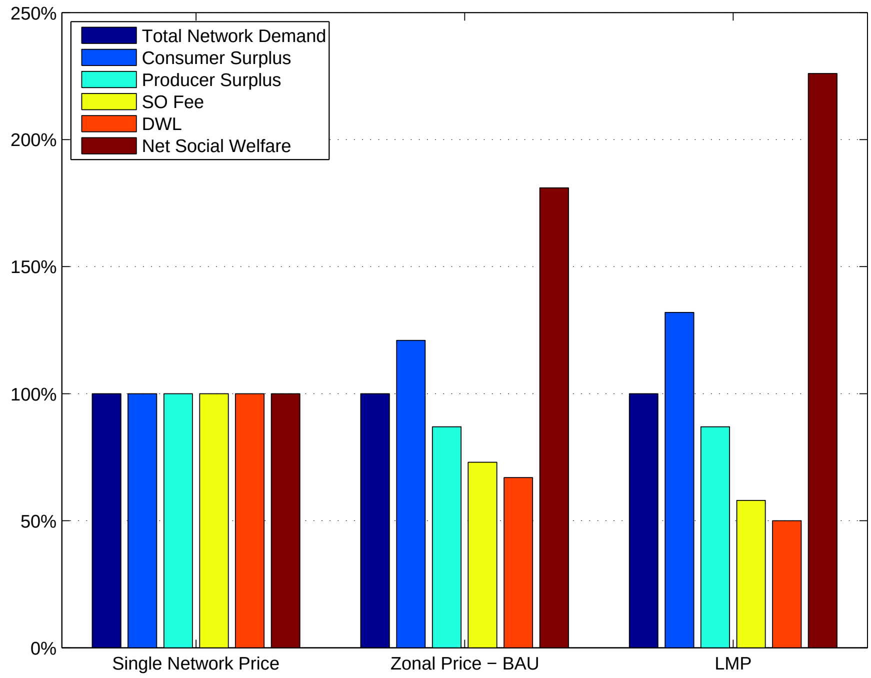


Figure 4.3: Comparison of Key Total Network Welfare Indicators with Increasingly Liberalised Pricing Mechanisms

To demonstrate the consequence for prices under the three pricing mechanism scenarios, Figure 4.4 indicates the trends for the average network price across load-duration segments. Only load-duration segments that begin to indicate areas of transmission congestion have been included, considering that the three mechanisms are identical otherwise. The LMP price for the node representing Sydney has also been included in order to demonstrate the contrast between a locational price in an area that experiences a high degree of transmission congestion with the network average. As Figure 4.4 indicates, the average network price decreases as the pricing mechanism becomes increasingly liberalised. However, the price for the node of Sydney is well above the average network price in the LMP case. This is due to the fact that, under LMP, consumers in Sydney pay for the true cost of the transmission services to their location. Under the two grouped pricing mechanisms, however, these costs are subsidised by other consumers in the network.

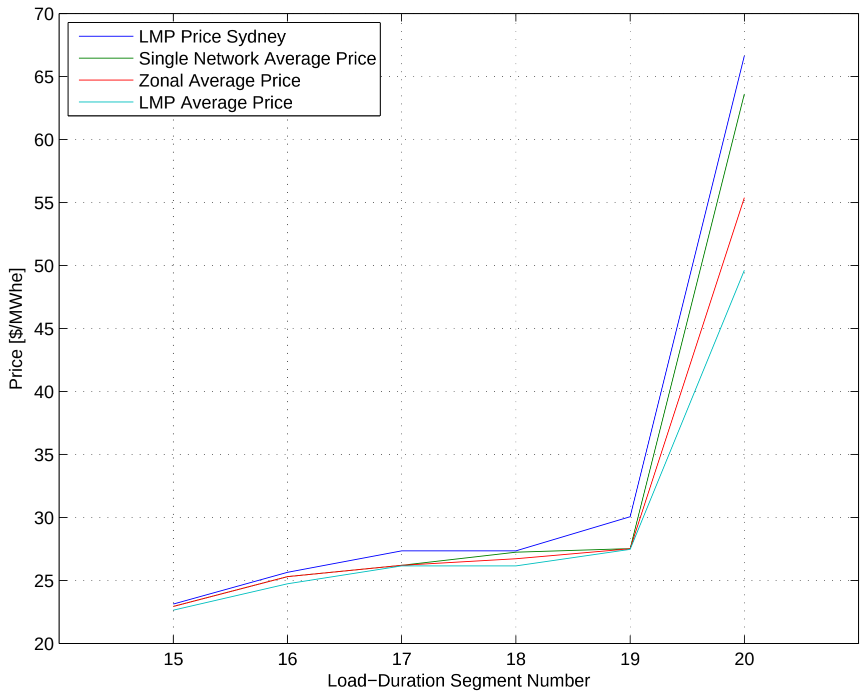


Figure 4.4: Comparison of Average Network Price under Different Pricing Mechanisms

Figure 4.5 shows the demand response at individual nodes in the network for each of the pricing mechanisms, with each scenario referenced to the single network price mechanism. Each of the 16 nodes in this figure is represented by a single vertical bar. The nodes have been grouped according to their retailer zone allocation, as discussed in Section 1.4. In the zonal pricing mechanism, as expected, all nodes within a zone display the same total demand response to the further liberalised pricing mechanism. Under the LMP mechanism however, every node has a different response according to its respective price signals. Interestingly, in the LMP scenario, only the node representing Sydney displays a reduction in overall demand on account of the better price signal. Compared to the zonal pricing mechanism, it is clear that all other nodes in the same zone as Sydney are subsidising Sydney's consumers. The LMP scenario also indicates the extent to which Sydney dominates the total network demand. The small decrease in demand in Sydney is compensated by the often significant increases in demand at every other node, bearing in mind that total network demand is constant across the three scenarios.

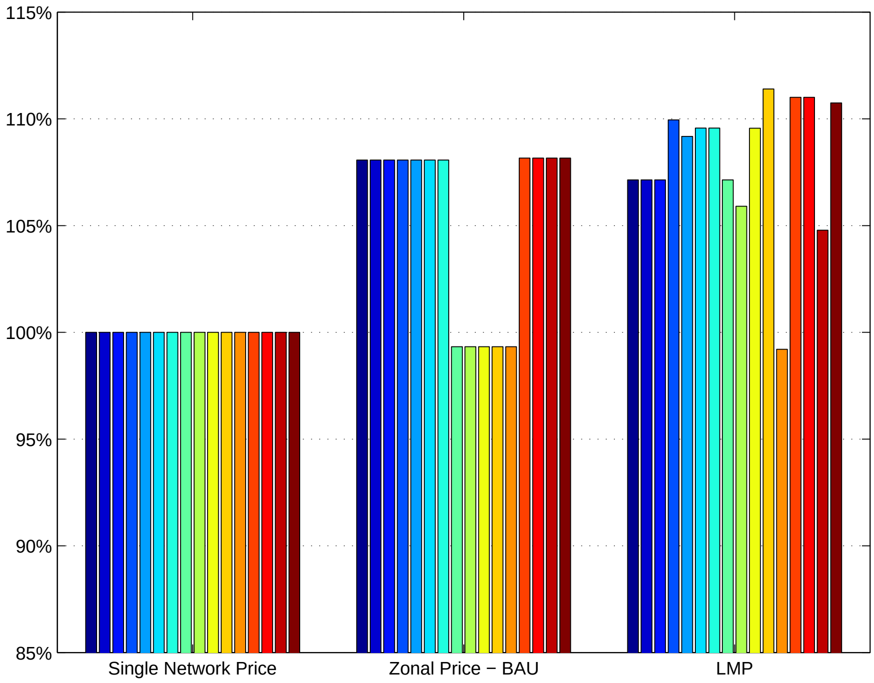


Figure 4.5: Change in Node Demand Response under Different Pricing Mechanisms

Figure 4.5 can also be used as a tool to efficiently aggregate nodes together for a zonal pricing mechanism. It is clear from the LMP scenario that the node representing Sydney should be a stand-alone zone under a zonal pricing mechanism. Otherwise, nodes should be grouped into zones according to their relative demand response. To illustrate this, a model simulation was run in which new zone definitions were made according to Table 4.1. These new zone allocations were made by grouping nodes with equivalent demand responses based on observations from Figure 4.5.

Figure 4.6 demonstrates that this new zone allocation is superior to the previous allocation. Consumer surplus and net social welfare are increased, while producer surplus, the system operator fee and DWL are all reduced relative to the BAU zone allocation. Furthermore, this new zone allocation approaches that of LMP in terms of these key welfare indicators. The reason for this improvement is the improved grouping of nodes into areas that are bounded by transmission constraints. When allocating zone boundaries, efforts should be taken to limit potential for transmission congestion within a zone. Instead, the points in the network at which a transmission constraint is likely to occur

Table 4.1: BAU and New Zone Allocations of Nodes

Retailer	BAU Node Allocation
Country Energy	$n1$, $n2$, $n3$, $n13$, $n14$, $n15$, $n16$
Energy Australia	$n4$, $n5$, $n6$, $n7$, $n8$
Integral Energy	$n9$, $n10$, $n11$, $n12$

Zone	New Node Allocation
z1	$n1$, $n2$, $n3$, $n4$, $n5$, $n11$
Sydney	$n8$
z2	$n6$, $n7$, $n9$, $n10$, $n12$, $n13$, $n14$, $n15$, $n16$

should define the boundary of zones so that all nodes within a zone are fairly exposed to the same price. Such an approach to zone allocation is referred to as 'Flow-Based Market Coupling' (FBMC) (Krause, 2007). This demonstrates that a pricing mechanism can approach the benefits of LMP without the practical implementation, logistical and administrative difficulties of LMP.

Significant net social welfare gains can be made with an increasingly liberalised pricing mechanism that better reflects both the temporal and spatial component of delivering electricity. Ideally, such a pricing mechanism would take the form of LMP, where each node in the network is exposed to a different locationally-dependent price, resulting in the most efficient allocation of transmission resources. However, there are practical limitations regarding the extent to which a network can be disaggregated. Allocating nodes into single price zones can be a suitable compromise with welfare benefits approaching that of LMP. By modelling a power market with a LMP mechanism, policy makers can make more informed decisions with respect to grouping nodes together and defining single price boundaries for the more practical zonal pricing mechanism.

4.2 Implementation of a Carbon Price

The policy of applying a price to carbon dioxide equivalent emissions has generated widespread debate around the world. The intended effect of a carbon price policy is to send the correct price signals through the economy for each unit of carbon emitted and, in doing so, correct markets for this environmental externality. Such a policy has significant implications for power markets considering the widespread use of fossil-based fuels with significant carbon emissions per unit of electricity delivered. Exactly how this price signal is appropriated through power markets is not obvious, and neither are the resulting changed outcomes. Therefore, the capacity to model such policies is key to understanding their true consequences and correctly structuring their application in such a way that allows their intended effects to be realised. This model examines the application of a carbon price by way of a flat carbon tax and an emissions cap on generating firms. In both cases, there is no wealth transfer mechanism.

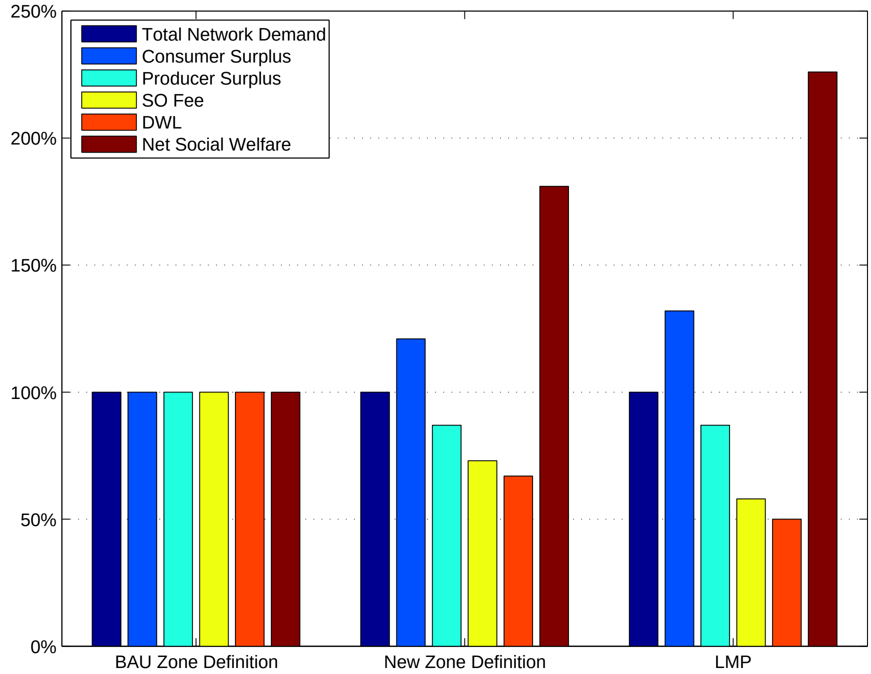


Figure 4.6: Comparison of Key Total Network Welfare Indicators with Improved Zone Allocation

4.2.1 Carbon Tax

Model simulations that apply a carbon tax of \$26/t CO_2 demonstrate the intended effect of reduced emissions. However, these emissions come at a significant cost, with the consumer being hardest hit by way of reduced consumption and higher prices. Figure 4.7 indicates the increase in the average network cost across load segments for the BAU and carbon tax scenarios. Similarly, Figure 4.8 indicates the decrease in total network demand with a carbon tax following the higher price signals.

Figure 4.9 indicates the change in key market outcome with a carbon tax when compared to BAU. As the figure shows, there is a 65 percent reduction in overall emissions, but similarly a 68 percent reduction in overall consumption of electricity. These results suggest that it is the reduction in consumption that is the main driver for a reduction in carbon emissions as opposed to a shift in the market share of generating firms from those with a high carbon intensity to those with lower carbon intensity. However, there is some substitution to less carbon-intensive generators as indicated by the slight reduction in overall carbon intensity.

For the state of NSW, these results are not surprising, considering that the state's entire generation profile is dominated by coal-fired power stations. With a fossil-fuel-heavy generation profile, as indicated in Table 4.2, there is very little opportunity for short term substitution away from carbon-intensive sources. Furthermore, considering that the hydro generators are at the least marginal cost, their output is always maximal and constrained only by their

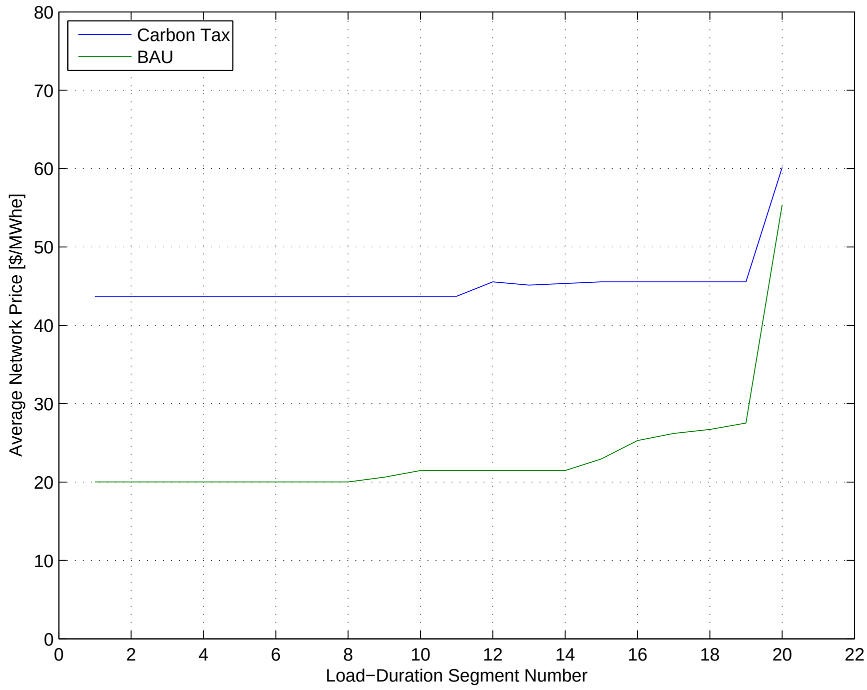


Figure 4.7: Average Network Price Change with a Carbon Tax

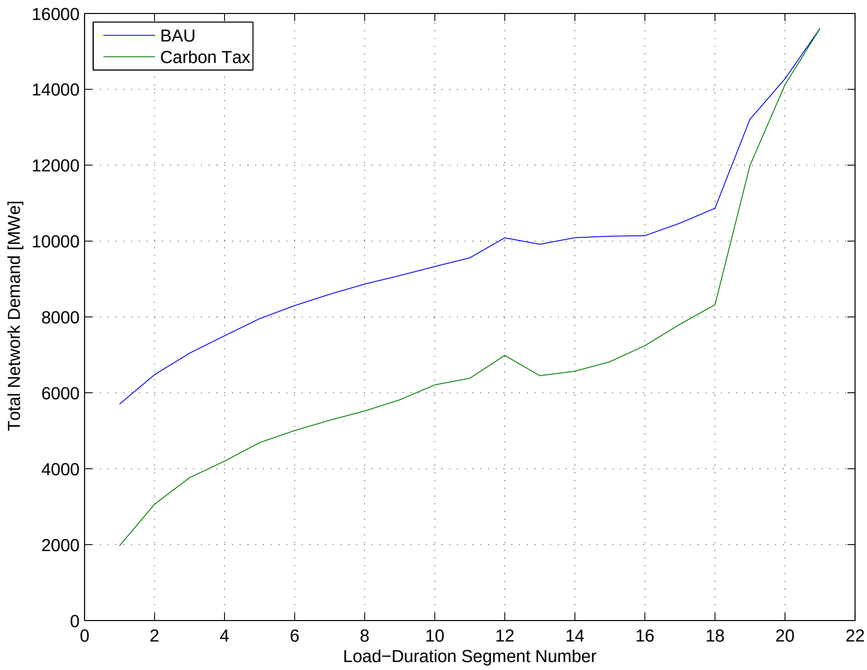


Figure 4.8: Total Network Demand Change with a Carbon Tax

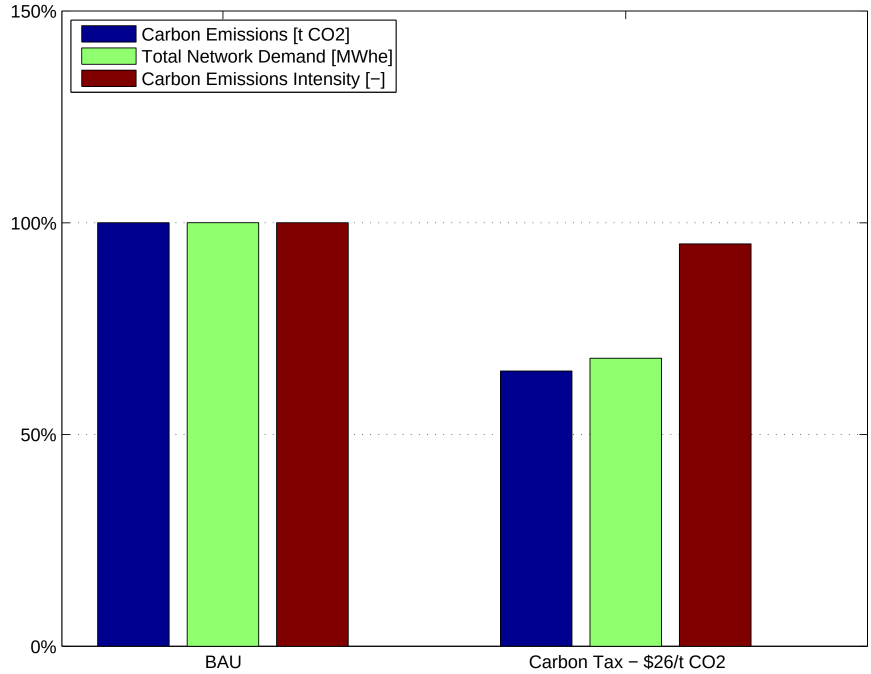


Figure 4.9: Key Outcomes of a Carbon Tax

load-factor limitations. This reinforces the limited opportunity to substitute toward lower carbon-intensive technologies.

Table 4.2: NSW Generation Profile by Fuel Source

Fuel	Capacity [MW_e]	Fraction [%]	$carb_{av}$
Black Coal	11670	64.9	1.019
Natural Gas	2264	12.6	0.660
Fuel Oil	50	0.3	0.964
Hydro	3996	22.2	–

Interestingly, despite very little substitution to the less carbon-intensive technologies, there is significant substitution within the fossil fuel generators. Table 4.3 indicates the change in market share among the generating firms in addition to the generation-weighted firm average marginal cost and carbon intensity. With the application of a carbon tax, the market share shifts toward those generators with a lower marginal cost and a relatively low carbon intensity. In effect, a flat carbon tax contributes to the marginal cost of a generator by multiplying the value of the tax by the carbon intensity of each generator – $PE \times carb_i$. This results in a new effective marginal cost for each generator, as indicated by the $mc_{f,ef}$ term in Table 4.3.[1] These higher marginal costs are ultimately

[1] Calculations of the marginal cost for and carbon intensity of Macquarie Generation do not

passed on to consumers by way of higher electricity prices.

Table 4.3: Change in Firm Average Marginal Cost and Market Share With a Carbon Tax

Firm	$mc_{f,av}$	$carb_{f,av}$	$mc_{f,ef}$	$\Omega_{f,BAU}$	$\Omega_{f,Tax}$
Macquarie Generation	14.71	1.030	41.50	43.7%	63.9%
Eraring Energy	19.57	0.999	45.54	25.5%	6.8%
Delta Electricity	30.45	0.976	55.81	25.2%	15.9%
Snowy Hydro	6.15	–	6.15	3.8%	5.5%
Redbank Project	13.60	1.213	45.14	1.4%	1.0%
TRUenergy	28.43	0.472	40.70	0.4%	6.8%
Marubeni Australia	39.18	0.575	54.13	0.1%	0.1%
Origin Energy	79.96	0.737	99.11	0.0%	0.0%

With the reduced overall consumption, generators must also reduce their output. With reduced overall output, the generators with a lower effective marginal cost profit the most. Specifically, Macquarie Generation takes the market share of Eraring Energy and Delta Electricity by jumping to 63.9 percent of total market share. In the absence of a carbon tax, Macquarie Generation is constrained by its capacity and load factor, which means it cannot profit further from its lower marginal cost. However,with reduced consumption under a carbon tax, these physical constraints become less binding, allowing for this significant change in market share. TRUenergy, with its low carbon intensity, becomes more competitive and increases its market share. Snowy Hydro actually maintains constant absolute output but increases market share with the decrease in total demand. Despite its low initial marginal cost, Redbank Project is penalised in market share on account of its very high carbon intensity.

As discussed, this model provides no opportunity for wealth distribution. Consumers would ordinarily be compensated for higher electricity prices through the tax revenue generated and income tax breaks. Therefore, the significant reduction in consumption observed in this model is not considered highly realistic. However, this model does demonstrate the shift in the marginal generators that would occur under a carbon tax, showing which generators are likely to be priced out of the market and which are likely to profit further. Such analysis can also be used to consider the implications for anti-competitive behaviour with increased market share of some firms. The model also indicates the limited extent to which substitution to lower carbon-intensive sources can occur in the short term due to NSW's fossil-fuel-dominated generation profile. These are important considerations for policy makers attempting to price carbon by way of a carbon tax while achieving meaningful reductions in carbon emissions without excessively impacting consumers.

include the Hunter Valley GT generators. With such a high marginal cost, inclusion of these generators would distort the stated figures despite the fact that they do not feature in the market. Similarly, the Kangaroo Valley and Bendeela hydro-generators for Eraring Energy are not included, as hydro-generators do not feature in the carbon market.

4.2.2 Emissions Cap

In the absence of a wealth transfer mechanism, permit trading is not possible in this model. Therefore, a firm-level emissions cap, in effect, applies an additional capacity constraint that increases the marginal cost of generation through a shadow price on carbon emissions. A carbon tax of \$26/t CO_2 achieved a reduction in total carbon emissions of 64.8 percent. By way of comparison, an emissions cap of 64.8 percent was applied to each firm based on its BAU emissions. This results in a market share allocation, as in Table 4.4.

Table 4.4: Firm Market Share under Different Carbon Price Scenarios

Firm	$\Omega_{f,BAU}$ [%]	$\Omega_{f,Tax}$ [%]	$\Omega_{f,Cap\,64.8\%}$ [%]
Macquarie Generation	43.7	63.9	43.1
Eraring Energy	25.5	6.8	24.6
Delta Electricity	25.2	15.9	24.9
Snowy Hydro	3.8	5.5	5.6
Redbank Project	1.4	1.0	1.4
TRUenergy	0.4	6.8	0.4
Marubeni Australia	0.1	0.1	0.1
Origin Energy	0.0	0.0	0.0

Compared to a carbon tax, an emissions cap achieves a more equitable distribution of market share that better corresponds to the BAU case. However, simply limiting firm emissions without providing the opportunity to trade emissions permits results in a less efficient outcome than applying a carbon tax alone. Without permit trading, low-carbon-intensity firms with high marginal cost do not have the opportunity to sell their right to emit to lower marginal cost generators, where it is profitable to do so. However, the results of this model can indicate which firms would seek to purchase and which would seek to sell emissions permits if it were possible to do so. Table 4.5 indicates the value of each firm's emissions and the generation-weighted average. This average value reveals the price at which permits would be traded.

Table 4.5: Firm Emissions Value and Generation Weighted Average

Firm	Emissions Value [\$/t CO_2]	Trade
Macquarie Generation	26.36	Purchase
Eraring Energy	24.35	Sell
Delta Electricity	23.84	Sell
Redbank Project	24.73	Sell
TRUenergy	33.66	Purchase
Marubeni Australia	54.55	Purchase
Average - Traded Price	25.21	–

As Table 4.5 indicates, firms with an emissions value above the average will look to purchase permits and those with a value below the average will look to sell emissions permits. The value that above-average firms place on an additional unit of emissions is worth more to them than the cost of purchasing this additional right to emit. The opposite applies foe firms below the average. Through trade, the average price will converge until firms are bound by their physical constraints or are indifferent between purchasing or selling the right to emit further. In this way, the least cost reduction in carbon emissions is achieved.

4.3 City of Sydney Distributed Generators

In the City of Sydney's proposal to install distributed generators in the city centre, three of the stated aims are to reduce greenhouse gas emissions, secure energy supply and mitigate peak transmission congestion. With respect to securing supply and mitigating peak transmission congestion, model simulations indicate that these aims can be partly achieved by implementing the distributed generation proposal. With respect to the reduction of carbon emissions, these benefits are less apparent.

Figure 4.10 indicates the welfare, demand and price benefits of additional distributed generator capacity in the City of Sydney for the 20^{th} load-duration segment. The x-axis represents the total capacity of distributed generators in Sydney, while the y-axis represents the percent change from the BAU case of key power market indicators.[2] The model simulations allow for the addition of up to six 50 MW_e CCGT generators, each with a marginal cost of \$44.33/MWh_e to the node representing the City of Sydney ($n8$).

Figure 4.10 demonstrates that the net social welfare for the network increases by 9.0 percent with an additional 300 MW_e DG capacity. This is considerable and actually reflects the reduction in transmission congestion on account of these generators. This increase in welfare is accompanied by a sharp decrease in the congestion fee charged by the system operator (-31.2 percent) and the price for electricity in the zone containing Sydney (-21.0 percent).[3] With the reduction in price, there is a consequent increase in demand in the zone containing Sydney (+3.7 percent) and the entire network (+2.7 percent).

Interestingly, there is insignificant change in the power flow along each of the five lines into Sydney with an increase in installed capacity of DGs. In load-duration segment 20, the utilisation of transmission capacity into Sydney ranges from 96.0 percent to 95.8 percent with the addition of the 300 MW_e DG capacity. In the 'peak' load-duration segment, it remains constant at 98.0 percent utilisation. Physically, therefore, there is no relief in congestion. All lines remain congested with or without the proposed DGs. From a market point of view, however, the demand on any given line is reduced, which decreases the value placed on a unit of electricity transmitted (the shadow cost of transmission). This reduction in value is significant and reflected in the 31.2 percent reduction in the congestion fee charged by the system operator.

In meeting its stated aim of reducing carbon emissions, the benefits of the

[2]It should be noted that in the BAU case, four CCGT generators with a total combined nominal capacity of 176 MW_e already exist, with a marginal cost of \$39.18/MWh_e. These are the Smithfield generators operated by Marubeni Australia.

[3]These model simulations used the zonal pricing mechanism.

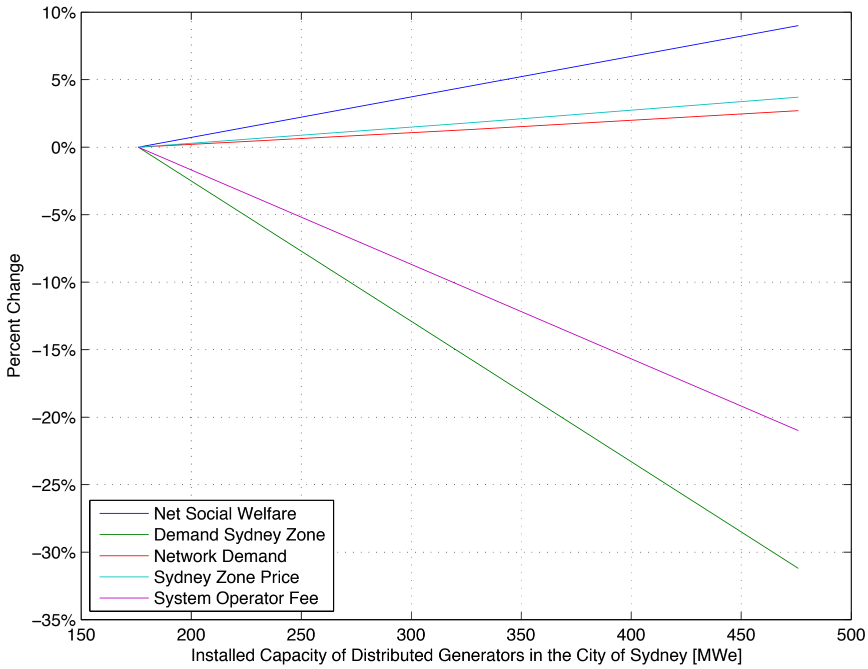


Figure 4.10: Benefits of Distributed Generators in the City of Sydney

City of Sydney DG proposal are less clear. Figure 4.11 indicates that with an addition of DG capacity total system carbon emissions actually increase (albeit very slightly), despite the fact that the the distributed generators have a carbon emissions intensity of 0.48 t CO_2/MWh_e, which is below the portfolio average of 0.58 t CO_2/MWh_e for individual generators.[4] This increase is a result of the increase in system demand on account of the reduced congestion and lower prices. In this case, therefore, when solely considering electrical output, the installation of DGs results in a rebound effect with respect to carbon emissions even if the overall carbon intensity is slightly reduced.

In the model simulations, all generators in the City of Sydney were only dispatched in the penultimate (segment 20) and peak load-duration segments. This means that their total generation over the year is quite limited. This indicates that with the network in its current state, the higher marginal cost of DGs compared to large centralised coal-fired power stations makes them unprofitable to dispatch unless the network becomes congested. This is an important point and clarifies its stated objectives of mitigating peak congestion and improving security of supply. However, this model does not account for the ancillary benefits of DGs such as the ability to satisfy a market for heat and the welfare that may be derived from this. With this secondary market, it may be that these generators operate at a much higher load factor than if servicing an electricity market alone. Additionally, the secondary market for heat may result in overall reduced carbon emissions that are not reflected in

[4]The observed carbon intensity of 0.97 t CO_2/MWh_e is well above the portfolio average, as the absolute electrical output is dominated by high-carbon-intensity coal-fired plants.

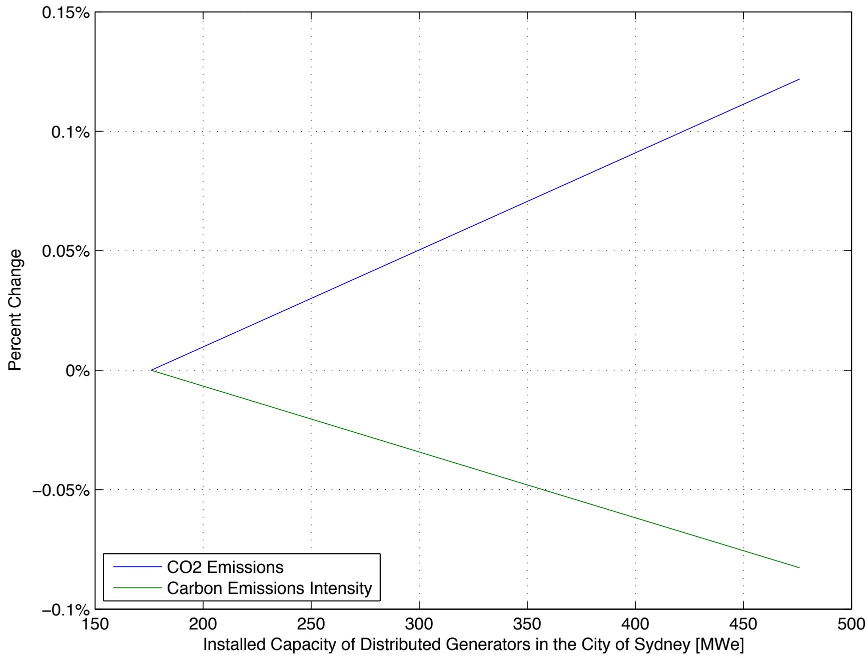


Figure 4.11: Carbon Emissions Consequences of Distributed Generators in the City of Sydney

the aforementioned carbon analysis which considers electrical output only. An economic model examining the interaction between electricity, heat and gas consumption for DGs would indicate how best to operate these units and the additional benefits that cannot be observed when considering electricity alone. Such a model should seek to assess the following issues:

- What is the operating philosophy of these generators – to satisfy a heat market? To contribute to a power market? Or the most profitable economic combination of the two? Generating with a high load-factor to satisfy a market for heat may deflate the price for electricity in periods of low electricity demand. Similarly, operating as a standby generator to mitigate peak congestion (as modelled here) may inadequately service heat customers. Realistically, operating in an optimally profitable way may be difficult given the physical constraints and spot-market uncertainty for electricity, heat and gas.

- How vulnerable are DGs to gas price fluctuations? At what gas price will customers look to substitute away from heat and back to electricity for their heating and cooling requirements? What gas price will prevent DGs operating even in periods of transmission congestion?

- What energy efficiency gains are made in servicing large-scale heating and cooling customers with heat from CHP plants as opposed to using electricity from large centralised coal-fired power plants as is currently the case?

- What carbon emissions reduction benefits are derived from the secondary heat market? In other words, what are the carbon emissions benefits from sourcing heating and cooling requirements from the heat output of the CHP plants compared to using the electrical output of coal-fired power plants, as is currently the case?

- How do any of these observations change in the presence of a more liberalised pricing mechanism or a carbon price? What are the implications (if any) for strategic behaviour among generating firms with the installation of DGs in capacity constrained areas?

Two additional aims of the City of Sydney distributed generator proposal are to make more efficient use of energy and to reduce water consumption in delivering energy services. A model, as described above, that assesses the interaction between electricity, heat and gas could give further insight to these issues. It may also clarify the carbon emissions benefits in allowing the City of Sydney to satisfy its carbon reduction aim.

In summary, this model demonstrates the benefits for mitigating transmission congestion and energy security that can be gained by installing DGs in capacity constrained areas. The carbon emissions benefits are less certain. However, this model is incapable of assessing secondary heat markets or water consumption. Therefore, it cannot realise the potential that distributed generators can have with respect to increased energy resource use efficiency, reduced carbon emissions and reduced water consumption. Consequently, any results derived from the model simulations should be considered in the context of these additional tangible benefits.

4.4 Competitive Framework

The competitive framework under which model simulations take place has a significant impact on the outcome of the power market. In short, generating firms are able to profit significantly by operating as Cournot oligopolists. Model simulations also demonstrate the effect of having more firms in the market place to reduce possibilities for single firms to exert market power. To do this, simulations were run in which each generator is assumed to be an independent single firm behaving according to the Cournot framework. The results of this scenario can then be compared to the BAU case in which there are only eight generating firms, each of which owns many generators in multiple locations (as outlined in Section 1.4).

Figures 4.12 and 4.13 indicate the difference in total network generation and price across all load segments for the cases of perfect competition, Cournot oligopolists, and Cournot oligopolists in which each generator acts as a single firm. These figures demonstrate the significant reduction in total generation and the resulting increase in average network price when firms act as Cournot oligopolists. Of note is the magnitude of the difference between the perfect competition scenario and the two Cournot scenarios. When there are many more firms (as is the case with each generator acting independently), the difference between perfect competition and a Cournot Oligopoly is much reduced compared to the BAU Cournot scenario. With more firms, any single firm is less able to influence the market by submitting reduced capacity bids, resulting in an outcome that is closer to that of perfect competition.

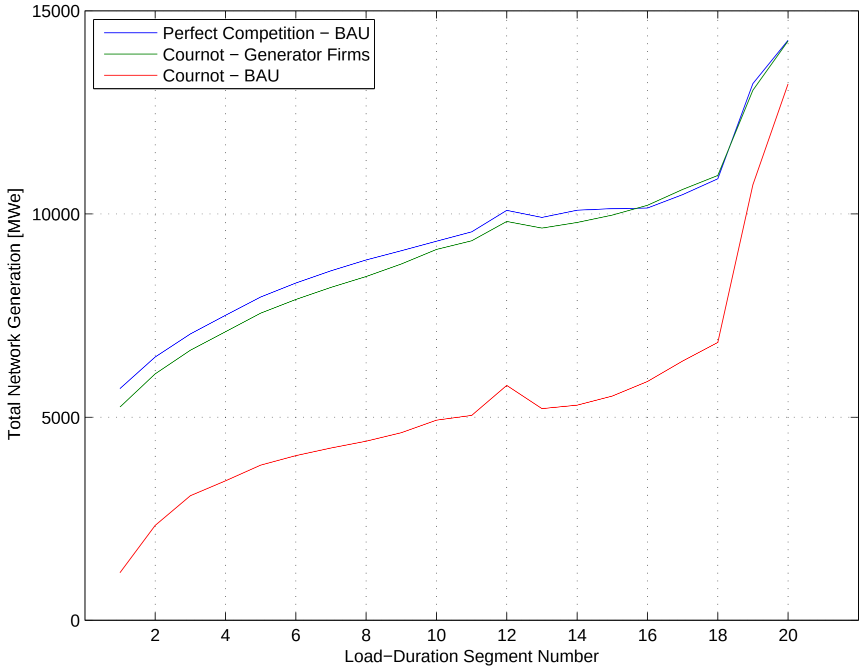


Figure 4.12: Total Network Generation under Perfect Competition and Cournot Oligopoly Frameworks

Figure 4.14 indicates the total network generation and firm profits summed over all load segments for each scenario relative to the perfect competition scenario. Despite the decrease in generation output, firms still achieve greater profits than they would under perfect competition. Furthermore, the percentage increase in profits is greater than the percentage decrease in generation output. This figure again reiterates the convergence toward perfect competition, with an increase in the number of generating firms.

Table 4.6 compares the total output of each firm over the year for the perfect competition and Cournot scenarios. It also indicates the percentage change between the two different scenarios and the average Cournot markup that each firm uses to determine its capacity bid. Despite a decrease in overall generation, only the three largest firms recorded a decrease in output. The other five firms either remain constant or increase their output as the conditions become more favourable for them to do so. This pattern reveals the change in the marginal generating units as those firms with market power decrease their output and force the network demand to be met by a generator with higher marginal cost. In this case, the price of electricity becomes inflated enough in the Cournot Oligopoly scenario for TRUenergy, Marubeni Australia and Origin Energy to profit across more load segments. In a perfectly competitive market, by contrast, the market price was more often below the marginal cost for these generators, making it unprofitable for them to dispatch.

In the case of Snowy Hydro, total output remains constant across both com-

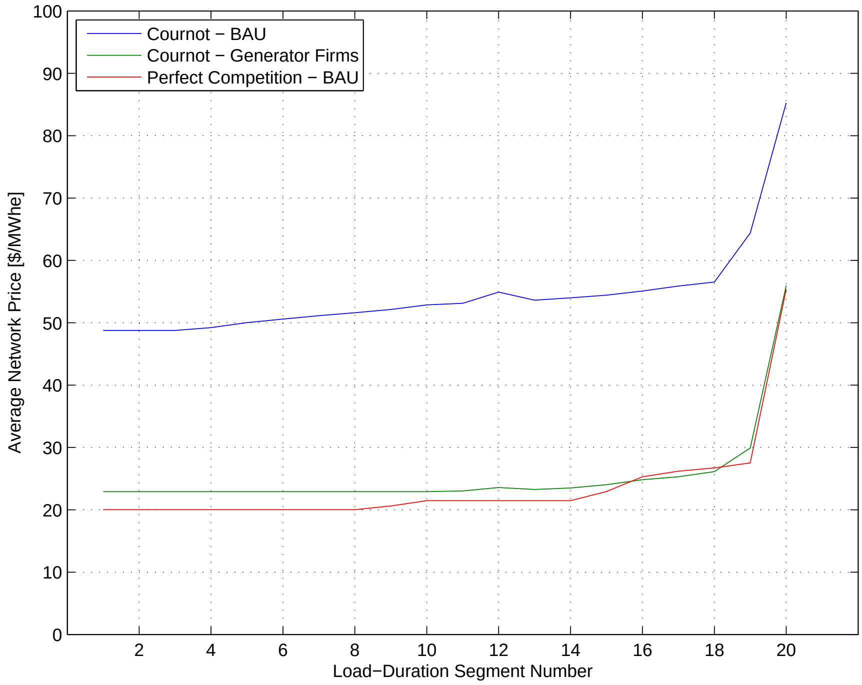


Figure 4.13: Average Network Price under Perfect Competition and Cournot Oligopoly Frameworks

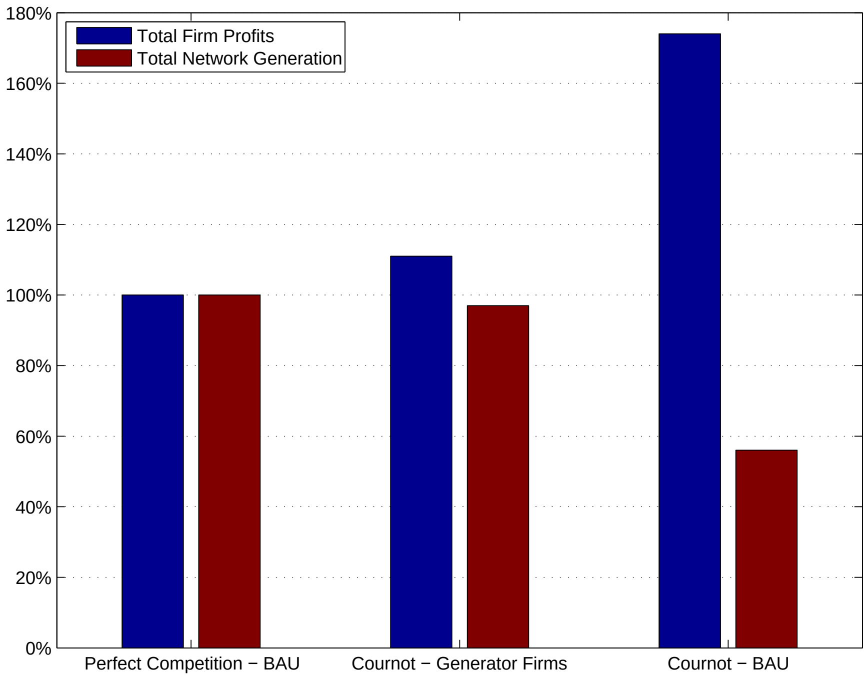


Figure 4.14: Total Network Generation and Firm Profits Relative to BAU Case

petitive frameworks, despite having a relatively high Cournot markup. This is because the generators under the ownership of Snowy Hydro are hydro generators of very low marginal cost. Thus, despite their markup, the industry marginal cost (market clearing price) is almost always above the marginal cost and markup of these generators, resulting in a consistent dispatch decision. In the case of Snowy Hydro, additional generation is prevented by the very low load-factor for hydro generators.

Another interesting trend is the relationship between Redbank Project and TRUenergy, which hold 1 percent and 3 percent of market share by capacity, respectively. In a Cournot framework, the Redbank Project generators are able to profit from the higher prices but are limited by their low nominal capacity and annual load factor. Therefore, in place, TRUenergy generators make up the shortfall left by the Redbank Project and dramatically increase their percentage output to a point where the firm can profit from a relatively high Cournot markup.

Table 4.6: Firm Output Changes Under a Cournot Oligopoly Framework

Firm	Perfect Competition [GWh$_e$]	Cournot Oligopoly [GWh$_e$]	Percent Change [%]	Cournot Markup [−]
Macquarie Generation	35880.96	13675.00	-61.9	0.74
Eraring Energy	20918.88	11468.28	-45.2	0.62
Delta Electricity	20689.18	11623.43	-43.8	0.63
Snowy Hydro	3085.29	3085.29	0.0	0.25
Redbank Project	1169.46	1169.46	0.0	0.07
TRUenergy	355.46	3828.12	976.9	0.23
Marubeni Australia	77.17	1472.38	1807.9	0.09
Origin Energy	0.02	58.46	262513.7	0.03

According to Figure 4.15, generating firms are able to profit to a greater extent as Cournot oligopolists when the pricing mechanism is LMP, as opposed to the BAU zonal pricing mechanism.[5] An explanation for this can be found in the demand response to the LMP pricing scheme. Typically, generators are not located in capacity constrained areas. Therefore, under an LMP mechanism, when these areas are not subsidising the capacity constrained areas, prices are lower and demand response is increased. Conversely, the demand response is reduced in areas where electricity delivery is expensive. These observations raise interesting questions concerning the degree of disaggregation under an LMP pricing mechanism. Despite providing a more efficient pricing mechanism and increase in net social welfare, LMP with high disaggregation of the network may also provide more opportunities for generating firms to exert market power. This has real policy implications for the extent of disaggregation and the structure of single location price areas under an LMP pricing mechanism.

All these trends reveal the significant impacts on market outcomes that can

[5] It should be noted that in Figure 4.15 the two pricing mechanisms are not referenced to each other.

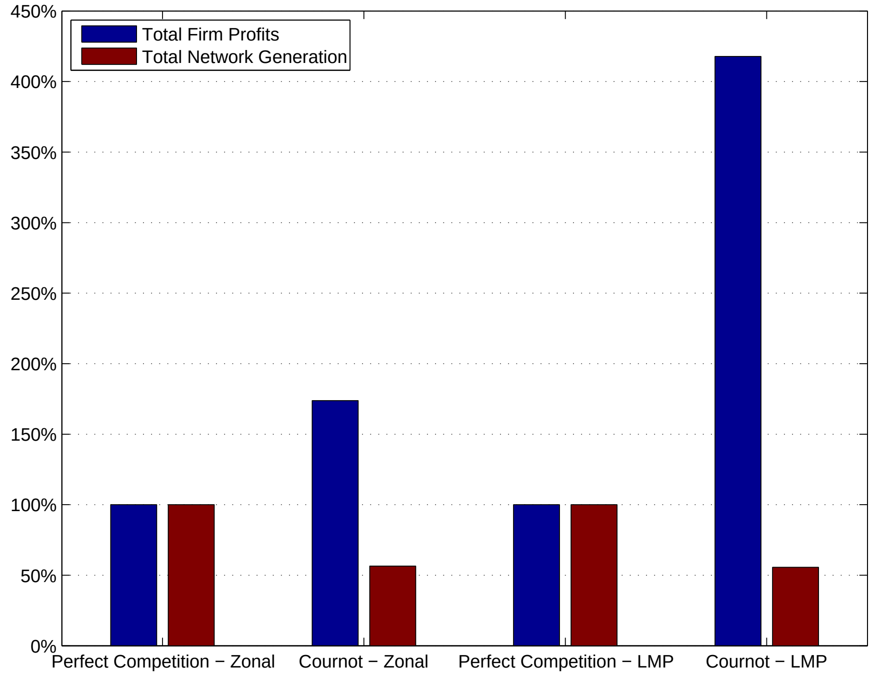


Figure 4.15: Total Network Generation and Firm Profits under Zonal and LMP Pricing Mechanisms

occur when generating firms act as Cournot oligopolists. It also clearly indicates the convergence toward perfect competition that occurs with an increase in participating firms and the potential for generating firms to exert greater market power under LMP pricing mechanisms. For policy makers seeking to create a level playing field for consumers and producers in a power market, it is important to understand the mechanisms by which participants can exert market power when attempting to limit such behaviour. A model such as this is a useful tool to facilitate this understanding and to test policies that will stimulate competition. Policy makers can use comparisons of the market outcomes of simulations modelling perfect competition and Cournot oligopolies to predict or retrospectively deduce anti-competitive behaviour by generating firms.

A further investigation of interest could examine the interaction between the pricing mechanism, multiple locations for generators owned by a single firm, transmission congestion and the competitive framework. Such an investigation could seek to understand if and how generating firms may use or force transmission congestion in different areas of the network to increase profits, and whether different pricing mechanisms would mitigate or encourage such opportunities. It could also be used in conjunction with the above-mentioned zone allocation technique and attempt to establish the optimal number and layout of single locational price areas under an LMP pricing mechanism, while recognising the consequences this has for generating firms seeking to exert market power.

Chapter 5

Conclusions

Liberalised power markets face a number of challenges as policy makers seek more efficient allocation of generation and transmission resources and attempt to correct for environmental externalities. To this end, a number of policy and technology options exist, including improved market pricing mechanisms, implementation of a carbon price and the acceptance of decentralised generation philosophies. It is important to implement these options while simultaneously limiting opportunities for participants to act strategically in order to achieve whole-of-network benefits. This thesis describes the development of an economic model, capable of accounting for real network power flows, to analyse policy and technology options that are relevant to liberalised power markets. Applying this model to the power market representing the state of New South Wales (NSW) in Australia demonstrates its usefulness. The capacity to model and observe likely market outcomes on an ex-ante basis is a useful tool for policy makers seeking to make informed decisions when implementing policy and technology options to liberalised power markets.

The price of electricity for participants in a power market should reflect the temporal and spatial costs of delivering the electricity. This model assumes a dynamic (time-of-use) pricing mechanism that results in the most efficient market outcome with respect to the temporal component of price. With respect to the spatial component of price, model simulations indicate that the movement toward a more liberalised pricing structure in the state of NSW results in improved market outcomes. This liberalised pricing structure (known as Locational Marginal Pricing, or LMP) determines a different price for each node in the network; in doing so, it better rations limited transmission services. However, recognising the practical difficulties in implementing different prices across the whole network, this model demonstrates that the benefits of LMP can be realised with the correct allocation of individual nodes to single price zones. Policy makers can make use of observations from LMP model simulations to assist in effectively defining single price zones.

The implementation of economy-wide price signals for carbon emissions will have significant impacts on power markets. This is particularly true of power markets dominated by fossil fuel-fired generators, such as that of NSW. Model simulations indicate that the implementation of a \$26/t CO_2 carbon tax in NSW significantly reduces the carbon emissions coming from the power generation sector. However, this reduction in carbon emissions is almost entirely driven by the reduction in demand on account of the higher price signals that are fed through to consumers. In NSW, which has a very carbon-intensive generation profile, there are limited opportunities for short term substitution toward cleaner fuels. Over the long term, these higher price signals should induce investment in cleaner generation technologies that can reclaim market share from more polluting technologies.

Policies that encourage decentralised generation recognise opportunities to mitigate peak transmission congestion, improve security of supply for cities, reduce greenhouse gas emissions and make more efficient use of energy resources. Model simulations have assessed these possibilities by modelling a real proposal by the City of Sydney to install distributed generators (DGs) in strategic locations around the city centre. These DGs are capable of contributing to the power market, in addition to creating a secondary heat market for heating and absorptive cooling. The model simulations indicate that, with respect to mitigating transmission congestion and improving security of supply, these DGs are effective. With respect to reducing greenhouse gas emissions and making more efficient use of energy resources, the results are less clear and require further models that are capable of accounting for the tangible benefits derived from the secondary heat market.

It is important to limit the opportunities for any market participants to act strategically in order to achieve efficient market outcomes and a level playing field for consumers and producers. To better understand the mechanisms by which generators can act strategically, this model examines the behaviour of generating firms when they act as Cournot oligopolists. Simulations clearly indicate the anti-competitive behaviour that can result in NSW with only eight generating firms. Interestingly, opportunities for this strategic behaviour can increase with a more liberalised pricing mechanism such as LMP. This is an important consideration for policy makers seeking to efficiently aggregate networks into single price zones. As expected, an increase in the number of firms improves market outcomes and begins to approximate that of perfect competition. Such a finding indicates that policies should be implemented to remove the market entry barriers that are typical of a sector such as generation, in which assets are capital-intensive, irreversible and durable. In addition to predicting anti-competitive behaviour, a model such as this can be used to retrospectively deduce anti-competitive behaviour by generating firms.

5.1 Model Improvements

In its current state, this model is able to provide many realistic insights into power markets; however, a number of features could be included to improve its representation of real power markets.

Fixed-Tariff Pricing for Consumers

This model exposes consumers to dynamic (time-of-use) pricing mechanisms. Although this will become a more realistic pricing structure in the future, it currently does not reflect the true price signals sent to end-use consumers. Instead, most consumers pay a fixed single or dual-tariff price with an on-peak/off-peak price. This fixed tariff could be represented in the consumer linear demand schedule as follows:

$$Q_{n,s} = d^o_{n,s}\left[1 - \epsilon\left(\frac{P_s}{p^o_s} - 1\right)\right] \qquad \perp Q_{n,s}$$

where $P_s = P_1$ in off-peak segments and $P_s = P_2$ in peak segments.

If the model is solved using load-duration segments, it would be necessary to allocate these segments to peak and off-peak periods. If the model is solved using sequential load-segments, the peak and off-peak segments could be defined by the time of day.

The inclusion of fixed-tariff pricing would make for an interesting study to assess the whole-of-network efficiency gains that are to be made when moving to a more liberalised dynamic pricing structure. It might be possible to realise the main benefits of a dynamic structure with the addition of a few more fixed-tariff periods. Modelling such situations provides meaningful insights to policy makers seeking to manage this transition to more highly liberalised consumer tariffs.

Resistive Losses for Transmission Lines

In the current model, the only passage for energy to leave the system is by way of consumption. In practice, there are many other pathways by which energy can leave the system, one of which is the resistive losses in transmitting power. These losses relate to the physical properties of transmission lines, such as the material and the distance. Resistive losses are proportional to the square of the current transmitted along a transmission line l, where the constant of proportionality is the line resistance R_l (the real part of impedance):

$$P_{l,losses} = R_l I_l^2$$

For each transmission line, the inclusion of resistive losses requires the calculation of current and the resulting power loss determined. This represents a second pathway by which energy can leave the system and requires that generators dispatch more energy than is consumed. Therefore, the power loss term needs to be included in the overall energy balance (Equation 2.3) such that:

$$\sum_{f,i,n} X_{f,i,n,s} \geq \sum_{n} Q_{n,s} + \sum_{l} P_{l,losses} \qquad \perp P_{hub,s}$$

Variable Price Elasticity of Demand

The current model assumes a constant price elasticity of demand (ϵ), both across load segments and among nodes. In practice, price elasticity of demand will vary (particularly as a function of time), as the consumer dependency on electricity changes over the course of the day. In this model, it is relatively simple to apply a variable temporal and spatial price elasticity of demand such that $\epsilon = \epsilon(n, s)$. Instead, this feature is limited by access to correct data.

Carbon Permit Trading

As discussed in Sections 2.2.2 and 4.2.2, this model has no opportunity for generators to trade their right to emit under a carbon emissions cap scheme. Therefore, the most efficient market outcome is not realised. Consequently, including carbon permit trading is an important model feature with which to properly assess the market consequences of an emissions cap. To model an emissions permit market, a new variable representing the purchase of carbon permits by a firm f should be introduced (CP_f), which is a free variable with units of t CO_2. This variable should appear in the generator emissions cap constraint (Equation 2.10) as follows:

$$ecap_f + CP_f \geq \sum_{i,n,s \in f} carb_i \cdot X_{f,i,n,s} \cdot t_{seg} \qquad \perp PE_f$$

Across the economy, the trade of carbon permits is zero-sum, such that the total amount purchased by firms equals the total amount sold by other firms.

$$\sum_f CP_f = 0$$

Minimum Generation Limits

An additional minimum generation parameter ($gmin_i$) can be defined for each generator. This parameter specifies the minimum level of output permitted in segments where a choice is made to dispatch such that $gmin_i \leq X_{f,i,n,s} \leq gcap_i$. It will be linked to an additional generation constraint with an associated shadow cost ($PM_{f,i,n,s}$) as follows:

$$X_{f,i,n,s} \geq gmin_i \qquad \perp PM_{f,i,n,s}$$

This constraint will be represented in the generator zero-profit condition (Equation 2.11) as follows:

$$\begin{aligned} mc_i + PG_{f,i,n,s} - PM_{f,i,n,s} + PF_{f,i,n} \cdot t_{seg} + PE_f \cdot carb_i \cdot t_{seg} \\ \geq P_{hub,s} + PT_{n,s} \qquad \perp X_{f,i,n,s} \end{aligned}$$

When including a minimum generation limit, care needs to be taken to ensure that the model still allows for generators to retain the option not to dispatch.

Ramp Rates

As discussed in Section 3.2, ramp-up and ramp-down rates can come at a cost to generators seeking to dispatch more or less power than in a previous load segment. The addition of such conditions better reflects the physical limitations within which most generators must operate. Given the sequential nature of ramp rates, the addition of these constraints would require the model to be solved sequentially without aggregation into representative load-duration segments. This has implications for computing time and the generation of data.

Pumped Storage Systems

Pumped storage systems change the dynamics of a power market. They have the potential to absorb large price fluctuations by consuming power in periods of low prices and dispatching power in periods of high prices. In this way, they provide an effective means by which system operators can manage the balance of supply and demand at any given instant.

Modelling of pumped storage systems requires feedback between the load factor of the generator and the power consumed/dispatched. When power is consumed by the pumped storage system, the load-factor is 'regenerated', and vice-versa for power dispatched. When modelling these systems, care should be taken that consumption and dispatch cannot occur simultaneously. In any given load segment, these generators can either consume or dispatch, but not both.

Although pumped storage systems are not common place in Australia, they have significant penetration in other power markets in the world, including Europe. Therefore, modelling of these power markets without a means to model pumped storage systems is limited.

Secondary Reserve Capacity Market

Most power markets require many generators to hold capacity in reserve, which the system operator can call upon at short notice in order to balance supply and demand. This forces some generators to dispatch less than they otherwise would have. As a result, reserve capacity held by generators is compensated for by way of capacity payments or by the ability to profit through a secondary reserve capacity market. In this secondary market, generators bid on price and quantity for their capacity held in reserve, from which they will profit if it is required by the system operator. This model has not attempted to include reserve capacity markets or capacity payments, but they are a necessary component of most liberalised power markets.

Price Bidding by Generators

Generators in this model are only able to make capacity bids. The system operator has complete visibility of the marginal cost of generating units and will clear the market based on the least-cost dispatch and the capacity bids provided. In practice, however, generators make price and capacity bids to the system operator, who clears the market accordingly. Therefore, the inclusion of price bidding is more representative of reality, but is not a trivial adaptation. Price bidding by generators would require a complete change in the structure of the model.

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Appendix A

NSW Transmission Network Details

A.1 List of Sets, Parameters and Variables

Tables A.1, A.2 and A.3 list the sets, parameters and variables used to characterise and model the NSW transmission network. All variables are listed as upper-case letters and parameters as lower-case letters. Sets are subscripted. Not all parameters are used directly in the model but are instead used to compute model parameters. It has been specified whether parameters are defined exogenously or computed. Where appropriate, all exogenously defined data are published in the following sections.

Table A.1: List of Sets

Symbol	Significance
f	Firm
i	Generator
n	Node
z	Zone
s	Load segment
l	Transmission line
c	Transmission circuit

A.2 Network Topology

Figure A.1 indicates the transmission connections for the NSW Electricity Network. This figure is not to scale; instead, node positions have been adjusted in the diagram for clarity. The 'Great Circle Distance' was used to calculated the distances between nodes of known latitude and longitude, as specified in Table A.4. This network topology is the same as that used for a model developed by the University of Queensland (2009).

Table A.2: List of Parameters

Symbol	Significance	Source	Units
t_{seg}	Time per load segment	Exogenous	hrs
pop_n	Node population	Exogenous	-
loc_n	Node location	Exogenous	Lat., Long.
p_s^o	Benchmark network price	Exogenous	$\$/MWh_e$
$load_s^o$	Total network demand	Exogenous	MWh_e
$d_{n,s}^o$	Benchmark network demand	Computed	MWh_e
ϵ	Price elasticity of demand	Exogenous	-
$\eta_{i,\%}$	Generator heat rate	Exogenous	-
$\eta_{i,fuel}$	Generator heat rate	Computed	-
pf_i	Fuel cost	Exogenous	$/GJ fuel
vc_i	Variable cost	Exogenous	$\$/MWh_e$
mc_i	Short-run marginal cost	Computed	$\$/MWh_e$
$gcap_i$	Nominal capacity	Exogenous	MW_e
$fcap_i$	Load factor	Exogenous	-
$em_{com,i}$	Combustion emissions	Exogenous	kg CO_2/GJ fuel
$em_{fug,i}$	Fugitive emissions	Exogenous	kg CO_2/GJ fuel
$carb_i$	Carbon emissions	Computed	t CO_2/MWh_e
$ecap_f$	Firm total annual carbon emissions	Computed	t CO_2/yr
$volt_{l,c}$	Transmission circuit nominal voltage	Exogenous	kV
$tcap_{l,c}$	Transmission circuit nominal capacity	Exogenous	MW_e
$tcap_l$	Transmission line capacity	Computed	MW_e
$ptdf_{l,n}$	Power transfer distribution factor	Computed	-
$flow_l$	Power flow along a transmission line	Computed	MW_e

Table A.3: List of Variables

Symbol	Significance	Units
P_s	Price	$\$/MWh_e$
$P_{z,s}$	Zone price (single network price for one zone case)	$\$/MWh_e$
$P_{hub,s}$	Market clearing price	$\$/MWh_e$
$PC_{l,s}^+$	Shadow price of congestion – positive direction	$\$/MWh_e$
$PC_{l,s}^-$	Shadow price of congestion – negative direction	$\$/MWh_e$
$PT_{n,s}$	Transmission congestion fee	$\$/MWh_e$
$PG_{f,i,n,s}$	Shadow price of generation capacity	$\$/MWh_e$
$PF_{f,i,n}$	Shadow price of load factor	$\$/MW_e \cdot h^2$
PE_f	Shadow price of firm carbon emissions	$\$/t\ CO_2 \cdot h$
$Q_{n,s}$	Node demand	MW_e
$Y_{n,s}$	Node net-injection	MW_e
$X_{f,i,n,s}$	Generation	MW_e
$\Omega_{f,s}$	Firm market share	-

Figure A.1: NSW Transmission Network Topology Labels

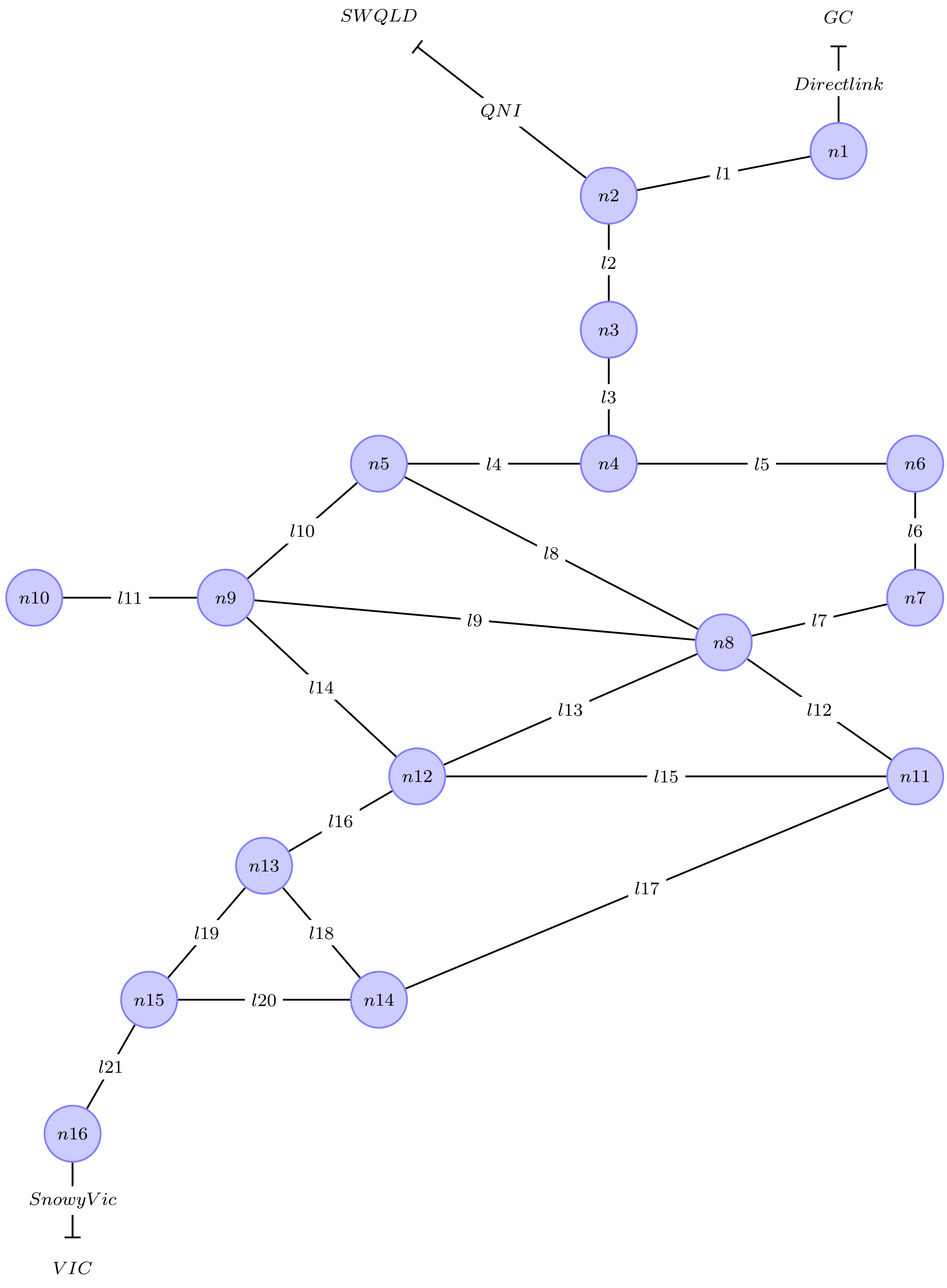

Table A.4: Node Names, Labels and Coordinates

Node Name	Node Label	Latitude	Longitude
Gold Coast	GC	28° 14' 57.38" S	153° 14' 57.38" E
South West QLD	SWQLD	27° 57' 58.06" S	150° 49' 56.39" E
Lismore	n1	28° 49' 00.00" S	153° 17' 00.00" E
Armidale	n2	30° 30' 51.63" S	151° 40' 01.07" E
Tamworth	n3	31° 05' 27.91" S	150° 55' 49.35" E
Liddell	n4	32° 24' 09.90" S	151° 01' 05.93" E
Bayswater	n5	32° 40' 22.20" S	150° 57' 14.42" E
Newcastle	n6	32° 55' 00.00" S	151° 45' 00.00" E
Central Coast	n7	33° 25' 32.28" S	151° 20' 31.50" E
Sydney	n8	33° 52' 08.05" S	151° 12' 25.53" E
Mt Piper	n9	33° 24' 40.62" S	150° 03' 53.77" E
Wellington	n10	32° 33' 20.23" S	148° 56' 33.99" E
Wollongong	n11	34° 25' 00.00" S	150° 52' 60.00" E
Marulan	n12	34° 42' 34.82" S	150° 00' 28.59" E
Yass	n13	34° 50' 32.97" S	148° 54' 41.80" E
Canberra	n14	35° 18' 29.00" S	149° 07' 28.00" E
Tumut	n15	35° 18' 03.84" S	148° 13' 26.19" E
Murray	n16	36° 29' 17.49" S	148° 21' 37.36" E
Victoria	VIC	36° 28' 25.78" S	147° 01' 12.95" E

For the purposes of allocating nodes to zones, the geographic coverage areas of the three electricity retailers in NSW and the states of Queensland and Victoria have been used according to Table A.5.

Table A.5: Zone Allocations of Nodes According to NSW Retailers

Retailer	Zone Label	Nodes
Queensland	$zQLD$	GC, $SWQLD$
Country Energy	zCN	$n1$, $n2$, $n3$, $n13$, $n14$, $n15$, $n16$
Energy Australia	zEA	$n4$, $n5$, $n6$, $n7$, $n8$
Integral Energy	zIN	$n9$, $n10$, $n11$, $n12$
Victoria	$zVIC$	VIC

A.3 Generators

All details and data for the generators modelled in the NSW transmission network can be found in Tables A.6 and A.7. Generators are grouped according to location.

Table A.6: Generator Location, Firm, Type and Fuel

Generator	Location	Firm	Type	Fuel
Bayswater 1	Bayswater	Macquarie Generation	Steam turbine	Black coal
Bayswater 2	Bayswater	Macquarie Generation	Steam turbine	Black coal
Bayswater 3	Bayswater	Macquarie Generation	Steam turbine	Black coal
Bayswater 4	Bayswater	Macquarie Generation	Steam turbine	Black coal
Hunter Valley GT 1	Bayswater	Macquarie Generation	OCGT	Fuel oil
Hunter Valley GT 2	Bayswater	Macquarie Generation	OCGT	Fuel oil
Liddell 1	Liddell	Macquarie Generation	Steam turbine	Black coal
Liddell 2	Liddell	Macquarie Generation	Steam turbine	Black coal
Liddell 3	Liddell	Macquarie Generation	Steam turbine	Black coal
Liddell 4	Liddell	Macquarie Generation	Steam turbine	Black coal
Redbank	Liddell	Redbank Project	Steam turbine	Black coal
Eraring 1	Central Coast	Eraring Energy	Steam turbine	Black coal
Eraring 2	Central Coast	Eraring Energy	Steam turbine	Black coal
Eraring 3	Central Coast	Eraring Energy	Steam turbine	Black coal
Eraring 4	Central Coast	Eraring Energy	Steam turbine	Black coal
Munmorah 3	Central Coast	Delta Electricity	Steam turbine	Black coal
Munmorah 4	Central Coast	Delta Electricity	Steam turbine	Black coal
Vales Point 5	Central Coast	Delta Electricity	Steam turbine	Black coal
Vales Point 6	Central Coast	Delta Electricity	Steam turbine	Black coal
Colongra 1	Central Coast	Delta Electricity	OCGT	Natural gas
Colongra 2	Central Coast	Delta Electricity	OCGT	Natural gas
Colongra 3	Central Coast	Delta Electricity	OCGT	Natural gas
Colongra 4	Central Coast	Delta Electricity	OCGT	Natural gas
Mt Piper 1	Mt Piper	Delta Electricity	Steam turbine	Black coal
Mt Piper 2	Mt Piper	Delta Electricity	Steam turbine	Black coal
Wallerawang 7	Mt Piper	Delta Electricity	Steam turbine	Black coal
Wallerawang 8	Mt Piper	Delta Electricity	Steam turbine	Black coal
Smithfield 1	Sydney	Marubeni Australia	CCGT	Natural gas
Smithfield 2	Sydney	Marubeni Australia	CCGT	Natural gas
Smithfield 3	Sydney	Marubeni Australia	CCGT	Natural gas
Smithfield 4	Sydney	Marubeni Australia	CCGT	Natural gas
Tallawarra	Wollongong	TRUenergy	CCGT	Natural gas
Kangaroo Valley 1	Wollongong	Eraring Energy	Hydro	Hydro
Kangaroo Valley 2	Wollongong	Eraring Energy	Hydro	Hydro
Bendeela 1	Wollongong	Eraring Energy	Hydro	Hydro
Bendeela 2	Wollongong	Eraring Energy	Hydro	Hydro
Uranquinty 1	Tumut	Origin Energy	OCGT	Natural gas
Uranquinty 2	Tumut	Origin Energy	OCGT	Natural gas
Uranquinty 3	Tumut	Origin Energy	OCGT	Natural gas
Uranquinty 4	Tumut	Origin Energy	OCGT	Natural gas

Generator Location, Firm, Type and Fuel (continued)

Generator	Location	Firm	Type	Fuel
Blowering	Tumut	Snowy Hydro	Hydro	Hydro
Tumut 1	Tumut	Snowy Hydro	Hydro	Hydro
Tumut 2	Tumut	Snowy Hydro	Hydro	Hydro
Tumut 3	Tumut	Snowy Hydro	Hydro	Hydro
Guthega 1	Murray	Snowy Hydro	Hydro	Hydro
Guthega 2	Murray	Snowy Hydro	Hydro	Hydro
Murray 1	Murray	Snowy Hydro	Hydro	Hydro
Murray 2	Murray	Snowy Hydro	Hydro	Hydro
Sydney DG 1	Sydney	Sydney DG	CCGT	Natural gas
Sydney DG 2	Sydney	Sydney DG	CCGT	Natural gas
Sydney DG 3	Sydney	Sydney DG	CCGT	Natural gas
Sydney DG 4	Sydney	Sydney DG	CCGT	Natural gas
Sydney DG 5	Sydney	Sydney DG	CCGT	Natural gas
Sydney DG 6	Sydney	Sydney DG	CCGT	Natural gas

Table A.7: Generator Data

Generator	$gcap_i$	$\eta_{i,\%}$	pf_i	vc_i	$em_{com,i}$	$em_{fug,i}$	$gmin_i$	$fcap_i$
Bayswater 1	660	0.36	1.31	1.19	90.20	8.70	264	0.900
Bayswater 2	660	0.36	1.31	1.19	90.20	8.70	264	0.900
Bayswater 3	660	0.36	1.31	1.19	90.20	8.70	264	0.900
Bayswater 4	660	0.36	1.31	1.19	90.20	8.70	264	0.900
Hunter Valley GT 1	25	0.28	30.00	9.61	69.70	5.30		0.975
Hunter Valley GT 2	25	0.28	30.00	9.61	69.70	5.30		0.975
Liddell 1	500	0.34	1.31	1.19	92.80	8.70	200	0.860
Liddell 2	500	0.34	1.31	1.19	92.80	8.70	200	0.860
Liddell 3	500	0.34	1.31	1.19	92.80	8.70	200	0.860
Liddell 4	500	0.34	1.31	1.19	92.80	8.70	200	0.860
Redbank	150	0.29	1.01	1.19	90.00	8.70		0.890
Eraring 1	660	0.35	1.81	1.19	89.50	8.70	264	0.900
Eraring 2	660	0.35	1.81	1.19	89.50	8.70	264	0.900
Eraring 3	660	0.35	1.81	1.19	89.50	8.70	264	0.900
Eraring 4	660	0.35	1.81	1.19	89.50	8.70	264	0.900
Munmorah 3	300	0.31	1.85	1.19	90.30	8.70	120	0.860
Munmorah 4	300	0.31	1.85	1.19	90.30	8.70	120	0.860
Vales Point 5	660	0.35	1.85	1.19	89.80	8.70	264	0.860
Vales Point 6	660	0.35	1.85	1.19	89.80	8.70	264	0.860
Colongra 1	166	0.32	7.42	9.98	51.30	14.20		0.985

Generator Data (continued)

Generator	$gcap_i$	$\eta_{i,\%}$	pf_i	vc_i	$em_{com,i}$	$em_{fug,i}$	$gmin_i$	$fcap_i$
Colongra 2	166	0.32	7.42	9.98	51.30	14.20		0.985
Colongra 3	166	0.32	7.42	9.98	51.30	14.20		0.985
Colongra 4	166	0.32	7.42	9.98	51.30	14.20		0.985
Mt Piper 1	660	0.37	1.86	1.32	87.40	8.70		0.900
Mt Piper 2	660	0.37	1.86	1.32	87.40	8.70		0.900
Wallerawang 7	500	0.33	1.86	1.32	87.40	8.70	200	0.860
Wallerawang 8	500	0.33	1.86	1.32	87.40	8.70	200	0.860
Smithfield 1	38	0.41	4.19	2.40	51.30	14.20		0.955
Smithfield 2	38	0.41	4.19	2.40	51.30	14.20		0.955
Smithfield 3	38	0.41	4.19	2.40	51.30	14.20		0.955
Smithfield 4	62	0.41	4.19	2.40	51.30	14.20		0.955
Tallawarra	460	0.50	3.80	1.05	51.30	14.20		0.950
Kangaroo Valley 1	80	1.00	0.00	7.15	0.00	0.00		0.050
Kangaroo Valley 2	80	1.00	0.00	7.15	0.00	0.00		0.050
Bendeela 1	40	1.00	0.00	7.15	0.00	0.00		0.050
Bendeela 2	40	1.00	0.00	7.15	0.00	0.00		0.050
Uranquinty 1	166	0.32	6.22	9.98	51.30	14.20		0.985
Uranquinty 2	166	0.32	6.22	9.98	51.30	14.20		0.985
Uranquinty 3	166	0.32	6.22	9.98	51.30	14.20		0.985
Uranquinty 4	166	0.32	6.22	9.98	51.30	14.20		0.985
Blowering	80	1.00	0.00	6.15	0.00	0.00		0.090
Tumut 1	330	1.00	0.00	6.15	0.00	0.00		0.150
Tumut 2	286	1.00	0.00	6.15	0.00	0.00		0.150
Tumut 3	1500	1.00	0.00	6.15	0.00	0.00		0.070
Guthega 1	30	1.00	0.00	6.15	0.00	0.00		0.210
Guthega 2	30	1.00	0.00	6.15	0.00	0.00		0.210
Murray 1	950	1.00	0.00	6.15	0.00	0.00		0.090
Murray 2	550	1.00	0.00	6.15	0.00	0.00		0.090
Sydney DG 1	50	0.50	5.83	2.00	51.30	14.20		0.920
Sydney DG 2	50	0.50	5.83	2.00	51.30	14.20		0.920
Sydney DG 3	50	0.50	5.83	2.00	51.30	14.20		0.920
Sydney DG 4	50	0.50	5.83	2.00	51.30	14.20		0.920
Sydney DG 5	50	0.50	5.83	2.00	51.30	14.20		0.920
Sydney DG 6	50	0.50	5.83	2.00	51.30	14.20		0.920

A.4 Transmission Lines

Table A.8: Transmission Line Circuit Data

Line	Circuit	Start Node	End Node	$volt_{l,c}$	$tcap_{l,c}$	AEMO Label
QNI	c1	SWQLD	n2	330	549	8L
QNI	c2	SWQLD	n2	330	549	8M
Directlink	c1	GC	n1	132	60	DC1
Directlink	c2	GC	n1	132	60	DC2
Directlink	c3	GC	n1	132	60	DC3
l1	c1	n1	n2	330	549	8C
l1	c2	n1	n2	330	549	8E
l1	c3	n1	n2	330	892	89
l2	c1	n2	n3	330	892	85
l2	c2	n2	n3	330	709	86
l3	c1	n3	n4	330	983	84
l3	c2	n3	n4	330	892	88
l4	c1	n4	n5	330	1215	33
l4	c2	n4	n5	330	1215	34
l5	c1	n4	n6	330	983	83
l5	c2	n4	n6	330	1220	81
l5	c3	n4	n6	330	1215	82
l6	c1	n6	n7	330	1215	90
l6	c2	n6	n7	330	1215	96
l6	c3	n6	n7	330	1215	93
l7	c1	n7	n8	500	1039	5A1
l7	c2	n7	n8	500	1039	5A2
l7	c3	n7	n8	330	1215	26
l7	c4	n7	n8	330	1143	22
l7	c5	n7	n8	330	1215	25
l7	c6	n7	n8	330	1215	21
l8	c1	n5	n8	330	1215	31
l8	c2	n5	n8	330	1215	32
l8	c3	n5	n8	330	1215	76
l8	c4	n5	n8	330	1215	77
l9	c1	n8	n9	330	1239	71
l9	c2	n8	n9	330	1239	70
l10	c1	n5	n9	500	3289	5A3

Transmission Line Circuit Data (continued)

Line	Circuit	Start Node	End Node	$volt_{l,c}$	$tcap_{l,c}$	AEMO Label
l10	c2	n5	n9	500	3239	5A4
l11	c1	n9	n10	330	572	72
l11	c2	n9	n10	330	915	79
l12	c1	n8	n11	330	1280	11
l12	c2	n8	n11	330	1280	37
l13	c1	n8	n12	330	915	39
l14	c1	n9	n12	330	1220	35
l14	c2	n9	n12	330	1215	36
l15	c1	n11	n12	330	915	16
l15	c2	n11	n12	330	915	8
l16	c1	n12	n13	330	697	4
l16	c2	n12	n13	330	697	5
l16	c3	n12	n13	330	915	61
l17	c1	n11	n14	330	915	3W
l18	c1	n13	n14	330	915	9
l19	c1	n13	n15	330	915	2
l19	c2	n13	n15	330	972	3
l20	c1	n14	n15	330	915	1
l20	c2	n14	n15	330	972	7
l21	c1	n15	n16	330	915	62
l21	c2	n15	n16	330	572	63
l21	c3	n15	n16	330	715	65
l21	c4	n15	n16	330	715	66
SnowyVic	c1	n16	VIC	330	915	60
SnowyVic	c2	n16	VIC	330	508	DDTS_MSS1_330
SnowyVic	c3	n16	VIC	330	508	DDTS_MSS2_330

Appendix B

Supporting Theory

B.1 Competition Theory

B.1.1 Perfect Competition (Varian, 1992)

In a perfectly competitive market, all participants are 'price takers'. That is, a producing firm will act under the belief that the market clearing price is independent of its own actions. In the context of a power market, a generating firm that makes capacity bids does so according to the belief that it is unable to influence the market price. Therefore, the price is independent of the decision variable of generators. By this reasoning, the profit maximisation problem of a generating firm in a power market is as follows:

$$\max_{X_f} \pi_f(X_f) = PX_f - C_f(X_f) \tag{B.1}$$

Taking the derivative of Equation B.1 with respect to X_f gives the first-order conditions as follows:

$$\frac{\partial \pi_f}{\partial X_f} = P - \underbrace{\frac{\partial C_f(X_f)}{\partial X_f}}_{\text{marginal cost } (mc_f)} = 0 \tag{B.2}$$

which indicates that the market clearing price equates to the marginal cost ($P = mc$) in a perfectly competitive market where price is taken as exogenous.

Under a perfectly competitive framework, the net-social welfare of the economy is at its maximum. That is, the sum of the consumer and producer surplus resulting from the gains to trade is maximal. In Figure B.1, the consumer surplus is given by the area underneath the demand curve and above the equilibrium price ($P^* - A - demand$). Similarly, the producer surplus is given by the area above the marginal cost curve and below the equilibrium price ($P^* - A - mc$).

B.1.2 Cournot Oligopoly (Varian, 1992)

A market with a small number of participating firms is subject to strategic behaviour. Specifically, a Cournot equilibrium describes the strategic outcome of

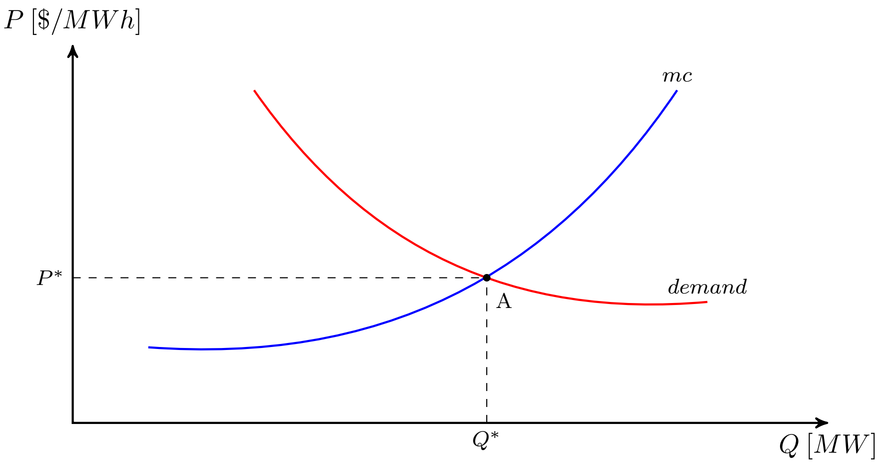

Figure B.1: Equilibrium in a Perfectly Competitive Market

a market where the dispatch decision facing a firm seeking to maximise its profit is based on the dispatch decisions of other firms in the oligopoly. Therefore, a Cournot Oligopoly assumes that participants will use dispatch quantity as their strategic variable. In this way, firms can use market power to restrict output and force a higher market price under the assumption that other firms will not satisfy the created shortfall. This differs from perfect competition, where prices are taken as exogenous. The underlying economic theory of this type of strategic behaviour is described herein.

In a power market, the market price is a function of the total market demand Q_{tot} as follows:

$$P(Q_{tot}) \equiv P(X_1 + X_2 + \cdots + X_f) \tag{B.3}$$

where X_f is the output of a single firm f and $Q_{tot}(X_1, X_2, \cdots, X_f)$ such that $Q_{tot} = X_1 + X_2 + \cdots + X_f$.

Within this context, individual firms will exhibit profit maximising behaviour according to:

$$\max_{X_f} \pi_f(Q_{tot}, X_f) = P(Q_{tot})X_f - C_f(X_f) \tag{B.4}$$

It is evident from Equations B.3 and B.4 that the profits of a firm are dependent on the dispatch decisions of the other participating firms. Firms will therefore seek to maximise their profit by deciding a level of output given a belief of the level of output of the other participants in a 'one-shot game'. The Cournot equilibrium[1] describes the set of outputs $(X_1^*, X_2^*, \cdots, X_f^*)$, where each firm is *correct* in its belief of the output of the other firms. The solution to the Cournot equilibrium can be found by computing the set of outputs such that the first-order conditions of each firm are satisfied:

[1]Also referred to as a Nash-Cournot Equilibrium.

$$\frac{\partial \pi_f}{\partial X_f} = \underbrace{P(Q_{tot}) + \frac{\partial P(Q_{tot})}{\partial X_f} X_f}_{\text{marginal revenue } (mr_f)} - \underbrace{\frac{\partial C_f(X_f)}{\partial X_f}}_{\text{marginal cost } (mc_f)} = 0 \tag{B.5}$$

Equation B.5 can be manipulated to include the market share of participating firms (Ω_f) and the price elasticity of demand (ϵ) by multiplying the marginal revenue terms throughout by $\frac{P(Q_{tot})}{P(Q_{tot})} \frac{\partial Q_{tot}}{\partial Q_{tot}}$ and rearranging terms:

$$\begin{aligned} mc_f &= P(Q_{tot}) + P(Q_{tot}) \underbrace{\frac{X_f}{Q_{tot}}}_{\Omega_f} \underbrace{\frac{\partial P(Q_{tot})}{\partial Q_{tot}} \frac{Q_{tot}}{P(Q_{tot})}}_{1/\epsilon} \underbrace{\frac{\partial Q_{tot}}{\partial X_f}}_{\approx 1} \\ mc_f &= P(Q_{tot}) \left(1 - \frac{\Omega_f}{|\epsilon|}\right) \end{aligned} \tag{B.6}$$

where the price elasticity of demand ϵ is *negative* and assumed to be constant and the $\partial Q_{tot}/\partial X_f \approx 1$ assumption recognises that an infinitesimal change in output of firm f (∂X_f) will result in an equivalent change in industry output (∂Q_{tot}). This is consistent with the Cournot assumption of an individual firm that the output of other participants is taken as given.

The magnitude of the market share term Ω_f is key to considering the outcome of a Cournot Equilibrium. As Ω_f approaches 1, which indicates a monopoly share of the market, the outcome is that of a monopoly where the market price occurs when the marginal revenue (mr_f) of the monopoly firm equates to its marginal cost (mc_f). Conversely, as Ω_f approaches zero, meaning that each firm has an infinitesimal market share, the Cournot equilibrium is that of perfect competition where firms are price takers and the market price is independent of individual firm actions and equals the industry marginal cost. The larger the number of participating firms, the less their market power and the more the equilibrium approaches perfect competition.

In all other instances ($0 < \Omega_f < 1$), a Cournot equilibrium will exist where the output is less than that of perfect competition and the market price is higher than that of perfect competition, but not to the same extent as in a monopoly situation. Rearranging the terms of Equation B.6 gives Equation B.7. The term indicated by 'Cournot mark-up' represents the mark-up in price that occurs in a Cournot Oligopoly when compared to perfect competition where the market price equates to marginal cost.

$$\frac{P(Q_{tot}) - mc_f}{P(Q_{tot})} = \underbrace{\frac{\Omega_f}{|\epsilon|}}_{\text{Cournot mark-up}} \tag{B.7}$$

Figure B.2 indicates the difference in equilibrium quantities and prices between a perfectly competitive market and a monopoly, where P^* and Q^* represent the perfect competition equilibrium price and quantity, respectively. As discussed, the equilibrium in a Cournot Oligopoly will be somewhere between that of a monopoly and perfect competition. That is, the market clearing price will lie somewhere on line segment $D - A$. The extent to which a Cournot

Oligopoly approximates a monopoly depends on the number of firms and their market power.

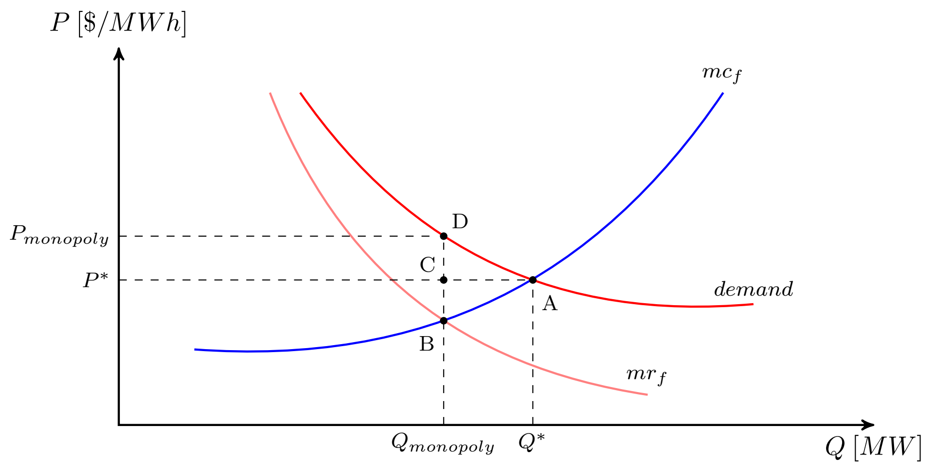

Figure B.2: Equilibrium in a Monopoly

With the potential for mark-up, a Cournot Oligopoly will result in reduced net social welfare when compared to a perfectly competitive market. The magnitude of this reduction in net social welfare is referred to as the dead weight loss (DWL) and can be seen in Figure B.2 as the area given by $A - B - C - D$.[2] The area indicated by $P^* - P_{monopoly} - D - C$ less $A - B - C$ represents the net-increase in producer surplus. The area indicated by $P^* - P_{monopoly} - D - A - C$ represents the net-loss of consumer surplus with $P^* - P_{monopoly} - D - C$, therefore representing the direct transfer of welfare from consumers to producers as a result of the strategic behaviour.

A Cournot model of strategic behaviour differs from other models, such as a Bertrand Oligopoly, where price is the strategically set variable. In a Bertrand equilibrium, firms can strategically price below other firms, while simultaneously expanding output to capture the market share of other participants. In the context of the power market model, a Cournot Oligopoly is a more suitable model of strategic behaviour as generators do not have the opportunity to submit price bids. Furthermore, for power markets where opportunities to quickly increase capacity are limited, Bertrand Oligopoly models have shortcomings (Borenstein et al., 1998). In general, Bertrand models are better suited to markets with inhomogeneous goods where product differentiation is possible. Power markets are strictly homogeneous.

[2]Note again that Figure B.2 represents a monopoly situation. For explanatory purposes, the principles also hold for a Cournot Oligopoly.

B.2 Derivation of the Power Flow Equations (von Meier, 2006)

The complex power at all nodes in a transmission network can be represented by the matrix $\mathbf{S} = \mathbf{V}\mathbf{I}^*$, where $\mathbf{I}^*$ is the complex conjugate of current and the matrix consists of individual node elements i, such that $S_i = V_i I_i^*$. Complex power can be separated into its real and imaginary components $S_i = P_i + jQ_i$.

Ohm's Law states that $\mathbf{V} = \mathbf{I}\mathbf{Z}$, where $\mathbf{Z}$ is the matrix of complex impedances of individual transmission lines. Separated into its real and imaginary components and expressed as individual line elements connecting nodes i and j, the complex impedance becomes $Z_{ij} = R_{ij} + jX_{ij}$[3], where R_{ij} is the line resistance and X_{ij} is the line reactance.

When solving for current, the use of the admittance matrix $\mathbf{Y}$ is more convenient where $\mathbf{Y} = 1/\mathbf{Z}$, such that Ohm's Law becomes $\mathbf{I} = \mathbf{V}\mathbf{Y}$. The complex admittance matrix can be separated into its real and imaginary components and individual matrix elements, such that $Y_{ij} = G_{ij} + jB_{ij}$, where G_{ij} and B_{ij} are the real and imaginary components of the conductance and susceptance matrices, respectively, which can be expressed in terms of line resistance and reactance as follows:[4]

$$G_{ij} = \frac{R_{ij}}{R_{ij}^2 + X_{ij}^2} \qquad \text{and} \qquad B_{ij} = \frac{-X_{ij}}{R_{ij}^2 + X_{ij}^2}$$

Using these relationships, the current between any two connected nodes i and j can be expressed as $I_{ij} = V_j Y_{ij}$ or $I_{ij} = V_j(G_{ij} + jB_{ij})$. Substituting this expression into the equation for complex power and summing over all node connections j into i gives:

$$S_i = V_i I_i^* = V_i(\sum_j Y_{ij} V_j)^* = V_i \sum_j (G_{ij} - jB_{ij}) V_j^* \tag{B.8}$$

With the voltage phasors expressed in longhand notation, this expression becomes:

$$S_i = \sum_j |V_i||V_j|[\cos(\delta_i - \delta_j) + j\sin(\delta_i - \delta_j)](B_{ij} - jB_{ij}) \tag{B.9}$$

where $\delta_i - \delta_j = \theta_{ij}$.

Separating into the real and imaginary components of complex power at node i gives the 'Power Flow Equations' (Equations 3.8 and 3.9) as required:

$$P_i = \sum_j |V_i||V_j|(G_{ij}\cos\theta_{ij} + B_{ij}\sin\theta_{ij})$$

$$Q_i = \sum_j |V_i||V_j|(G_{ij}\sin\theta_{ij} - B_{ij}\cos\theta_{ij})$$

[3] The subscript for node j should not be confused with the complex number imaginary operator j.

[4] For any node j that is not connected to i, the complex admittance $Y_{ij} = 0$.

Appendix C

GAMS Code

C.1 Economic Model

```
$TITLE      Model of the NSW Electricity Network

$eolcom #



* --------------------------------------------------------------------- *
*     DEFINE ENVIRONMENT VARIABLES:
* --------------------------------------------------------------------- *

* Perfect competition (0) or Cournot strategic behaviour (1):
$if not set Cournot     $set Cournot 0
* Normal set of firms (0) single firm generators (1):
$if not set gen_firms   $set gen_firms 0


* Zone price - single/zonal price (0) or LMP (1):
$if not set LMP         $set LMP 0
* Single network zone (0) or use of defined zones (1):
$if not set zone  $set zone 1


* Adjustment to constrain specified transmission lines:
$if not set cons_lines  $set cons_lines l7, l8, l9, l12, l13
$if not set tr_cons     $set tr_cons 0.45
* tcap(lc) = tr_cons*tcap(lc) where lc isset of constrained lines


* Implementation of a carbon tax (1) with specified value:
$if not set ctax  $set ctax 0
$if not set ctax_val    $set ctax_val 26.00
* $26.00/t CO2 is the carbon tax recommended by Garnaut Review 2011


* Implementation of a firm level limit on carbon emissions (1):
$if not set ccap  $set ccap 0
$if not set em_cons     $set em_cons 1.00
* ecap(f) = em_cons*ecap(f) where ecap(f) is benchmark emissions


* Number of distributed generators in the City of Sydney:
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$if not set SDG         $set SDG 6
* Maximum of 6 50MW CCGT generators can be brought online


* Levelised marginal cost — adjusts mc for other expenses:
$if not set mc_lev      $set mc_lev 0
* mc(i) = (1 + mc_lev)*mc(i)


PARAMETERS
      Cournot           Flag for Cournot Oligopoly    / %Cournot% /
      LMP         Flag for LMP                  / %LMP% /
      zone        Flag zonal pricing            / %zone% /
      ctax        Flag carbon tax               / %ctax% /
      ccap        Flag emissions cap            / %ccap% /
      sdg         Flag for DGs in CoS           / %SDG% /;


* ——————————————————————————————————————————————————————————————————— *
*     MODEL:
* ——————————————————————————————————————————————————————————————————— *

SETS  n           Nodes
      z           Zones
      zmap(z,n)   Zone mapping to nodes
      i           Generators
      f           Generating firms
      g(f,i,n)    Firm ownership and location of generators
      l           Transmission lines
      s           Load segments;

ALIAS (n,nn);

SETS  lmap(l,n,nn);


PARAMETERS
*     Time parameters:
      time        Length of analysis period [hrs]
      t_seg(s)    Length of each load segment [hrs]
*     Consumer model parameters:
      d0(n,s)           Benchmark demand [MW_e]
      p0(s)       Benchmark price [$ per MWh_e]
      d_ela       Price elasticity of demand [—]      / 0.4 /
*     Generator model parameters:
      mc(i)       Short—run marginal cost [$ per MWh_e]
      gcap(i)           Nominal generation capacity [MW_e]
      fcap(i)           Load factor limit [MWh_e]
      carb(i)           Carbon emissions intensity [t CO2 per MWh_e]
      ecap(f)           Emissions cap [t CO2 per yr]
*     Transmission line model parameters:
      tcap(l)           Transmission capacity [MW_e]
      ptdf(l,n)   Power transfer distribution factor (PTDF);


VARIABLES
      PHUB(s)           Hub (market clearing) price [$ per MWh_e]
      PZ(z,s)           Zone price [$ per MWh_e]
      Q(n,s)            Demand at node n [MW_e]
      X(f,i,n,s)  Generation [MW_e]
      OME(f,s)    Market share [—]
      PG(f,i,n,s) Capacity rent [$ per MWh_e]
```

```
      PF(f,i,n)   Capacity factor rent [$ per MW_e h^2]
      PEm(f)            Shadow price on emissions [$ per t CO2 per hr]
      Y(n,s)            Net-injection into node [MW_e] - free variable
      PT(n,s)           Congestion fee [$ per MWh_e] - free variable
      PCpos(l,s)  Shadow cost of congestion - pos [$ per MWh_e]
      PCneg(l,s)  Shadow cost of congestion - neg [$ per MWh_e];

NONNEGATIVE VARIABLES   PHUB, PZ, Q, X, OME, PG, PF, PEm, PCpos, PCneg;


EQUATIONS
*     Consumer conditions:
      demand(n,s)       Linear demand schedule for consumers
      p_zone(z,s)       Zone price determination
*     System operator conditions:
      o_mar(s)          Overall market clearing condition
      tcons_pos(l,s)          Transmission capacity constraint - pos
      tcons_neg(l,s)          Transmission capacity constraint - neg
      SO_cost(n,s)            Congestion fee determination
      n_mar(n,s)        Node-level market clearing condition
*     Generator conditions:
      gcons(f,i,n,s)          Nominal generation capacity constraint
      lfcons(f,i,n)           Load factor constraint
      emcons(f)         Firm emissions cap constraint
      GE_prof(f,i,n,s)  Zero-profit condition for generators
      mktsh(f,s)        Market share of firm f;


* ------------------------------------------------------------------- *
*     LINEAR CALIBRATED DEMAND SCHEDULE - LMP/ZONAL PRICE SCENARIOS:
* ------------------------------------------------------------------- *

demand(n,s)..             Q(n,s) =e= d0(n,s)*(1 - d_ela*((
                          (PHUB(s) + PT(n,s))$LMP
                          + sum(z$zmap(z,n), PZ(z,s))$(not LMP)
                                )/p0(s) - 1));


*     Zonal price determination
p_zone(z,s)..             PZ(z,s)*sum(n$zmap(z,n),Q(n,s)) =e=
                          sum(n$zmap(z,n), Q(n,s)*
                                (PHUB(s) + PT(n,s)));


* ------------------------------------------------------------------- *
*     SYSTEM OPERATOR CONDITIONS:
* ------------------------------------------------------------------- *

*     Market Clearance:
*     ----------------
*     Overall generation must satisfy demand
o_mar(s)..          sum((f,i,n)$g(f,i,n), X(f,i,n,s)) =g=
                          sum(n, Q(n,s));


*     Rationing of Transmission Resources:
*     -----------------------------------
*     Transmission within line capacity
tcons_pos(l,s)..  tcap(l) =g= sum(n, ptdf(l,n)*Y(n,s));
tcons_neg(l,s)..  sum(n, ptdf(l,n)*Y(n,s)) =g= -tcap(l);

*     Transmission congestion fee determination
```

```
SO_cost(n,s)..          sum(l, ptdf(l,n)*(PCpos(l,s) - PCneg(l,s)))
                        =e= PT(n,s);

*     Net-injection into a node
n_mar(n,s)..            Y(n,s) =e= Q(n,s)
                        - sum((f,i)$g(f,i,n), X(f,i,n,s));


* ------------------------------------------------------------------ *
*     GENERATOR CONDITIONS:
* ------------------------------------------------------------------ *

*     Nominal generating capacity is limited
gcons(g(f,i,n),s)..     gcap(i) =g= X(f,i,n,s);

*     Total annual generation is limited
lfcons(g(f,i,n))..      fcap(i) =g= sum(s, X(f,i,n,s)*t_seg(s));

*     Firm carbon emissions are limited
emcons(f)..       ecap(f) =g= sum((i,n,s)$g(f,i,n),
                        carb(i)*X(f,i,n,s)*t_seg(s));

*     Generator zero-profit condition
GE_prof(g(f,i,n),s)..   mc(i) + PG(f,i,n,s) + PF(f,i,n)*t_seg(s)
                        + PEm(f)*carb(i)*
                        (1 + (t_seg(s) - 1)$(not ctax)) =g=
                              (PHUB(s) + PT(n,s)) *
                              (1 - (OME(f,s)/d_ela)$Cournot);

*     Market share determination
mktsh(f,s)..            OME(f,s)*sum(n, Q(n,s)) =e=
                        sum((i,n)$g(f,i,n), X(f,i,n,s));


MODEL nsw   / demand.Q, p_zone.PZ, o_mar.PHUB, tcons_pos.PCpos,
              tcons_neg.PCneg, SO_cost.Y, n_mar.PT, gcons.PG,
              lfcons.PF, emcons.PEm, GE_prof.X, mktsh.OME /;



* ------------------------------------------------------------------ *
*     PARAMETER VALUES & INITIAL CONDITIONS:
* ------------------------------------------------------------------ *

* Load data from gdx file:
$gdxin      Outputs\nswdata.gdx
$loaddc     n, i, l, lmap, s, d0, p0, gcap, fcap
$loaddc t_seg, time, mc, carb, tcap, ptdf


* Define zone sets:
$if %zone% == 1 $goto zone_def
* Single network price:
SETS        z           / z /
      zmap(z,n)    / z.n1*n16, z.GC, z.SWQLD, z.VIC /;
$goto skip1
* Retailer zones:
$label zone_def
$loaddc z, zmap
$label skip1
```

```
* Define firm sets:
$if %gen_firms% == 1 $goto firm_def
* Normal firm ownership:
SETS  f           Generating firm labels
                  / "fGC", "fSWQLD", "MAC", "RED", "ERA", "DEL",
                    "MAR", "TRU", "ORI", "SNO", "fVIC", "SYD" /

      g(f,i,n)    Firm ownership and location of generators
                  / "MAC".i1*i6.n5, "MAC".i7*i10.n4,
                    "RED".i11.n4,
                    "ERA".i12*i15.n7, "ERA".i33*i36.n11,
                    "DEL".i16*i23.n7, "DEL".i24*i27.n9,
                    "MAR".i28*i31.n8,
                    "TRU".i32.n11,
                    "ORI".i37*i40.n15,
                    "SNO".i41*i44.n15, "SNO".i45*i48.n16,
                    "fGC"."iGC"."GC", fSWQLD."iSWQLD"."SWQLD",
                    "fVIC"."iVIC"."VIC"
                    "SYD".SDG1*SDG6.n8 /;
$loaddc ecap
$goto skip2
* Individual generator firms:
$label firm_def
$loaddc f, g
ecap(f) = +INF;
$label skip2


* Assign initial conditions:
Q.L(n,s) = d0(n,s);


* Define fixed variable conditions:
Q.FX("SWQLD",s) = 0;
Q.FX("GC",s) = 0;
Q.FX("VIC",s) = 0;
PG.FX(f,i,n,s)$(gcap(i)=+INF) = 0;
ecap(f)$(not ccap) = +INF;
PEm.FX(f)$(ecap(f)=+INF) = 0;
PCpos.FX(l,s)$(tcap(l)=+INF) = 0;
PCneg.FX(l,s)$(tcap(l)=+INF) = 0;


* Adjustment parameters using environment variables:
SETS  lc(l) Constrained transmission lines
            / %cons_lines% /
      dgc(i)      Full set of City of Sydney distributed generators
            / SDG1*SDG6 /
$if   %SDG%==0
      dg(i) Operational distributed generators / SDG1 /;
$if not %SDG%==0
      dg(i) Operational distributed generators / SDG1*SDG%SDG% /;
tcap(lc) = %tr_cons%*tcap(lc);
ecap(f) = %em_cons%*ecap(f);
PEm.FX(f)$ctax= %ctax_val%;
gcap(dgc)$(not SDG) = 0;
gcap(dgc(i))$(not dg(i)) = 0;
mc(i) = (1 + %mc_lev%)*mc(i);


* Solve model:
SOLVE nsw using MCP;
```

C.2 Transmission Network Characterisation Tool

```
$TITLE      NSW Electricity Network Characterisation Tool

$eolcom #



* ──────────────────────────────────────────────────────────────────── *
*      DEFINE REFERENCE PARAMETERS:
* ──────────────────────────────────────────────────────────────────── *

* Reference (slack) node for PTDF calculation:
$if not set ref_node    $set ref_node n8



* ──────────────────────────────────────────────────────────────────── *
*      DEFINE SETS:
* ──────────────────────────────────────────────────────────────────── *

SETS
*      Nodes:
       nnn   Node names
             / "Gold_Coast", "South_West_QLD", "Lismore",
               "Armidale", "Tamworth", "Liddell", "Bayswater",
               "Newcastle", "Central_Coast", "Sydney", "Mt_Piper",
               "Wellington", "Wollongong", "Marulan", "Yass",
               "Canberra", "Tumut", "Murray", "Victoria" /

       n     Node labels
             / "GC", "SWQLD", n1*n16, "VIC" /

       nmap(n,nnn) Map node label to name /
       "GC"."Gold_Coast"
       "SWQLD"."South_West_QLD"
       n1."Lismore",
       n2."Armidale",
       n3."Tamworth",
       n4."Liddell",
       n5."Bayswater",
       n6."Newcastle",
       n7."Central_Coast",
       n8."Sydney",
       n9."Mt_Piper",
       n10."Wellington",
       n11."Wollongong",
       n12."Marulan",
       n13."Yass",
       n14."Canberra",
       n15."Tumut",
       n16."Murray"
       "VIC"."Victoria" /


*      Zones:
       z     Zone labels
             / zQLD, zCN, zEA, zIN, zVIC /

       zmap(z,n)   Map zone labels to nodes /
       zQLD."GC",
       zQLD."SWQLD",
```

```
       zCN.n1*n3,
       zEA.n4*n8,
       zIN.n9*n12,
       zCN.n13*n16,
       zVIC."VIC" /


*      Load segments:
       sss          Load segment names
                    / Segment1*Segment17520 /

       ss           Load segment labels
                    / s1*s17520 /

       smap(ss,sss)       Map load segment label to name
                    / s1*s17520:Segment1*Segment17520 /

       s            Reduced load segment set


*      Generators:
       ii     Generator list
              / "gen_GC", "gen_SWQLD", "Bayswater_1", "Bayswater_2",
                "Bayswater_3", "Bayswater_4", "Hunter_Valley_GT_1",
                "Hunter_Valley_GT_2", "Liddell_1", "Liddell_2",
                "Liddell_3", "Liddell_4", "Redbank", "Eraring_1",
                "Eraring_2", "Eraring_3", "Eraring_4", "Munmorah_3",
                "Munmorah_4", "Vales_Point_5", "Vales_Point_6",
                "Colongra_1", "Colongra_2", "Colongra_3",
                "Colongra_4", "Mt_Piper_1", "Mt_Piper_2",
                "Wallerawang_7", "Wallerawang_8", "Smithfield_1",
                "Smithfield_2", "Smithfield_3", "Smithfield_4",
                "Tallawarra", "Kangaroo_Valley_1",
                "Kangaroo_Valley_2", "Bendeela_1", "Bendeela_2",
                "Uranquinty_1", "Uranquinty_2", "Uranquinty_3",
                "Uranquinty_4", "Blowering", "Tumut_1", "Tumut_2",
                "Tumut_3", "Guthega_1", "Guthega_2", "Murray_1",
                "Murray_2", "gen_VIC", "Sydney_DG_1", "Sydney_DG_2",
                "Sydney_DG_3", "Sydney_DG_4", "Sydney_DG_5",
                "Sydney_DG_6" /

       i      Generator labels
              / "iGC", "iSWQLD", i1*i48, "iVIC", SDG1*SDG6 /

       imap(i,ii)  Map generator label to plant /
       "iGC"."gen_GC",
       "iSWQLD"."gen_SWQLD",
       i1."Bayswater_1",
       i2."Bayswater_2",
       i3."Bayswater_3",
       i4."Bayswater_4",
       i5."Hunter_Valley_GT_1",
       i6."Hunter_Valley_GT_2",
       i7."Liddell_1",
       i8."Liddell_2",
       i9."Liddell_3",
       i10."Liddell_4",
       i11."Redbank",
       i12."Eraring_1",
       i13."Eraring_2",
       i14."Eraring_3",
       i15."Eraring_4",
```

```
       i16."Munmorah_3",
       i17."Munmorah_4",
       i18."Vales_Point_5",
       i19."Vales_Point_6",
       i20."Colongra_1",
       i21."Colongra_2",
       i22."Colongra_3",
       i23."Colongra_4",
       i24."Mt_Piper_1",
       i25."Mt_Piper_2",
       i26."Wallerawang_7",
       i27."Wallerawang_8",
       i28."Smithfield_1",
       i29."Smithfield_2",
       i30."Smithfield_3",
       i31."Smithfield_4",
       i32."Tallawarra",
       i33."Kangaroo_Valley_1",
       i34."Kangaroo_Valley_2",
       i35."Bendeela_1",
       i36."Bendeela_2",
       i37."Uranquinty_1",
       i38."Uranquinty_2",
       i39."Uranquinty_3",
       i40."Uranquinty_4",
       i41."Blowering",
       i42."Tumut_1",
       i43."Tumut_2",
       i44."Tumut_3",
       i45."Guthega_1",
       i46."Guthega_2",
       i47."Murray_1",
       i48."Murray_2",
       "iVIC"."gen_VIC"
       SDG1."Sydney_DG_1"
       SDG2."Sydney_DG_2"
       SDG3."Sydney_DG_3"
       SDG4."Sydney_DG_4"
       SDG5."Sydney_DG_5"
       SDG6."Sydney_DG_6" /


*      Firms:
       ff    Generating firm names
             / "Macquarie_Generation", "Redbank_Project",
               "Eraring_Energy", "Delta_Electricity",
               "Marubeni_Australia", "TRUenergy", "Origin_Energy",
               "Snowy_Hydro", "Sydney_DG" /

       f     Generating firm labels
             / "fGC", "fSWQLD", "MAC", "RED", "ERA", "DEL", "MAR",
               "TRU", "ORI", "SNO", "fVIC", "SYD", fi1*fi48,
               fSDG1*fSDG6 /

       fmap(f,ff)  Map firm label to name /
       "MAC"."Macquarie_Generation",
       "RED"."Redbank_Project",
       "ERA"."Eraring_Energy",
       "DEL"."Delta_Electricity",
       "MAR"."Marubeni_Australia",
       "TRU"."TRUenergy",
       "ORI"."Origin_Energy",
```

```
"SNO"."Snowy_Hydro",
"SYD"."Sydney_DG" /

g(f,i,n)    Firm ownership and location of generators /
fGC.iGC.GC,
fSWQLD.iSWQLD.SWQLD,
fi1.i1.n5,
fi2.i2.n5,
fi3.i3.n5,
fi4.i4.n5,
fi5.i5.n5,
fi6.i6.n5,
fi7.i7.n4,
fi8.i8.n4,
fi9.i9.n4,
fi10.i10.n4,
fi11.i11.n4,
fi12.i12.n7,
fi13.i13.n7,
fi14.i14.n7,
fi15.i15.n7,
fi16.i16.n7,
fi17.i17.n7,
fi18.i18.n7,
fi19.i19.n7,
fi20.i20.n7,
fi21.i21.n7,
fi22.i22.n7,
fi23.i23.n7,
fi24.i24.n9,
fi25.i25.n9,
fi26.i26.n9,
fi27.i27.n9,
fi28.i28.n8,
fi29.i29.n8,
fi30.i30.n8,
fi31.i31.n8,
fi32.i32.n11,
fi33.i33.n11,
fi34.i34.n11,
fi35.i35.n11,
fi36.i36.n11,
fi37.i37.n15,
fi38.i38.n15,
fi39.i39.n15,
fi40.i40.n15,
fi41.i41.n15,
fi42.i42.n15,
fi43.i43.n15,
fi44.i44.n15,
fi45.i45.n16,
fi46.i46.n16,
fi47.i47.n16,
fi48.i48.n16,
fSDG1.SDG1.n8,
fSDG2.SDG2.n8,
fSDG3.SDG3.n8,
fSDG4.SDG4.n8,
fSDG5.SDG5.n8,
fSDG6.SDG6.n8,
fVIC.iVIC.VIC /;
```

```
ALIAS (n,nn,m,mm);

SETS
*      Transmission lines:
       l      Transmission lines
              / "Directlink", "QNI", l1*l21, "SnowyVic" /

       lmap(l,n,nn)      Map transmission lines to connected nodes /
       "Directlink"."GC"."n1",
       "QNI"."SWQLD"."n2",
       l1."n1"."n2",
       l2."n2"."n3",
       l3."n3"."n4",
       l4."n4"."n5",
       l5."n4"."n6",
       l6."n6"."n7",
       l7."n7"."n8",
       l8."n5"."n8",
       l9."n8"."n9",
       l10."n5"."n9",
       l11."n9"."n10",
       l12."n8"."n11",
       l13."n8"."n12",
       l14."n9"."n12",
       l15."n11"."n12",
       l16."n12"."n13",
       l17."n11"."n14",
       l18."n13"."n14",
       l19."n13"."n15",
       l20."n14"."n15",
       l21."n15"."n16",
       "SnowyVic"."n16"."VIC"  /

       c      Transmission line circuits
              / c1*c6 /

       lcmap(l,c)  Map transmission circuits to lines  /
       "Directlink"."c1",
       "Directlink"."c2",
       "Directlink"."c3",

       "QNI"."c1",
       "QNI"."c2",

       "l1"."c1",
       "l1"."c2",
       "l1"."c3",

       "l2"."c1",
       "l2"."c2",

       "l3"."c1",
       "l3"."c2",

       "l4"."c1",
       "l4"."c2",

       "l5"."c1",
       "l5"."c2",
       "l5"."c3",

       "l6"."c1",
```

```
        "l6"."c2",
        "l6"."c3",

        "l7"."c1",
        "l7"."c2",
        "l7"."c3",
        "l7"."c4",
        "l7"."c5",
        "l7"."c6",

        "l8"."c1",
        "l8"."c2",
        "l8"."c3",
        "l8"."c4",

        "l9"."c1",
        "l9"."c2",

        "l10"."c1",
        "l10"."c2",

        "l11"."c1",
        "l11"."c2",

        "l12"."c1",
        "l12"."c2",

        "l13"."c1",

        "l14"."c1",
        "l14"."c2",

        "l15"."c1",
        "l15"."c2",

        "l16"."c1",
        "l16"."c2",
        "l16"."c3",

        "l17"."c1",

        "l18"."c1",

        "l19"."c1",
        "l19"."c2",

        "l20"."c1",
        "l20"."c2",

        "l21"."c1",
        "l21"."c2",
        "l21"."c3",
        "l21"."c4",

        "SnowyVic"."c1",
        "SnowyVic"."c2",
        "SnowyVic"."c3"   /;


option lmap:1:1:2;
display nnn, n, nmap, ii, i, imap, ff, f, g, l, lmap, c, lcmap;
```

```
* ------------------------------------------------------------------ *
*     INPUT DATA:
* ------------------------------------------------------------------ *

PARAMETERS
*     Data input parameters:
      load(s)           NSW region benchmark load and price
      pdata(n,*)  NSW population by node data
      gdata(nnn,ii,*)   Generator data
      edata(ff,*)       Firm benchmark emissions data
      lcdata(n,*) Node location data
      tdata(l,c,n,nn,*) Transmission line data
      loc(n,*)    Location coordinates of nodes
*     Time parameters:
      time        Length of analysis period [hrs]
      segments    Number of load segments [-]
      t_seg(s)    Length of each load segment [hrs]
*     Consumer model parameters:
      load(s)           Total NSW region load [MWh_e]
      pop(n)            NSW population by node [people]
      pop_tot           Total NSW population [people]
      pop_fr(n)   Fraction of total population [-]
      d0(n,s)           Benchmark demand [MWh_e]
      p0(s)       Benchmark price [$ per MWh_e]
*     Generator model parameters:
      capf(i)           Capacity factor [-]
      eff(i)            Efficiency [%]
      eff_GJ(i)   Efficiency [MWh_e per GJ fuel]
      pf(i)       Fuel price [$ per GJ fuel]
      vc(i)       Variable generation cost [$ per MWh_e]
      em_com(i)   Combustive emissions [kg CO2 per GJ fuel]
      em_fug(i)   Fugitive emissions [kg CO2 per GJ fuel]
      mc(i)       Short-run marginal cost [$ per MWh_e]
      gcap(i)           Nominal generation capacity [MW_e]
      fcap(i)           Load factor limit [MWh_e]
      carb(i)           Carbon emissions intensity [t CO2 per MWh_e]
      ecap(f)           Emissions cap [t CO2 per yr]
*     Transmission line model parameters:
      volt(l,c)   Nominal voltage [kV]
      tcap_c(l,c) Circuit capacity [MW_e]
      x(nn,mm)    Line reactance [p.u.]
      tcap(l)           Transmission capacity [MW_e]
      ptdf(l,n)   Power transfer distribution factor (PTDF);


* Data input:
$onecho >Outputs\data.rsp
par=pdata   rng="PopData!B2..C21"         cdim=1 rdim=1
par=gdata   rng="GenData!A3..T65"         cdim=1 rdim=2
par=edata   rng="EmData!A3..B12"          cdim=1 rdim=1
par=tdata   rng="TranData!A3..F85"        cdim=1 rdim=4
par=lcdata  rng="LocData!B3..L22"         cdim=1 rdim=1
$offecho
$if not exist Outputs\data.gdx $call 'gdxxrw i=NSWData.xlsx o=Outputs\
    data.gdx trace=3 log=Outputs\data_log.log @Outputs\data.rsp'
$gdxin      Outputs\data.gdx
$loaddc     pdata gdata edata tdata lcdata
$gdxin Outputs\load.gdx
$loaddc s load p0 time t_seg
```

```
option time:0, t_seg:1;
display time, t_seg, s;


* Define load model parameters:
pop(n) = pdata(n,"Population");
pop_tot = sum(n, pop(n));
pop_fr(n) = pop(n)/pop_tot;
d0(n,s) = pop_fr(n)*load(s);
option load:1, pop:0, pop_tot:0, pop_fr:2, d0:1, p0:2;


* Define generator model parameters:
loop(imap(i,ii),
      capf(i) = sum(nnn, gdata(nnn, ii, "Capacity_Factor"));
      eff(i) = sum(nnn, gdata(nnn, ii, "Efficiency"));
      pf(i) = sum(nnn, gdata(nnn, ii, "Fuel_Cost"));
      vc(i) = sum(nnn, gdata(nnn, ii, "Variable_Costs"));
      em_com(i) = sum(nnn, gdata(nnn, ii, "Combustion_Emissions"));
      em_fug(i) = sum(nnn, gdata(nnn, ii, "Fugitive_Emissions"));
      gcap(i) = sum(nnn, gdata(nnn, ii, "Capacity"));
);

eff_GJ(i)$eff(i) = 1/eff(i)*3.6;
mc(i) = eff_GJ(i)*pf(i) + vc(i);
fcap(i) = capf(i)*gcap(i)*time;
carb(i) = eff_GJ(i)*(em_com(i) + em_fug(i))/1000;
loop(fmap(f,ff),
      ecap(f) = edata(ff, "Emissions");
);
option eff:3, eff_GJ:3, pf:2, vc:2, em_com:1, em_fug:1;
option mc:2, gcap:0, fcap:0, carb:2, ecap:3;


* Define transmission line model parameters:
loop(lmap(l,nn,mm),
      volt(l,c) = tdata(l,c,nn,mm,"Voltage");
      tcap_c(l,c) = tdata(l,c,nn,mm,"Capacity");
*     x(nn,mm) = tdata(l,nn,mm,"Reactance");
);
tcap(l) = sum(c, tcap_c(l,c));
option volt:0, tcap_c:0, tcap:0;


* Network infrastructure located outside of NSW:
gcap("iGC") = tcap("Directlink") + 1;
gcap("iSWQLD") = tcap("QNI") + 1;
gcap("iVIC") = tcap("SnowyVic") + 1;
ecap("fGC") = +INF;     ecap("fSWQLD") = +INF;  ecap("fVIC") = +INF;
capf("iGC") = 1;
capf("iSWQLD") = 1;
capf("iVIC") = 1;
fcap("iGC") = capf("iGC")*gcap("iGC")*time;
fcap("iSWQLD") = capf("iSWQLD")*gcap("iSWQLD")*time;
fcap("iVIC") = capf("iVIC")*gcap("iVIC")*time;


SETS  ib(i) Set of generators to compute boundary mc;
ib(i) = yes;
ib("i5") = no;
ib("i6") = no;
```

```
mc("iGC") = smax(ib, mc(ib));
mc("iSWQLD") =  mc("iGC");
mc("iVIC") = mc("iGC");

display time, t_seg, load, pop, pop_tot, pop_fr, d0, p0;
display eff, eff_GJ, pf, vc, em_com, em_fug, mc, gcap, fcap;
display carb, ecap, volt, tcap_c, tcap;



* ------------------------------------------------------------------ *
*     TRANSMISSION LINE DISTANCE CALCULATION:
* ------------------------------------------------------------------ *

$Ontext
Adapted from "Great Circle Distances" - GAMS Library (GREAT,SEQ=73)

The shortest distance (great circle distance) between pairs of points
is desired. First, the spheric coordinates are translated into
Cartesian coordinates. Second, the straight line distance between
points on the unit sphere are calculated. Third, the great circle
distances are computed.

The center of the earth is the origin for all coordinate systems.

Spherical coordinates:
      latitude angle    north positive
                        south negative
      longitude angle   east  positive
                        west  negative

Cartesian coordinates:  x-axis      0 N   0 E
                        y-axis      0 N   90 E
                        z-axis      90 N

For reading into gdx file from Excel, the following is used:
      N     1
      S     2
      E     3
      W     4

$Offtext


SETS        k     Cartesion coordinates
            / x-axis, y-axis, z-axis /

      co    Coordinates - data taken from Google Earth
            / lat_deg, lat_min, lat_sec, lat_dir,
              lon_deg, lon_min, lon_sec, lon_dir /;


* Define latitude coordinates:
loc(n,"lat_deg") = ifthen(lcdata(n,"Lat-Dir") eq 2,
                  -lcdata(n,"Lat-Deg"), lcdata(n,"Lat-Deg"));
loc(n,"lat_min") = ifthen(lcdata(n,"Lat-Dir") eq 2,
                  -lcdata(n,"Lat-Min"), lcdata(n,"Lat-Min"));
loc(n,"lat_sec") = ifthen(lcdata(n,"Lat-Dir") eq 2,
                  -lcdata(n,"Lat-Sec"), lcdata(n,"Lat-Sec"));

* Define longitude coordinates:
loc(n,"lon_deg") = ifthen(lcdata(n,"Lon-Dir") eq 2,
```

```
                  -lcdata(n,"Lon-Deg"), lcdata(n,"Lon-Deg"));
loc(n,"lon_min") = ifthen(lcdata(n,"Lon-Dir") eq 2,
                  -lcdata(n,"Lon-Min"), lcdata(n,"Lon-Min"));
loc(n,"lon_sec") = ifthen(lcdata(n,"Lon-Dir") eq 2,
                  -lcdata(n,"Lon-Sec"), lcdata(n,"Lon-Sec"));


SCALARS     pi    Trigonometric constant  / 3.141592653 /
            r     Radius of earth [km]    / 6378.1 /;


PARAMETERS
      lat(n)            Latitude angle [radians]
            lon(n)            Longitude angle [radians]
            uk(n,k)           Point in cartesian (unit sphere)
            useg(n,nn)  Straight line distance (unit sphere)
            udis(n,nn)  Great circle distances (unit sphere)
            dis_node(n,nn)    Great circle distance [km] - nodes
      dis_line(l) Great circle distance [km] - lines;

lat(n) = (loc(n,"lat_deg")  + loc(n,"lat_min") /60)*pi/180;
lon(n) = (loc(n,"lon_deg") + loc(n,"lon_min")/60)*pi/180;

uk(n,"x-axis") = cos(lon(n))*cos(lat(n));
uk(n,"y-axis") = sin(lon(n))*cos(lat(n));
uk(n,"z-axis") =             sin(lat(n));

useg(n,nn) = sqrt(sum(k, sqr(uk(n,k)-uk(nn,k))));
udis(n,nn) = pi;
udis(n,nn)$(useg(n,nn) lt 1.99999) = 2*arctan(useg(n,nn)/
      2/sqrt(1-sqr(useg(n,nn)/2)));

loop(lmap(l,n,nn),
      dis_node(n,nn) = r*udis(n,nn);
      dis_line(l) = r*udis(n,nn);
);

* Interconnectors between NSW and Queensland-Victoria:
dis_line("Directlink") = 59.0;

option loc:0, dis_node:1, dis_line:1;
display loc, dis_node, dis_line;



* ------------------------------------------------------------------- *
*     TRANSMISSION LINE REACTANCE CALCULATION:
* ------------------------------------------------------------------- *

$ontext
Transmission reactance assumptions are taken from:
Kundur, P.; "Power system stability and control", Table 6.1
& Table 6.2, McGraw-Hill, 1994 - ISBN 0-07-035958-X

Table 5.1 - Overhead lines:
      Nominal Voltage   [kV]  230   345   500
      Resistance [ohm per km] 0.050 0.037 0.028
      Reactance [ohm per km]  0.488 0.367 0.325
      Admittance [uS per km]  3.371 4.518 5.200

Table 5.2 - Cables (PILC):
      Nominal Voltage [kV]    115   230   500
```

```
      Resistance [ohm per km] 0.0590      0.0277      0.0128
      Reactance [ohm per km]  0.3026      0.3388      0.2454
      Admittance [uS per km]  230.4 245.6 96.5


Another source with reactance values per unit distance (Section II.D):
Zhou et al; "Approximate Model of European Interconnected System as
a Benchmark System to Study Effects of Cross-Border Trades",
IEEE Transactions on Power Systems, Vol. 20, No. 2, May 2005


The total capacitive reactance of a parallel circuit is as follows:

x_total = 1 / (sum(c, 1/x(c)));
      where c denotes a single circuit in a parallel connection
      and x(c) is the reactance of an individual circuit

$offtext

PARAMETERS
      xc_dis_ohm(l,c)   Circuit reactance [ohm per km]
      xc_ohm(l,c) Circuit reactance [ohm]
      xc_max            Maximum circuit reactance [ohm]
      xc_pu(l,c)  Circuit reactance [p.u.]
      x_pu(l)           Equivalent single line reactance [p.u.];


* Reactance values are a linear interpolation of source values:
xc_dis_ohm(l,c)$lcmap(l,c) = -0.0006*volt(l,c) + 0.6029;
* The Directlink connections are cables:
xc_dis_ohm("Directlink",c)$lcmap("Directlink",c) =
      -0.0002*volt("Directlink",c) + 0.3474;

* Multiply by line distance:
xc_ohm(l,c) = xc_dis_ohm(l,c)*dis_line(l);

* Determine the maximum circuit reactance value:
xc_max = smax((l,c),xc_ohm(l,c));

* Convert to per unit:
xc_pu(l,c) = xc_ohm(l,c)/xc_max;

* Convert parallel circuit reactances to single line reactance:
x_pu(l) = 1 / sum(c$lcmap(l,c), 1/xc_pu(l,c));

* Express line reactance in terms of nodes:
loop(lmap(l,nn,mm),
      x(nn,mm) = x_pu(l);
);

option xc_dis_ohm:4, xc_ohm:2, xc_max:2, xc_pu:4, x_pu:4, x:4;
display xc_dis_ohm, xc_ohm, xc_max, xc_pu, x_pu, x;



* -------------------------------------------------------------------- *
*     PTDF CALCULATION:
* -------------------------------------------------------------------- *

SETS  Bset  Susceptance matrix set;

Bset(n) = yes;
```

```
Bset("%ref_node%") = no;


PARAMETERS
*       Computed parameters:
        adj(nn,mm)        Adjacency matrix
        deg(nn)                 Degree matrix
        B(nn,mm)          Susceptance matrix
        X_(nn,mm)         Reactance matrix (inverse of B_)
        PTDF_(m,n,nn,mm)  Complete PTDF matrix
        PTDFs(m,nn,mm)          Slack-referenced PTDF matrix
*       Output parameter:
        ptdf(l,n)         PTDF matrix
*       Check parameters:
        chk_ptdf(n)       Check summation of ptdf values;


adj(nn,mm)$x(nn,mm) = 1/x(nn,mm);
adj(mm,nn)$adj(nn,mm) = adj(nn,mm);
deg(nn) = sum(mm, adj(nn,mm));


* Admittance matrix calculation:
B(nn,mm) = -adj(nn,mm);
B(nn,mm)$(ord(nn) eq ord(mm)) = deg(nn);
B("%ref_node%",mm) = 0; # Make matrix non-singular
B(nn,"%ref_node%") = 0;


* Invert the admittance matrix to create the susceptance matrix:
EXECUTE_UNLOAD    'Outputs\susceptance.gdx' Bset, B;
EXECUTE           'invert Outputs\susceptance.gdx Bset B Outputs\
    reactance.gdx X_';
EXECUTE_LOAD      'Outputs\reactance.gdx', X_;


* PTDF Calculation:
PTDF_(m,n,nn,mm)$x(nn,mm) = (X_(m,nn) - X_(m,mm)
      - X_(n,nn) + X_(n,mm))/x(nn,mm);
PTDFs(n,nn,mm) = PTDF_("%ref_node%",n,nn,mm);
loop((nn,mm,l)$lmap(l,nn,mm),
      ptdf(l,n) = PTDFs(n,nn,mm);
);


* Summation check:
*       Lines going out of a node assigned positive value
*       Lines going into a node assigned negative value
*       Sum of lines should be 1 for a given node
chk_ptdf(n) = sum((nn,mm)$(ord(nn) eq ord(n)), PTDFs(n,nn,mm))
            - sum((nn,mm)$(ord(mm) eq ord(n)), PTDFs(n,nn,mm));


option PTDF_:4:2:2, PTDFs:4:1:2, ptdf:4:1:1;
display PTDF_, PTDFs, ptdf, chk_ptdf;
display x, X_;


* ------------------------------------------------------------------- *
*       LOAD MODEL SETS & PARAMETERS INTO GDX FILES:
* ------------------------------------------------------------------- *
```

```
EXECUTE_UNLOAD    'Outputs\nswdata.gdx' n, z, zmap, i, f, g, l, s, lmap, time, t_seg, d0, p0, mc, gcap, fcap, carb, ecap, tcap, ptdf;
```

C.3 Load-Duration Aggregation Tool

```
$TITLE      Aggregate Load Segments Into Reduced Representative Set

$eolcom #


$if not set ref_year    $set ref_year 2010
$if not set no_seg      $set no_seg 20


SETS  yr          Year
                  / 2009, 2010 /

      ss          Load segment names in source data
                  / Segment1*Segment17520 /

      s           Aggregated data set for export to model
                  / 1*%no_seg%, "Peak" /

      as(s)       Aggregated data set
                  / 1*%no_seg% /

      per         Percentiles
                  / 10, 20, 30, 40, 50, 60, 70, 80, 90, 99 /

      asmap(ss,as)      Mapping data segments to aggregated segments
      smap(s,as)  Mapping aggregated segments to model segments;

ALIAS (ss, sss);


PARAMETERS
*     Load data:
      ldata(yr,ss,*)          Total NSW region load and price data
      tload(ss)         Total NSW region load [MW_e]
      rank(ss)          Rank order of load segment in data set
      aload(ss)         Aggregated load data [MW_e]
      pct(per)          Load percentiles
      load(s)                 Reduced benchmark data for model [MW_e]
      p(ss)             NSW regional price data [$ per MWh_e]
      p0(s)             Reduced benchmark price [$ per MWh_e]
*     Time parameters:
      time              Length of analysis period [hrs]
      no_full_seg       Number of segments - full set [-]
      t_seg_f                 Length segment - full set [hrs]
      t_seg(s)          Length segment - aggregated set [hrs]
      length                  Length segment - aggregated
      agg_seg(as)       Range for each aggregated segment
*     Error minimisation:
      res(ss)                 Aggregation residual [MW_e]
      sq_res(ss)        Squared residual
      err               Total squared residual error;


* Data input:
```

```
$onecho >Outputs\loaddata.rsp
par=ldata   rng="LoadData!A3..D17523"     cdim=1 rdim=2
$offecho
$if not exist Outputs\loaddata.gdx $call 'gdxxrw i=NSWData.xlsx o=Outputs\loaddata.gdx trace=3 log=Outputs\loaddata_log.log @Outputs\loaddata.rsp'
$gdxin      Outputs\loaddata.gdx
$loaddc     ldata

tload(ss) = ldata("%ref_year%",ss,"Demand");
p(ss) = ldata("%ref_year%",ss,"Price");
pct(per) = per.val + eps;


* Run the rank program to order the data set:
$batinclude rank tload ss rank pct


* Compute time parameters:
time = 8760;
no_full_seg = card(ss);
t_seg_f = time / card(ss);
t_seg(s) = (time - 0.5)/(card(s) - 1);
t_seg("Peak") = 0.5;
length = card(ss) / card(as); # Length of each reduced load segment
agg_seg(as) = ord(as)*length; # Range for each reduced load segment


* Assign each load segment to an aggregated load segment:
asmap(ss,as) = yes$(agg_seg(as-1)<rank(ss) and rank(ss)<=agg_seg(as));
smap(s,as) = yes$sameas(s,as);

tload(ss) = tload(ss)/1000;   # Reduce size of load parameter for solver


* Aggregation error minimisation:
VARIABLES   A_LOAD(as)  Aggregated load values [MW_e]
            OBJ         Objective function;

NONNEGATIVE VARIABLES   A_LOAD;


EQUATIONS   min_res           Aggregation error minimisation;

min_res..   OBJ =e= sum(asmap(ss,as), sqr(A_LOAD(as) - tload(ss)));


model minp  / all /;

solve minp minimizing OBJ using nlp;


* Assign parameters for export to model:
loop(smap(s,as),
      load(s) = 1000 * A_LOAD.L(as);
);
load("Peak") = 1000 * smax(ss, tload(ss));


* Rescale back to original values:
tload(ss) = tload(ss)*1000;
```

```
PARAMETERS  sumload(as)
            val(ss)
            value(as);

loop(smap(s,as),
      sumload(as) = sum(ss$asmap(ss,as), tload(ss));
      val(ss) = p(ss)*tload(ss);
      value(as) = sum(ss$asmap(ss,as), val(ss));
      p0(as(s)) = value(as)/sumload(as);
);
p0("Peak") = ldata("%ref_year%","Segment1038","Price");


display s, time, t_seg, load, p0, pct;


* Export to model:
EXECUTE_UNLOAD 'Outputs\load.gdx', s, time, t_seg, load, p0;
```