An Assessment of the Economic, Regulatory and Technical Implications of Large-Scale Solar Power Deployment

by

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B.E., Civil Engineering, University College Dublin (2006)

Submitted to the Engineering Systems Division and the Department of Electrical Engineering and Computer Science
in partial fulfillment of the requirements for the degrees of

Master of Science in Technology and Policy

and

Master of Science in Electrical Engineering and Computer Science

at the

MASSACHUSETTS INSTITUTE OF TECHNOLOGY

September 2010

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Abstract

Electricity from solar energy has many favourable attributes. Despite its current high cost relative to other technology options, a combination of cost reductions and policy support measures could lead to increasing deployment of solar power technologies.

Should this pathway occur, the unique technical and economic characteristics of photovoltaics (PV) and concentrating solar power (CSP) technology will have implications for the wider electric power system. Similarly, the characteristics of the many elements that constitute electric power systems will have implications for the efficient deployment of these technologies. This thesis attempts to assess these technical and economic implications, and derive regulatory implications that result.

A static cost-minimisation expansion model with an 8760 hour temporal resolution, adapted from the literature, was developed in order to undertake this investigation. Following analytical development of the model formulation, the model was numerically applied to a simplified representation of the ERCOT power system. This application involved assessing changes in investment, dispatch, prices and emissions across various solar power deployment scenarios. The final portion of the thesis then addressed the complexities associated with developing the necessary transmission that may accompany large-scale solar power deployment.

Findings from this work include: a) an explicit representation of the components that constitute the marginal system value of PV capacity under transmission constraints b) reasoning for why the optimal system with large scale solar power capacity includes less baseload capacity in the long term - and insights into how this may not be feasible in real systems, and c) a presentation of how solar power deployment paths diverge across capacity and energy support schemes, and across type of solar technology. In addition, it is found that: d) under perfect conditions, locational market prices will provide the adequate locational signals for 'system-efficient' deployment, provided that the solar generators 'see' the signals in their objective functions, and e) the appropriateness of transmission charges for solar generators will vary by circumstance - any charge warranted should be considered in tandem with the system pricing mechanism and any renewable support scheme in place.

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Acknowledgments

The Massachusetts Institute of Technology is a special place, and I have gained more from my experience here than I could have dared hope for upon my arrival. There are many people to acknowledge for their support in the intervening 2 years.

Of most immediate relevance to this document, I am indebted to my two thesis supervisors, Dr. Joshua Linn and Professor Ignacio Pérez-Arriaga for the advice, guidance, time, and encouragement they have provided me throughout this thesis process. I have learned an immense amount.

Particularly, I thank Joshua Linn for initially providing me with the opportunity to join the MIT Future of Solar Energy Study, while I thank Ignacio Pérez-Arriaga for supporting my dual degree petition, thus allowing this thesis to meet the requirements of a dual degree with Course 6.

I thank Professor Andrés Ramos and Dr. Luis Olmos, from whose collaboration this thesis has benefitted significantly. This thesis has also benefitted from data and insights provided by fellow students Anya Castillo, Trannon Mosher, Diana Chiyangwa, and Yuan Yao.

I thank the people at NREL for their hospitality during my visit to Colorado in June of 2009 and I thank Mr. Steve Connors for helping to arrange that visit. In particular, I thank Mr. Matt Mowers of NREL for his assistance both during the visit and in the time that has passed since.

I thank the MIT Future of Solar Energy Study, and thus the Chesonis Foundation, for financial support during my time here. It was a privilege to work with, and learn from, the various faculty involved. I also wish to thank the staff at the MIT Energy Initiative for making the 3rd floor of E19 such a pleasant working environment.

I thank Ms. Sydney Miller and Mr. Ed Ballo at TPP for all their advice and for ensuring administrative matters were always fun to sort out. On the EECS side, I thank Ms. Janet Fischer for making the administrative organisation of the dual degree proceed so smoothly.

TPP is a unique program that I am fortunate to have been a part of, and I thank Professor Dava Newman and Dr. Frank Field for providing the leadership that makes TPP what it is. In addition, I thank all the faculty who put so much time and effort into teaching such demanding, yet ultimately rewarding, graduate level courses at MIT. A particular thank you to Professor Dave Marks for his invaluable advice when I was deciding whether to accept MIT's offer (and on many occasions since).

Meeting fellow students from across the Institute has been truly inspirational, and will likely endure as the highlight of my time at MIT. I thank them all for their friendship over the past two years. Particular mention should go to fellow students in E19, TPP, the MIT Energy Club, Sidney Pacific, and the MIT Irish Association.

The support of my USA-based friends prior to my arrival and throughout my time here has been invaluable. I particularly thank Ms. Bess Pierce for her friendship and support in this regard.

I would not be submitting this thesis without the encouragement and support I have received from all of my family throughout my life to date. I would like to especially acknowledge the kindness of my Godparents Noel and Helen.

Finally, I dedicate this work to my siblings, Brian and Caoimhe, and my inspirational parents, Matt and Catherine - to whom I owe the greatest thanks.

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List of Acronymns

AB	Allocation to Beneficiaries
AC	Alternating Current
AP	Average Participations
CaISO	California Independent System Operator
CC	Combined Cycle
CO_2	Carbon Dioxide
CSP	Concentrating Solar Power
CT	Combustion Turbine
DC	Direct Current
DNI	Direct Normal Insolation
ERCOT	Electricity Reliability Council of Texas
EU	European Union
FIT	Feed-in-tariff
GHI	Global Horizontal Insolation
GW	Gigawatt
GWh	Gigawatt-hour
kW	Kilowatt
kWh	Kilowatt-hour
MIT	Massachusetts Institute of Technology
MITEI	MIT Energy Initiative
MW	Megawatt
MWh	Megawatt-hour
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
PV	Photovoltaics
ReEDS	Regional Energy Deployment System
RPM	Revolutions Per Minute
RPS	Renewable Portfolio Standard
USDOE/DOE	United States Department of Energy

Chapter 1

Introduction

1.1 Motivation

Of humankind's many technological advances of the 20th century, the National Academy of Engineering has classified Electrification as the greatest engineering achievement of the century [1]. Electricity undoubtedly has brought huge benefits to society, becoming an integral part of people's lives. As the second decade of the 21st century commences, electric power systems are potentially on the cusp of unprecedented technical change. This can be attributed to a number of factors, including; a) environmental and security externalities associated with conventional forms of electricity generation, b) the finite nature of the fossil fuels that provide the energy for the majority of current conventional generation, and c) the ongoing development and deployment of renewable energy technologies with characteristics different to those of conventional generators.

Solar power represents a subset of these renewable energy technologies, with a production profile, unlike conventional technologies, that is a function of temporal and spatial distributions. Due to the vast quantity and self-sustaining nature of the solar resource [2], and ongoing cost reductions of the associated technologies, it is reasonable to expect that solar power will contribute to the evolution of electric power systems to meet 21st century needs. Due to solar power's differing characteristics, an expansion of solar power deployment, whether by policy or market forces or both, will have implications for power systems. In addition the characteristics of the broader power system will have implications for the extent and distribution of solar power deployment.

These implications span technical, economic and regulatory fields and an understanding of these implications is crucial to informing both the array of policies affecting renewable energy and power system development, and the many investment decisions that will determine the evolution of the capital stock of electric power sectors worldwide.

As will be seen throughout this thesis, locational effects matter in this discussion, and thus ‘large-scale’ could refer to ‘large-scale’ on a local level up to ‘large-scale’ on a continent-wide level.

1.2 Thesis Research Questions

Considering the above, the underlying goal of this thesis is to gain an understanding of these implications in order to inform what an efficient path to large-scale solar power deployment may involve. This goal leads to the following set of more specific research questions:

- How do the technical characteristics of power systems, in particular transmission network effects, impact upon the long term value of remotely located solar energy generation?
- How will increasing deployments of solar power affect the optimum generation and transmission mix, under technology cost reduction scenarios and various support policies? What differences can be expected between photovoltaic and concentrating solar power deployment?
- How does pricing of transmission affect solar power deployment outcomes?

1.3 Approach

In order to address the questions of this thesis, the chosen approach has consisted of the following steps:

- How electricity from solar energy is generated was analysed from a technical and economic perspective.
- A linear cost minimisation model of a power system, adapted from the literature, and incorporating both generation and transmission expansion and operation variables, was designed, developed and applied.

- The formulation of this model, entitled Expan, was analytically studied in order to a) understand the tradeoffs that are behind the model results and b) gain insight into the underlying components of the long term marginal benefit of a solar generator in a network system.
- The Expan model was applied to a simplified version of the ERCOT (Texas) power system for a range of scenarios where large quantities of photovoltaics or concentrating solar power may be deployed - because of decreasing cost of technology, application of solar-specific Renewable Portfolio Standards, or existence of a carbon price. Insights into the questions of the thesis were gained by the comparison of patterns across results.
- In an attempt to gain further insight into these issues, the NREL ReEDS model was employed to consider outcomes using a different model structure and input parameters.
- Appropriate means to efficiently allocate network investment costs among agents were analysed. In particular, the 'Average Participations' network usage estimation methodology was applied to the findings of the Expan model by the interpretation, development and application of the associated algorithm.

1.4 Summary of Findings

The findings, as explained through the document, can be represented as follows:

- A framework for assessing the marginal value a PV (or wind) capacity under transmission constraints was developed. The covariances between the pattern of production of the PV generator with the system price and with the transmission constraint dual variables were found to be significant components.
- The framework allows explicit consideration of the tradeoff between developing poorer quality solar resources close to demand and higher quality solar resources in remote locations. In such a system the cost of transmission reduces the value of solar power - but the extent to which it does so was found to be influenced by the above mentioned covariances. The absolute effects will vary from system-to-system depending on the

nature of the underlying system and the profile of the wind and solar resources in that system.

- The framework allows the cross-effects of wind and photovoltaic power to be considered. For the ERCOT system, photovoltaics were found to slightly increase the marginal value of a unit of wind capacity.
- Under the framework of the Expan model, baseload generating capacity was found to be displaced by large-scale deployment of solar power. Use of the larger ReEDS model highlighted the relevance of what capacity is installed in base case scenarios, with solar power displacing the avoided investment. What technology is displaced by solar power deployment, directly affects the impact of the deployment on carbon emissions.
- The method of PV deployment (cost reductions or policy capacity support versus policy energy support) affects the distribution of the solar power deployment, with implications for associated transmission requirements. A similar divergence was not noted for CSP.
- Increased penetrations of solar power will lead to shifts in the shape of the price duration curve at each node, leading to reductions in wholesale electricity prices. The price duration curves associated with photovoltaic deployment and with CSP deployment differed.
- The benefits of storage to solar power deployment were illustated by the consideration of a number of CSP deployment scenarios.
- Studying the benefits of transmission lines illustrates that the benefits of transmission corridors are not confined to the associated end-generators and end-loads but users throughout the network to varying degrees. The example results presented indicate that the findings are non-intuitive.
- The circumstances where it may, or may not, be appropriate to allocate transmission charges to solar power generators were identified.
- The inefficiency of not including locational signals in the objective functions of renewable energy generators was explicitly shown.

1.5 Structure of Thesis

The structure of the thesis is as follows: Chapter 2 provides context to the issues addressed, Chapter 3 discusses previous work in the literature relevant to this multi-disciplinary thesis, and Chapter 4 concludes the introductory chapters by discussing the thesis modelling methodology. As for the chapters based on analytical and numerical analysis: Chapter 5 presents the Expan model structure, along with associated analytical development, Chapter 6 presents results of the application of this model to the ERCOT system, Chapter 7 discusses the NREL ReEDS model, while Chapter 8 considers one issue of importance in depth - transmission of solar power.

The thesis concludes with the findings and recommendations of Chapter 9, followed by a discussion of future work (Chapter 10), the Bibliography and Appendices.

Chapter 2

Context

In order to provide context for this thesis document, this chapter outlines the technical, economic, and regulatory characteristics of both generation of electricity from solar energy and the electric power sector in general. In particular, the core elements that differentiate solar electricity generation from traditional modes of electricity generation are discussed, focussing on the temporal and spatial resolution of the solar resource.

2.1 Electric Power Systems

Many comprehensive references exist relating to the broad array of technical, economic and policy issues relevant to the huge industrial structures that are modern electric power systems.[1]. This section thus only aims to provide a brief overview of the primary points relevant to this thesis document.

2.1.1 Technologies

Generation

Practically all of the world's electricity is currently generated by synchronous machines. To generate the required voltage to drive current through the circuits, transformers, and resistive and inductive loads that constitute a power system, the rotor component of these machines is rotated by means of energy provided by a prime mover resource. The source of this energy has traditionally come from the combustion of fossil fuels, the extraction of

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[1] Examples include [3],[4],[5].

the potential energy of water in a reservoir, nuclear fission and more recently, from wind energy and thermal energy collected from the sun. As will be discussed later, photovoltaics are an alternate means of electricity generation.

Power systems have evolved as Alternating Current systems, with the ability to increase and decrease voltages with transformers a reason for this evolution. Thus the systems are driven by a sinusoidal waveform of 50 to 60 cycles per second, depending on the region of the world, requiring a 2-pole generator in a 60Hz system to rotate at 3600 RPM or a 4 pole generator to rotate at 1800 RPM.

A relevant point about the current paradigm of electricity generation is that it is largely controllable and dispatchable in line with system requirements, subject to technical and economic ramping constraints of certain technologies.

Transmission and Distribution

Infrastructure is required to connect the electricity generated to the loads on the system. This infrastructure can be categorised as transmission and distribution. In general, transmission refers to the high-voltage 3 phase lines that connect large geographic areas whereas distribution refers to local networks that connect homes and businesses with a transmission substation via medium or low voltage and possibly on a 1 phase basis. The distinction between the two categories can be somewhat blurred at medium voltages. Traditionally, generators connect directly to transmission grids and not distribution grids.

Operational and Reliability Considerations

Supply must match demand each instant in the operation of a power system. Considering that users of the power system can freely switch on and off lights, appliances and industrial machinery, operational strategies have been designed to provide a quality electricity service under these conditions. The first step is the forecasting of the aggregate demand on the network, a practice well-honed by experience, to dispatch generation economically with the expected demand. This is followed by a system of primary, secondary, and tertiary reserves, differentiated by timescale - that require generators to increase and decrease output in response to mismatches on the system between generation and demand.

In addition, faults can occur on systems, and components can fail. Thus there are numerous security constraints that design redundancy into the system in order to prevent system collapse in the event of a component failure. These criteria have largely been developed for traditional systems with large quantities of conventional generation.

2.1.2 Economics

It is the imperative of a power system to provide electrical energy in line with market demand and typically, governmental objectives also. To do so in an economically efficient manner appears to be a reasonable paradigm in organising behaviour to meet this imperative. How this translates into modern power systems depends on the organisational structure of a particular system, which will be discussed in the next section. But the main economic decisions that must be made by the market or by a traditional utility can be divided by timescales -long term, medium term and short term.

Decisions in the long term can relate to a timescale of approximately 3 to 30 years into the future. Such long term planning is required due to the long economic lifetimes of generation and transmission assets within the power sector, and thus these long term economic decisions generally relate to investments. Decisions in the medium term can relate to a timescale of 6 months in advance to a number of years in advance. Decisions on this timescale can relate to fuel supply contracts, power purchase agreements, maintenance programs etc. Decisions in the short term generally are in the timescale from hours to weeks into the future and typically relate to the optimal dispatch of technologies in a given hour to the optimal dispatch for the next day to the hydro management plans for the next number of weeks.

2.1.3 Policies / Regulatory Structure

Traditionally, all the technical and economic activities of a given power system were managed by a centralised utility within a certain geographic scope (with the possibility of transmission between neighbouring utilities). In the 1980s, and through to today, these activities have been de-bundled around the world with the formation of electricity markets for generators, and with transmission and distribution activities remaining regulated monopolies. The overall system is then overseen operationally by one or a combination of entities from the following list: Independent System Operator (ISOs), Market Operators (MOs), and Transmission System Operators (TSOs). Of course design details of each market vary by location. The move from centralised decision making to decentralised decision making by market agents is a theme that will be of relevance throughout this document in the context of discussing the implications of solar power for electric power systems.

2.2 Electricity from Solar Energy

2.2.1 Technologies

There are two primary categories of technologies to generate electricity from sunlight; a) Photovoltaics (PV) and b) Concentrating Solar Power (CSP). How each of these two classes of technology generates electricity is described in the following paragraphs.[2]

Photovoltaics

The harnessing of the sun's energy to generate electricity using photovoltaic panels relies on a principle known as the photovoltaic effect, first identified by Becquerel in 1839, when he noticed that certain materials would produce a small amount of current when exposed to light. It was the mid 20th century by the time it was understood how to harness the photovoltaic effect to produce usable electricity, with the creation of the first operating photovoltaic cell by Bell Laboratories.

A precise explanation of the physics of the solar cell is provided by [12]. In this section the main principles of how photovoltaic cells generate electricity are outlined, with attention paid to points of particular interest to the broad questions of this thesis.

As a brief summation, a photovoltaic cell is composed of two semiconductors, a p-type semiconductor, and an n-type semiconductor, joined together to form a p-n junction. The material primarily used to create these semiconductors, silicon, is a very common material, albeit in a much purified form from its natural state. When the P-N junction is exposed to light, photons in the incoming solar radiation provide the energy to electrons to enable movement from the valence to the conduction band. The charge separation effect of the P-N junction then allows the free electrons to flow around any external circuit connected to the cell, creating a current flow. This current flow can then be harnessed to do useful things. The characteristics of the power produced by this process are discussed in Section 2.2.4.

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[2] This section draws on the reading of a variety of references including [6], [7], [8], [9], [10] and [11].

Types of PV Technologies

The different types of PV technologies are differentiated here by category - a) semiconductor material and configuration, b) light collection mechanism, and c) application.

Differentiating by cell material and configuration, the range of semiconductor materials and configurations include: thin-film silicon solar cells, amorphous silicon-based solar cells, CU(InGa)Se_2 solar cells, GaInP/GaAs multijunction solar cells, cadmium telluride solar cells, and dye-sensitised solar cells.

Differentiating by light collection mechanisms, photovoltaic modules (formed from the connection of a range of cells) can be placed in a fixed position at a chosen angle, or to increase the quantity of incoming solar radiation striking the cell, placed on a single or dual axis tracker. Another means of increasing the quantity of sunlight collected is by means of 'concentrating photovoltaics', where sunlight is focussed onto the cell by mirrors.

Photovoltaic cells are used for a wide range of applications from spaceships to rooftops to 'utility-scale' power plants. Different grid connected applications have different impacts.

All of these different options have their own particular properties but for the level of resolution of the modelling in this thesis, a differentiation is not made amongst different types of photovoltaic technologies. The modelling of solar power in this thesis is described in Section 4.2.2.

Concentrating Solar Power

Concentrating solar power technologies are a different means of generating electricity than photovoltaics. The CSP electricity generation process can be summarised as follows: i) sunlight is focussed using mirrors onto a common point, ii) at this point a fluid is heated to high temperatures by the concentrated solar energy, iii) the heated fluid is then transferred through a heat exchanger to create steam, iv) the steam is used to create a mechanical torque as per classical thermal cycles such as the Rankine cycle, v) the mechanical torque is then used to rotate the rotor and create the relative fluxes to induce a voltage as per well understood electric machine theory.

Dissimilarly to photovoltaics, only the Direct Normal Insolation (DNI) component of global insolation can be utilised in concentrating solar power plants. This is because DNI, coming in straight parallel lines from the sun, can be accurately directed by the reflector onto the heat collector. In contrast, the diffuse component of solar radiation has by definition been previously reflected and thus could be approaching the reflector from any number of angles, and thus in turn can be reflected in any number of angles, with only a small probability of being reflected onto the desired focal point.

Types of CSP Technologies

There are three main approaches to concentrate sunlight onto a heat collection area: Linear Concentrator Systems, Dish Systems, and Power Tower Systems. CSP systems also have the capability to thermally store the heated fluid in order to store the energy for conversion to electricity when it may be more financially attractive to do so.

2.2.2 Economics

The economics of solar electricity generation by both photovoltaics and concentrating solar power are dominated by the following characteristics - high upfront capital costs, low operation and maintenance costs, a zero variable cost of production, and for photovoltaics, the less-dispatchable / less-controllable nature of the technology.

Table 2.1[3] shows the capital and operating costs of different generation capacity investment options.

While this table allows comparison between the relative fixed and variable costs of each technology, a full valid comparison cannot be made here between the technology options. This stems from the fact that a number of important factors vary by technology - in particular, hours of production per year and economic life. The 'levelised cost of electricity' (LCOE) is a metric commonly used to incorporate these factors.[4] An LCOE comparison is not included here as the LCOE of a renewable generator varies considerably by area depending on the quality of the renewable resource in that area. The main point as regards this section however is that, at current costs, solar power is an expensive option for electricity capacity investment in most areas.

Finally, another important component to the economics of a solar energy project is the level and distribution of local electricity prices. Depending on the type of a photovoltaic

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[3] The numbers above come from [13] with the exception of wind power and solar power costs which come from the NREL ReEDS model (as used in Chapter 7). The NREL numbers are more favourable toward wind and solar power than the EIA numbers from [13]. Note that the CSP number includes a large collector area and 6 hours of thermal storage.

[4] For development and examples of application of the metric, see [14].

Table 2.1: Costs of Electricity Generation

Technology	Overnight Capital Costs $\$/kW$	Annual Fixed Operation Costs $\$/kW$	Variable Cost of Production[5] $\$/MWh$
Coal	2223	28.15	23
Gas[6]	968	11.96	41.5
Nuclear	3820	92.04	7
Wind	1740	30.98	0
Solar Photovoltaic	2580	11.94	0
Concentrating Solar Thermal Power	6220	43.86	0

plant, the relevant metric could be the local wholesale electricity price or the local retail price.

Finally, CSP facilities appear naturally to be a centralised generation technology with strong economies of scale present in their design, installation and operation costs. PV has traditionally been considered a distributed generation technology, with limited economies of scale, as the amount of equipment and area required are directly proportional to energy output [9]. However, this appears to have been counteracted in recent years with the construction of a large number of MW scale plants. Plants at this scale undoubtedly have economies of scale benefits for costs such as permitting, administration, and labour. This trend can be represented by noting that 12 photovoltaic plants greater than 30MW in capacity have been constructed since the start of 2008 [15], and that two plants in California have a planned installed capacity of 550MW and 250MW respectively [16].

2.2.3 Policy

As may be apparent from the preceding discussion, and for reasons that are expanded upon in Section 2.3 below, solar power has many attractive attributes to policy-makers. Considering this, and the high costs outlined in Table 2.1, much of solar energy development to date has been policy driven. While noting that many possible variants in design and implementation exist, policies that have been implemented in different jurisdictions to support solar energy development include:

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[5] Assuming heatrates from the same data source.

[6] Gas here represents gas combined-cycle. Gas combustion turbines have lower capital costs and higher variable costs.

- *Research and Development Support:* To reduce the relative cost of still-developing solar power technology in order to boost its market competitiveness, a central component of solar energy support policies must be research and development. Due to the nature of research, the benefits of the research often accrue to those outside whom the costs directly occur, thus justifying a role for government in providing this service. Research & Development for solar energy spans from funding basic research on solar energy technologies at universities and at public and private laboratories to supporting companies at the initial stage of commercialising a technology, to developing demonstration projects to foster best practice and dissemination of knowledge.

- *Feed-in-tariffs:* The implementation of feed-in-tariffs is a market stimulation method where the government sets the price rate that producers of renewable electricity receive. Typically, there is a tiered pricing structure with a different price level set by technology. This price (per kWh) is guaranteed to producers for a significant period of time, e.g. to the order of 20 years. There is an incentive for the profit-maximising solar energy producer to reduce costs as much as possible (and install solar capacity in the best locations) in order to maximise the difference between the feed-in-tariff received and the cost per kWh. An alternate scheme involves the payment of a fixed premium above the energy market price for each unit produced. Feed-in-tariffs are popular throughout the European Union, gaining most attention for their first implementation in Germany, and subsequently in Spain. More recent feed-in-tariff programs now in place are in high solar insolation locations such as Italy, Greece and France.

- *Solar-specific Renewable Portfolio Standards:* The setting of Renewable Portfolio Standards (RPS) is a policy in which a minimum amount of supplied electricity is mandated by legislation to come from renewable energy sources. RPS standards vary in their implementation from authority to authority, however the general form is as follows: - the regional or national government specifies that electricity from sources classified as renewable provide a specified portion of electricity generated by a specified year in their jurisdiction. RPS policies have been popular with states throughout the United States, and a national RPS was included in the energy legislation passed by the U.S. House of Representatives in June of 2009 (this bill has not subsequently advanced through the senate).

Solar-specific RPS policies have been implemented where a portion of supplied electricity is specifically required to come from solar electricity, termed a carve-out, or alternatively, a multiplier is applied to electricity produced from solar energy under the RPS scheme (where 1 MWh of solar energy counts as (1τ) MWh, with $\tau > 1$).

- *Tax Credits:* Tax credits come in two primary forms - investment tax credits and production tax credits. Investment tax credits allow renewable energy developers to offset a certain percentage of their investment in solar systems from their tax bill. Production tax credits allow renewable energy developers to earn a certain tax credit per kWh produced for the first X years of operation of the system.

  In addition, policies in different regions of the world have included rebates and direct subsidies on capital investment to installers of solar energy generating capacity.

In addition, solar energy development is impacted by broader economy and power system policies also, namely:

- *A Carbon Price:* Policies to address the broader issue of climate change have been implemented, or are in the legislative process, throughout the developed world. These policies vary from market based carbon pricing proposals such as 'Cap & Trade' or a carbon tax through to 'command & control' policies (which may include RPS measures). In the EU, a 'cap & trade' scheme is currently in place. A price on carbon will have a positive impact upon the cost of solar electricity relative to other sources. As deploying solar energy technology in many cases will be more expensive than other carbon emission reducing measures, in the short-term this positive effect may be limited, however a price on carbon is likely to provide a suitable long term signal to the value of solar electricity in a carbon constrained world.

- *Power System Operating Rules:* How electricity from solar energy is treated under the regulations, standards and grid code of a power system can influence its deployment. Considering the particular characteristics of solar electricity generation, rules that apply to conventional generation may not be appropriate for solar electricity generation - examples include penalties for deviating from market bids, the duration of the window between bid and dispatch, assessment burdens for connecting to transmission and distribution systems, and capacity credit evaluation measures.

A policy of this category that can be favourable to solar (and wind) power are priority dispatch orders that require renewable generation to be accepted at all times, regardless of whether it is the economically efficient thing to do or not.

- *Transmission Policy:* An area that is discussed in detail later in this thesis (Chapter 8) is access to, and pricing of, transmission in a market environment. This is of particular relevance to locationally constrained generation technologies such as wind and solar power.

2.2.4 Solar Electricity Characteristics

This section describes the power output from both PV and CSP generating technologies, outlines the environmental impact of the technologies and assesses the time-varying characteristics of their output.

Power Output from a Photovoltaic Cell

At a given temperature and level of solar radiation, taking the voltage that can be measured across the open circuit terminals of the solar cell, V_{oc}, and current that can be measured by short circuiting the terminals, I_{sc}, the maximum theoretical power of the solar cell, P_{the}, can be calculated as follows:

$$P_{the} = I_{SC}.V_{OC} \tag{2.1}$$

P_{max} is defined by the greatest possible product of V and I at any point and is defined as follows:

$$P_{max} = I_{mp}.V_{mp} \tag{2.2}$$

Where the combination of (I_{mp}, V_{mp}) represents the MPP (maximum power point) of the cell for the given conditions. Figure 2-1 graphically represents the above relationships.

Figure 2-1 shows a relatively constant current output from the cell for a range of voltages across the cell. It is thus clear why a photovoltaic cell is typically modelled as a current source. An equivalent electrical circuit for a solar photovoltaic cell can thus be represented as in Figure 2-2. The terminology of Figure 2-2 is as follows:

- I_L = Light-Generated Current

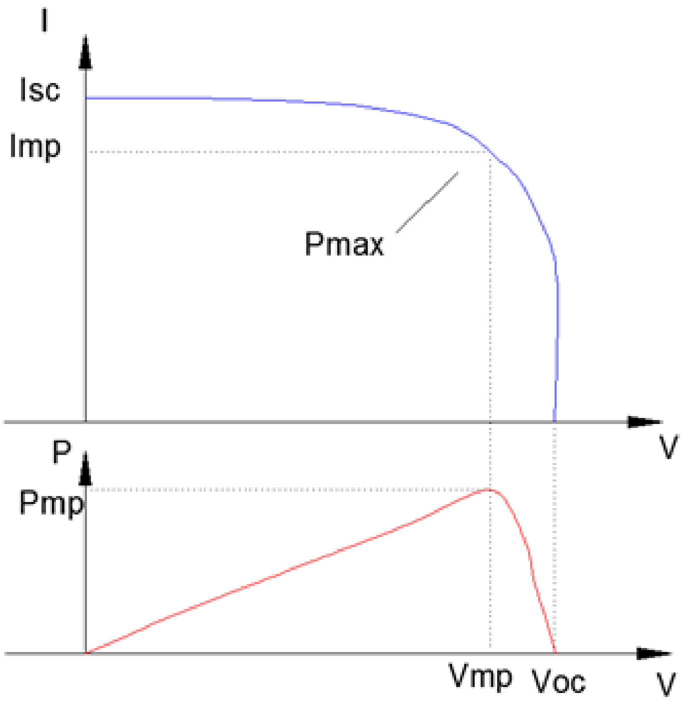

Figure 2-1: Schematic Representation of Typical P-V, I-V Relationships for a Photovoltaic Cell

- I_d = Current through the Diode - a function of the diode's saturation current, electron charge, the Boltzmann constant, temperature and a curve fitting constant. The diode component of the PV cell model above is included to model the asymmetry that arises due to the charge separation process at the P-N junction.
- I = Current at the Output Terminals
- V = Voltage at the Output Terminals
- R_s = Series Resistance that represents internal resistance to current flow - depending on the P-N junction depth, impurities and contact resistance
- R_{sh} = Shunt Resistance is inversely related to leakage current to ground, and can be typically ignored for most applications of the circuit model.

Relationship to Insolation and Temperature

In addition, there are two further noteworthy factors to mention in relation to the photovoltaic cells P-V and I-V characteristics; a) how the cell's characteristics change with

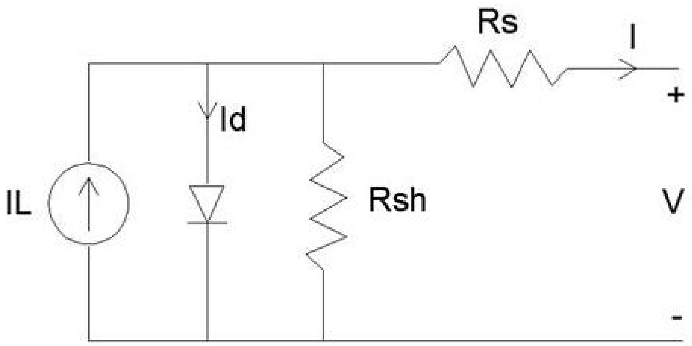

Figure 2-2: Equivalent Electric Circuit of a Photovoltaic Cell
Adapted from [10]

incoming solar radiation (insolation), and b) how the cell's characteristics change with temperature. For changes in insolation, I_{mp} changes linearly while the voltage, V_{mp}, holds relatively constant, with the general trend being that power produced is generally directly proportional to the level of insolation. For changes in temperature, both I_{mp} and V_{mp} vary with the general trend being the power produced by the cell increases as the temperature decreases(for a given level of solar radiation).

As described above, photovoltaic cells produce direct current at low voltages. To be useful to run the electrical devices we are all familiar with, or to provide power to the AC power grid, this electricity typically needs to be converted to alternating current. This is the inverter's role. Modern inverters are based on power electronics and in addition to converting DC to AC can provide additional services to the grid. Examples of such services include allowing connection at a phase angle that is most beneficial to the local system and the correction of deviations in the sinusoidal wave of the local system.

Power Output of CSP

The equivalent electric circuit of a synchronous machine is as shown in Figure 2-3. Note that it is in this manner that the vast majority of the world's electricity is generated. The difference in the case of CSP is that the energy that provides the torque to drive the rotor component of the electric generator comes from the sun as opposed to fossil fuel combustion, nuclear fission, or water gravitational difference.

Different relationships then exist between power output and both insolation and temperature for CSP compared to PV. As CSP is driven by a thermal cycle, electricity production

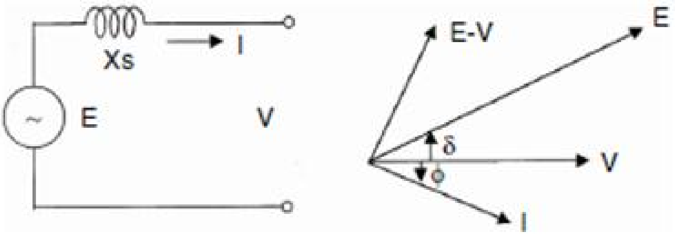

Figure 2-3: Equivalent Electric Circuit and Phasor Diagram for a Synchronous Machine
Adapted from [10]

per unit electricity generating capacity is a non-linear function of incoming solar radiation, with the function largely depending on the field collector area, the quantity of thermal storage, and turbine capacity. The main points to note are: a) the greater the magnitude of incoming solar radiation, the greater the energy collected to drive the steam cycle, and b) the greater the temperature, the greater the power produced (as the power production thermodynamic cycle is driven by temperature difference).

Time-Varying Characteristics of Photovoltaic Electricity

Previous discussion has focussed on the generation of solar electricity under a static framework - given a certain level of insolation how the solar technology generates electricity. Of concern to those managing dispatch on a power system however is how the magnitude of the electricity generated varies over time. The traditional paradigm has been to dispatch conventional thermal generation in accordance with varying demand - well characterised demand which varied on the basis of predictable cyclical daily and seasonal patterns. The entrance of zero variable cost wind and solar photovoltaics onto the system entails that the conventional generation is dispatched in accordance with demand less the time-varying renewable energy production.

Here we consider these time-varying characteristics of photovoltaic electricity under two classifications; a) variability and b) uncertainty.

Variability: Variability here is defined as how the power production varies over the hours of the year. The variability of the underlying solar resource is the primary factor of the PV plant's production variability. One way of presenting the nature of the variability of the solar resource over the year is the 'insolation duration curve' of Figure 2-4. Figure 2-5 extracts a sample 48 chronological hours from the same dataset, showing how the chronology

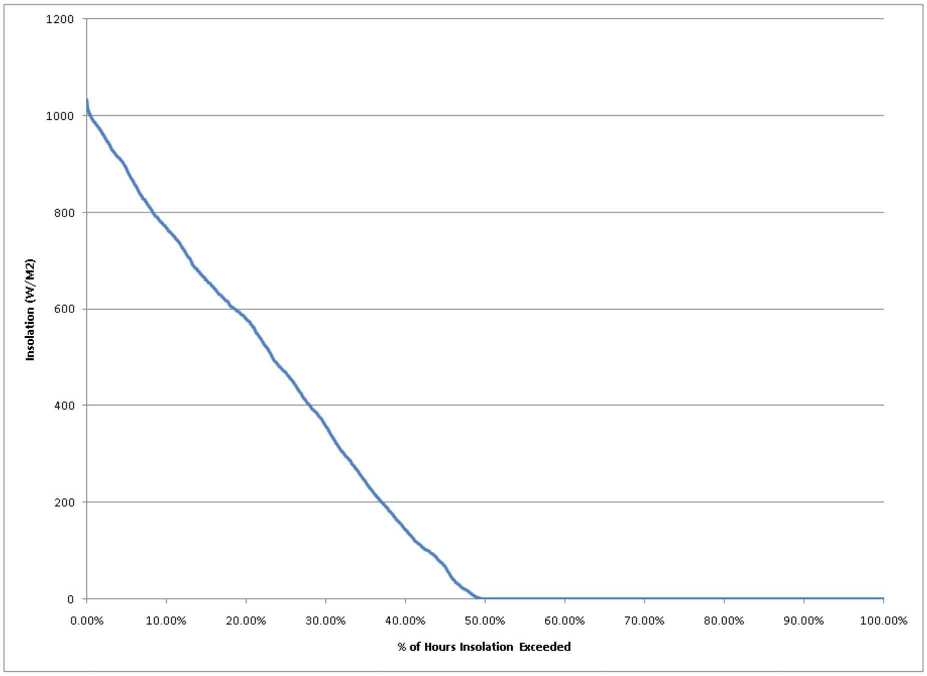

Figure 2-4: Global Insolation Duration Curve for McCamey, Texas
Hourly data from 1998

of the solar profile is important, due to its potential variability from day to day. While this data is for one location for one year, it does provide an indication of the nature of the solar resource in an area with good solar resources at a southern latitude location in the United States.

Consolidating this insolation duration curve, Figure 2-6[7] displays the duration curve of the actual power output of a PV system for the year 2005 at Florida Gulf Coast University.

It is apparent from these figures that very large-scale solar power deployment will require accompanying technologies if electricity demand is to be satisfied - for example, for 50% of the hours of the year a PV plant will not produce any electricity.

This characterisation relates to hourly and quarter-hourly variability. Variability of solar insolation at shorter timescales (e.g. minute and sub-minute) is also an important consideration. Limited work has been undertaken on the extent of short-term variability but studies have shown that geographic diversity reduces the most extreme ramping cases [17]. [17] also highlight the need for more high-resolution data to characterise solar variability to a greater extent.

Uncertainty: With a given quantity of installed capacity, variability in output can be

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[7] Data kindly provided by Mr. William Wilson of the Florida Solar Energy Center.

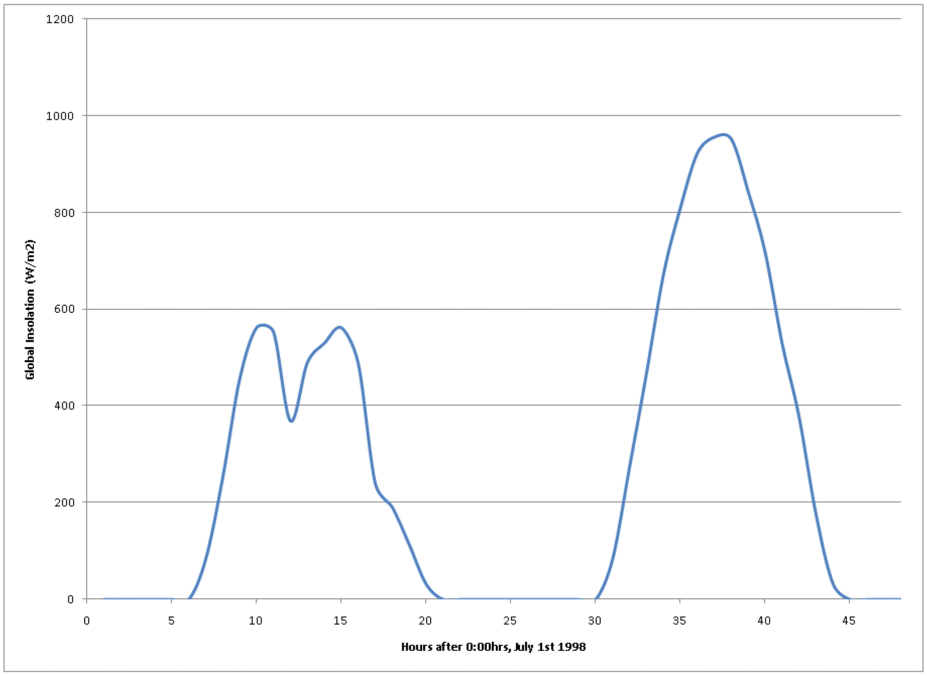

Figure 2-5: Extraction of 48 Sample Chronological Hours from Data of Figure 2-4

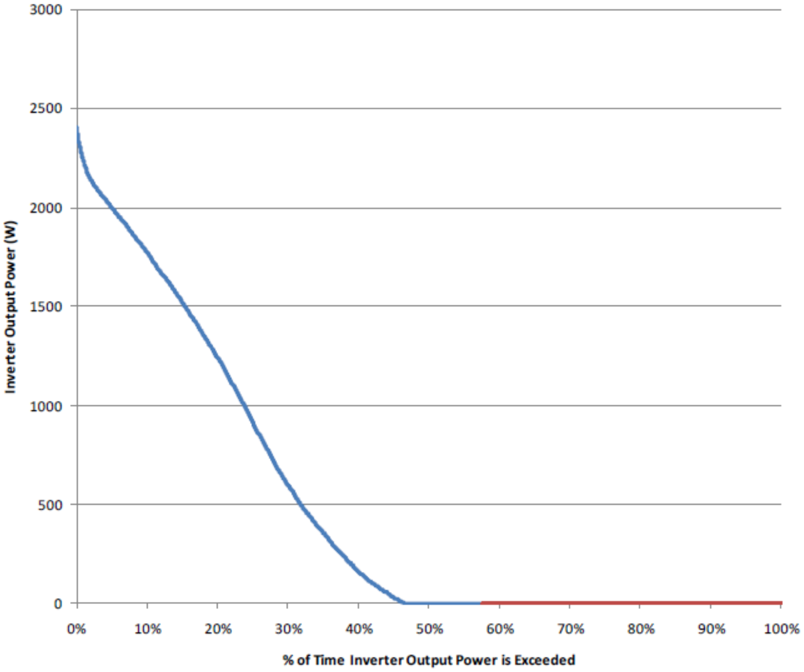

Figure 2-6: 15-Minute 2005 Inverter Power Output for PV system at Florida Gulf Coast University

adjusted for in system operations if the variability of production can be perfectly predicted. However similarly to how weather cannot be perfectly predicted, PV production has some degree of forecast error. This level of forecast error is a function of the climate of a particular area along with the amount of time before the predicted hour. Also predicting aggregate solar output for a region is subject to less error than predicting the output of each particular plant. [18] and [19] quantify the magnitude of forecast errors across different circumstances while [20] provides a comprehensive overview of the forecasting of solar (and wind) power.

Time-Varying Characteristics of Concentrating Solar Power Electricity

While a cloudy day will entail less collected solar energy to drive a steam cycle, the thermal and mechanical inertia inherent in a CSP plant ensures power output will not be as variable over the course of a day as is the case for photovoltaics [21]. Similarly, and for the same reasons CSP power output is not as uncertain as, and more predictable than, PV output.

Environmental Impact

Photovoltaics: As may be apparent when considering the above information, once a photovoltaic plant is in place it has an extremely low impact on the environment, with zero emissions of any kind, and zero requirements for fuel collection and delivery. For those who choose to wash solar panels to maximise performance some water is used.

Producing a finished, operating solar panel from raw earth materials however does require a significant labour, capital and energy input, with associated environmental impacts. It has been shown that the energy payback period for a solar panel can take place in a number of years, depending on the manufacturing process and the incoming solar radiation profile of the location.[8] The production process also involves carbon emissions, however these have been found to be offset many times by the carbon-emitting production displaced by the photovoltaic generation over its lifetime [23].

Additional environmental impacts of photovoltaics include those associated with land use and the lifecycle aspects of some chemicals that photovoltaic cells can contain.

Concentrating Solar Power:

Similarly to photovoltaics the energy produced by a CSP plant offsets the energy required

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[8] For example [22] finds an energy payback time of 1 to 2.7 years across a range of Southern European locations.

Table 2.2: PV and CSP Generation Characteristics Compared

	Photovoltaics	**Concentrating Solar Power**
Equivalent electric circuit representation	Current source	Voltage source
Distributed / Centralised generation	Distributed, also recent trend toward centralised	Large scale centralised
Fuel source	Global irradiation	Direct normal irradiation
Effect of temperature on performance under a given solar irradiance	The cooler the better	The hotter the better (to drive thermal cycle)
Storage	No inherent storage	Thermal inertia present plus additional thermal storage possible
Mechanical inertia	No inertia	Inertia (synchronous to grid)
Power quality	Inverter can improve/ disimprove power quality	Similar to conventional generators
Financing	Modular nature can ease financing process	Advantage of economies of scale can make financing challenging
Environmental impact (primary)	No emissions, some impact in manufacturing	No emissions, water requirements may be a constraint

to manufacture and construct the plant. [24] finds an energy payback time of 1-2 years for a number of studied plants in Spain.

An environmental impact of CSP production is water use, with the greatest water use coming from cooling requirements. As CSP plants are best suited to areas of high insolation, often desert or desert-like regions, this may be a constraint on CSP deployment. Air cooling can reduce the cooling requirements of a CSP plant by 97% but leads to increased costs in order to install and power the associated fans, in addition to reducing the performance of the steam cycle itself [25].

PV and CSP Characteristics Summarised

Finally, Table 2.2 summarises the characteristics of photovoltaic and concentrating solar power technology presented in this chapter of the thesis.

2.3 Why Consider the Implications of Large-Scale Solar Power Deployment?

Considering the cost of solar power relative to other technologies displayed above, and the degree of extra complication it brings to the power system, the question might be asked: is there any relevance to understanding the possible implications of large quantities of solar electricity on the power system? A number of reasons are offered below as to why understanding this topic could become increasingly relevant, commencing with commonly cited justifications for renewable energies.

2.3.1 Justifications for Renewable Energy Deployment

Environmental Externalities

Climate change is now widely recognised to be a major challenge facing human kind. Climate change has been attributed to anthropogenic-sourced greenhouse gas emissions [26]. Approximately 55% [26] of the positive radiation forcing of greenhouse gases can be attributed to carbon dioxide.[9] Carbon dioxide emitting 'conventional thermal' electricity generators provide the majority of society's electricity with some 66.3% of world supply and 70.85% of US supply in 2006 [29]. In contrast, solar power provides a carbon-free way of generating electricity. The benefits of solar electricity in particular in terms of climate change can be seen in [30], where solar photovoltaic capacity is prescribed as one of the 15 'wedges' that can contribute to humankind meeting necessary carbon reductions by mid century. Thus concern about climate change is a potential reason why large-scale solar power deployment may occur.

In addition to climate change, there are a number of additional environmental externalities associated with conventional power generation that are not associated with solar electricity. Fossil fuel burning facilities also emit particles with more direct adverse effects such as SO_2 and NOX. Other examples include scarring of natural landscapes by coal mining, the risk of ecological disaster created by drilling for natural gas, the extremely long-term waste by-products created by nuclear power or the adverse environmental impact associated with the creating of reservoirs for hydro power use.

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[9] Further information and discussion relating to climate change are available at [27] and [28].

Security Externalities

Energy independence and abstraction from volatility and uncertainty in supply of fossil fuels are an important component of energy policy in western nations.

Solar power provides a means for countries to generate electricity without the uncertainties and geopolitical implications of being dependant on fuel from other parts of the world, thus providing the potential to offset what represents a security externality associated with some classes of generation. Perhaps the most striking example in the electricity sector is the high dependence of the European Union on natural gas from Russia.

A point that could fit under a number of categories is that energy from the sun is infinite relative to the finite quantities of conventional generation fuels on the earth. If the scarcity rent of the finite nature of fossil fuels was not included in the fuel price, then their finite nature would represent an additional security externality to conventional electricity generation.

Green Economy / Rural Development

A commonly cited reason to support renewable energy development is of the potential to create new industries and associated job growth.[10]. In addition, renewable energy support policies can often fit within broader government rural development objectives, providing the potential to bring investment and tax revenues to remote locations. Areas which stand to benefit are thus likely to send representatives to capital cities with renewable energy support measures on their agenda.

2.3.2 Why Solar Power?

The possible reasons outlined above why solar power could become a greater part of the power system could all also be applied to other sources of renewable energy. Considering the lower cost and more advanced state of maturity for wind technology for example, it is valid to ask why focus on solar energy. There are numerous reasons:

- In some areas of the world, solar energy is the greatest resource, and thus will be the focus of any renewable energy investment. Additionally, the solar resource is far greater than the wind resource worldwide [2].

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[10] For sample arguments, see [31],[32].

- The implications of solar power deployment have been less studied than the implications of wind power deployment.

- Solar power has different characteristics from those of wind power - with a different resource variability profile and a wider spectrum of technologies to convert the resource to electrical energy.

- As [33] states, the cost of PV is decreasing and there are ambitious deployment targets by governments throughout the world - for example, the DOE solar program goals. This has been matched with a large growth in solar power deployment in some areas of the world.

- If a large scale transformation of the world's electricity systems are to occur in this century, it is very unlikely that this will occur with one technology solely, but will occur with an array of solutions working together cohesively, of which solar power has the potential to play a part.

- Numerous plans have proposed large-scale solar power development [34], [35], [36]. It is useful to think about some of the implications of such plans in the context of the real, functioning power systems that exist today.

There is no certainty that large-scale solar power deployment will occur however reasons exist, as expressed in this section, why such a development may. If it does occur, it will not occur in a vacuum - transmission infrastructure will be required, electrical energy will be in demand when the sun is not shining, power quality will need to be maintained, other forms of electricity generation will be displaced, and regulatory instruments may help or hinder an efficient transformation. In addition, it is likely that large scale solar power development will occur in world where wind power is also a major component of power systems - potentially leading to interesting interactions between these technologies.

This thesis, at a high level, thus attempts to assess the implications of these issues. This assessment can then be used as a framework for analysing the system-specific implications of large-scale solar power deployment across a range of timescales.

2.4 Chapter Summary

The goal of this chapter has been to provide a context for the remainder of this thesis by providing and disseminating background information on electric power systems and on the relevant technologies, policies and economics of solar power. The unique characteristics of solar power were outlined, why solar power may play an increasingly important role in future power systems was discussed, and reasons were presented why the study of the implications of solar power deployment is an interesting and relevant topic.

Chapter 3

Previous Work

This chapter briefly outlines previously undertaken works that address the multi-disciplinary issues that are the focus of this thesis. Much of the literature in relation to the interactions between renewable energies and power systems focuses on wind power.[1] Due to a number of similar characteristics between wind and solar power, portions of this literature are relevant here.

In line with the title of this thesis, the discussion below is broadly categorised into three boxes: a) technical implications, b) economic implications and c) regulatory implications. At the core of this thesis is the assertion that these implications are inter-related, and this will be reflected in the discussion below.

Finally, a general distinction can be made in the literature between studies that are system-specific, i.e. have been prepared to assess the impact of renewable generation on a particular system, and those that contain more general findings. This delineation will be noted where relevant.

3.1 Technical Implications

The coarsest technical implication of large-scale wind or solar power deployment for a power system is the necessity for significant transmission investment beyond basic grid-connection requirements. Findings to this effect for U.S. systems include [38], [39] and [40], whilst European examples include [41] and [35]. Large-scale transmission of solar electricity is focussed upon in Chapter 8.

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[1] The Utility Wind Integration Group Database of Wind Studies contains many useful references [37].

For finer, but very relevant technical implications, a distinction can be made between solar energy converted to electrical energy using photovoltaic technology or concentrating solar power technology. Due to PV's unique characteristics from a power systems perspective the focus of the literature relates to photovoltaics.

The National Renewable Energy Laboratory (NREL) undertook a Renewable Systems Interconnection study with the goal of outlining the technical and analytical challenges that may need to be addressed in order to enable large quantities of distributed renewable energy technologies to enter the power system smoothly. As part of the broader RSI study, [42] outlines a number of technical implications of high penetration levels of photovoltaics on the grid. Findings include a reduction in system inertia and frequency regulation capabilities as conventional generation is ramped down, operation of thermal units in a less efficient manner (more cycling of production), and again due to the advent of variable, less-controllable generation, risks to the dynamic stability of the system.

An issue that is also highlighted by the study is that the current requirement[2] for PV systems to disconnect from the grid during times of fault would, in a world with large quantities of PV installed, lead to a large amount of generation disconnecting from the system at the time of the fault, thus propagating the fault. As a precedent, grid codes have evolved in a number of countries to address this very issue - by mandating wind generators to have 'low voltage ride through' capabilities.

[42] and [43] highlight the important role inverters have in a world with large amounts of photovoltaics connected to the power system. This important role stems from the fact that it is the inverter that controls the interaction between the photovoltaic facility and the broader power system, and the ability of inverter power electronics to control the phase angle of the output and to correct deviations in the sinusoidal wave of the actual grid voltage. Implicit in this discussion is the requirement for the development of a more active, dynamic transmission / distribution system with real time communication between control centres and agents connecting to the grid to ensure optimum system operation. This is in contrast to the paradigm currently in place where a system is generally designed for a static worst-case scenario.

Another implication of increased quantities of variable and somewhat uncertain gener-

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[2] Under IEEE 1547 'Standard for Interconnecting Distributed Resources with Electric Power Systems, 2003'

ation entering the power system is an increased requirement for operating reserves. The management of up- and down- reserves in a power system is the means by which fluctuating and somewhat uncertain electricity demand is matched second by second. Less than perfect prediction of photovoltaic generation output will add to the uncertainty in net load second-by-second and thus will require an increase in the available up- and down- reserves. The extent of the reserves required vary from system-to-system, with the relevant factors including the system's interconnection capacity, the system's technology mix and the weather characteristics of the particular system.

A number of open questions exist about the ability to maintain stability on a power system with large quantities of photovoltaics. Conventional generators (including those that are included in CSP plants) have huge mechanical inertia which buffers against sudden changes in power output. This inertia can help facilitate recovery of the system from a fault. Photovoltaics do not have this inertia, as generation of a photovoltaic cell is directly proportional to the incoming solar radiation at each instant. [44] identifies 2 deficiencies in current data and tools to fully assess this issue; a) the non-existence of systematic 1 minute or sub minute solar radiation data for power system - wide geographic areas and b) the lack of power system stability models that model PV modules / inverters to the level of detail required to assess the stability impacts of large quantities of photovoltaics.[3]

In addition to the lack of mechanical inertia to help the system recover from a fault, the nature of PV electricity generation leads to a possibility for fast moving clouds to cause significant short term fluctuations. Large fluctuations would make the management of system operation more challenging. At the current low levels of installed capacity such fluctuations in PV output are lost in the noise of demand agents turning on-and-off lights and appliances, but at higher levels such fluctuations could become very significant. Again, the lack of systematic short timescale solar radiation data is an issue here. The aggregate PV output across a geographic area will have a smoother profile however than an individual power plant. [17] show for a number of studied sites in the Western United States a decrease in one-minute ramp extremes when aggregate areas are considered instead of individual plants. This smoothing effect can be even noticed across inverter output of a large PV

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[3] These problems are also relevant for wind generation. [45] represents a major study undertaken on the Irish power system. Two issues were found to limit the acceptable level of wind penetration at any instant: a) frequency stability after loss of generation and b) frequency as well as transient stability after severe network faults.

plant. [46] considers the smoothing effect across 52 PV sites in Japan and propose a model for estimating the aggregate variability of PV plants across a geographic area, with the timescale considered and the distance between plants the primary factors behind the correlation of variability between plants.

Examples of studies where limited quantities of PV generation (along with wind generation) were found to be technically feasible for particular power systems include [47] and [48]. It is natural to ask however what the technical limit is to solar power's contribution to a power system. There is no single answer due to current gaps in the knowledge (as outlined in the previous paragraphs) but also as it depends on many system-specific issues. In addition, economic factors will also play a large role - how much is society willing to spend on capacity payments for backup thermal generation, how much for energy storage, operating reserves, transmission and distribution upgrades - what is technically feasible may not be economically acceptable.

[33] considers the limits to the penetration of photovoltaics on a power system and using a production cost model for the ERCOT system show that technical constraints on the minimum production of baseload (based on the economic costs and inefficiency of baseload cycling) will lead to excess PV generation as penetration levels increase. Like the above, this highlights the interrelated technical and economic issues associated with solar power deployment, thus moving the discussion toward the next section.

Finally for this section; as the existing contribution of solar power to power systems is relatively small, much of this discussion is the result of modelling work. Some lessons can be learned however from areas where solar power has been more prevalent. The prime example is Germany, where a strong feed-in-tariff system for solar energy has led Germany to have the greatest quantity of photovoltaic capacity in the world. [49] provides an overview of network integration issues that have occurred in Germany, mainly focussing on distribution grid issues, grid code updates and contributions of inverters to power quality.

3.2 Economic Implications

[50] discusses previous work where it is asserted that as the penetration of renewable energies increases significantly, the long-term economic value of the next installation will decrease. In addition, [50] states that it is not always made clear why this is the case, and provides

an explanation. This explanation is expanded upon in detail in Chapter 5, where a similar framework is extended to incorporate network constraints.

Under the static optimisation framework of [50], it is stated that the long-term value in a renewable generator derives from the decline in baseload costs on the system, in line with a finding by [51].

On the other hand, [52] states that the economic value of renewable generation largely derives from a reduction in gas plant fuel costs. Similarly, [53] cites the benefit of photovoltaics in replacing gas generation due to the correlation between PV and peak demand. This discrepancy can be partly explained by the difference between assessing the long term capacity value versus assessing the short term energy value. In addition, the benefit shall be a function of the fraction of the energy on a system supplied by photovoltaics. For example, the latter finding of [53] holds for the next solar unit in a system with a low quantity of installed solar capacity, when considered in a model with no expansion variables. The former finding (of [50]) however relates to how the system adapts when compared across static optimisation scenarios. The work of this thesis largely relates to the latter - discussion on this topic is expanded upon in Chapters 5 and 6.

[52] also notes that the economic value of surplus PV (and wind) generation is zero, and thus states that curtailment of excess generation is an economic limit to PV deployment - thus providing an indication of the benefit of energy storage or demand shifting. The ability of CSP to incorporate thermal storage can thus be seen to potentially have a strong economic value in the context of large-scale deployment of solar power, and is the major differentiating factor between CSP and PV in the context of this discussion.

A number of studies (e.g. [54]) show the need for more flexible conventional generation in a power system with large quantities of renewables present. Generation capacity will be required to be available to produce power when the wind is not blowing and the sun is not shining. The economic characteristics of peaking capacity are such (low fixed costs, high variable costs) that it is most appropriate to provide this type of service. As the electricity market price will be depressed by the renewable generator during hours of strong availability, conventional generation will require very high electricity prices during the hours they are called upon in order to cover their full costs.

Much discussion has focussed on the ‘integration costs’ associated with the capacity of renewable energy installed (for example, see [55] and [56]). Integration costs in this context can be defined in a number of ways, but can include for example the cost of transmission upgrades to incorporate the new generation and the cost of additional ancillary services to cope with the resources variability. It is perhaps questionable whether this is a valid metric as *each* technology on a power system is shaped by system requirements while at the same time shaping the system around it. The issue of 'integration cost' becomes more relevant in a market based environment where it is difficult to determine who is the cause of costs, and thus who should pay. In addition, there is a distinction between the case of a new competitive technology entering a system and the system adapting accordingly, and the case of renewable generation 'forced' onto the system by public policy. In the latter case, from the system perspective, the policy is imposing an extra cost. Values estimated for the extent of this cost will vary by system and underlying assumptions but sample figures for wind are 5-8 £/MWh in [55] (for operating and capacity costs for the British system) and 2-5 \$/MWh in [56] (for the operating cost impact for a sample of U.S. utilities).

A number of studies (for example, [57], [58], and [59]), focussing primarily on wind generation, have shown reductions in the market price of power in the Spanish, Danish and German electricity markets due to the presence of zero-variable cost renewable generation on the system. These findings have been claimed to offset the costs of renewable energy support schemes in these systems. A distinction must be made here, however, between short term and long term impact on power prices with the long term impact more uncertain - depending on what investment takes place by conventional generators and what (if any) externalities are included in the power price.

3.3 Regulatory Implications

[43] and [44] state how grid codes and standards will need to be updated to reflect the possibility of larger quantities of PV (distributed and centralised) on the system. In addition, incentive systems could be put in place to harness inverters' capability to provide beneficial services to the grid. If no incentive exists, there is no reason to expect inverters to provide them.

The issue of ensuring capacity is on hand to provide electricity when the sun does not shine or the wind does not blow, in the context of reduced electricity prices when they are, is an issue that has been highlighted in a study of high wind penetration scenarios in the Irish and British electricity markets [54]. Without a capacity payment in the market, an energy only market price could rise to the order of thousands of dollars / MWh at some hours of the year in order for peaking plants to be adequately remunerated. With the inclusion of a capacity payment, the complex question arises of how to determine what level of firm capacity a solar generator is providing to the system. [60] outlines different methods of estimating the capacity credit of a PV plant. The capacity credit will be a function of the correlation between solar generation and peak demand and thus will also be a function of PV penetration - as when the peak net load occurs will shift as the penetration increases. The estimation of the capacity credit of a plant is also an important issue in the system planning of resource adequacy.

Electricity markets and market rules were typically designed for the paradigm of conventional generation. Some areas where renewable electricity is popular have adopted market rules that are adapted to recognise the different characteristics of renewable generators. Such changes have occurred for wind in a number of systems (for example, ERCOT, NY-ISO, CaISO), while an example of solar-specific rules is the ongoing adaption of the CaISO PIRP (Participating Intermittent Resource Program) scheme.[4] An example of such an adaption is to penalise the monthly average deviation from the market bid quantity as opposed to each discrepancy (as would be the case for conventional generators).

Reflecting the above discussion, [62] notes that much of the literature focuses on 'integrating' renewables once they enter a power system, but little attention is paid to the policies that get them there in the first place. [63] considers the effectiveness and efficiency of renewable support policies employed across the E.U. from the perspective of the quantity of renewable sources which enter systems. [64] makes the case that large-scale deployment of wind generation beyond current levels in the E.U. may require a re-design of support policies - particularly in terms of the market and locational signals received by wind generators. This latter issue is addressed in this thesis (see Chapter 8 especially), with the findings for solar power largely relevant to wind power also.

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[4] See [61] for further information on the evolution of this ongoing process.

3.4 Chapter Summary

The goal of this chapter was to provide the reader with a broad overview of the multidisciplinary literature that reflects the implications of solar power deployment.

As may have been apparent, many of the implications discussed related to photovoltaics as opposed to CSP. This is justified by the more well understood characteristics of CSP generation. Of the PV implications discussed, many of the implications are also relevant to wind power. The technical implications are most PV-specific, while the economic and regulatory implications are most commonly shared with wind. What differentiates PV generation in the broader economic and regulatory contexts is the pattern of the solar radiation profile - the energy is available during the day, when a significant portion of the demand is also. This is also true for CSP, with the ability to provide storage a differentiating factor.

Chapter 4

Modelling Methodology

Following the provision of the background information of Chapter 2 and the discussion of previous work of Chapter 3, this chapter sets up the modelling methodologies applied in the remainder of this thesis.

As stated previously, the underlying goal of this thesis is to gain an understanding of the potential implications of large-scale solar power deployment. Thus, by definition this thesis looks into the future, an inherently difficult thing to do. The approach that is turned to is that of mathematical models. Many options exist in terms of the scale and complexity of available models and the choice of the appropriate type of model depends on the question being asked. Models relevant to the power sector can range from simulation analysis of the performance of components of the system to economic dispatch optimisation models to general equilibrium models of a whole economy, with the power sector as a component. Depending on the question being asked, the time horizon considered can vary considerably. For example, transient stability analysis models of the power system consider the sub-second timescale whereas generation planning models consider the decadal timescale.

Thus, power system models can be broadly categorised as expansion models (generation, transmission or both), production cost models, hydro-thermal co-ordination models, unit commitment models, economic dispatch models, load flow models, and protection/stability models. As the deployment of solar power is the issue at the core of this thesis, expansion models are thus the focus. The following section provides a non-exhaustive overview of expansion models that have been developed by various parties.

4.1 Expansion Model Overview

ReEDS: The NREL developed Regional Energy Deployment System (ReEDS) model is a linear programming optimisation model. The model consists of a series of 2-year timesteps and can be run to any year up to 2050. At each optimisation timestep, the model minimises the total electricity system cost, including new capacity, transmission, and production. More information about the ReEDS model can be found in [65]. One of the primary strengths of the ReEDS model is the high degree of spatial resolution it contains, with the renewable resource capacities of 356 areas included. For each optimisation timestep, electricity demand is met for 17 timeslices, 4 representative slices for each season plus a super peak, cumulatively representing a load duration curve. The model adopts a 'transportation model' approach toward transmission, with aggregate transmission capacity between each region an input to the model and the only constraint of electric energy flow between areas.

During the course of this work, the author spent some time at the NREL facility in Golden, Colorado to learn the model structure and operation. The model is used as part of the analysis later in the thesis (Chapter 7), where additional details of the model are discussed. The model has been developed for a number of years and has been used in a number of well-publicised works such as [66]. Photovoltaics have been incorporated into the model only recently.

Other models: Numerous other models have been developed to answer similar scale questions about the deployment of renewable energy technologies, particularly wind. [52] developed a model of the California power system including solar power technology. [52] also discusses models developed by [67] and [68]. These latter models were developed to consider the onset of wind generation onto a power system. Differences of note across the modelling structures include the number of nodes considered, the representation of renewable energy variability, the number of optimisation timesteps (investment periods), the number of dispatch periods per timestep, the treatment of transmission, the treatment of transmission expansion, and what underlying system the model is applied to (if any). The paradigm of all these models is cost minimisation.

General Equilibrium Models: Long range expansion models constitute partial equilibrium analysis, and thus do not capture general equilibrium effects. Rapid expansion of one technology for example would lead to feedback effects through an economy that endogenously would affect energy prices, electricity demand, costs of other technologies etc. - effects that would not be captured in partial equilibrium analysis. General equilibrium models that have an energy component include NEMS [69], EPPA [70], and MERGE [71]. The paradigm of these models is welfare maximisation.

4.2 Approach Chosen

Despite having access to the ReEDS model, it was decided to additionally adapt, develop, and implement an independent power system model, subsequently entitled Expan. The reasons for so doing were as follows:

- The development process of a smaller model, with only key constraints included, had the attraction of providing insights that could be harder to identify among all the complexities and associated interactions of a larger model like ReEDS.
- The smaller model framework allowed analytical development to highlight the trade-offs at the optimum solution. In particular, the model framework was developed to analytically assess the components of the marginal benefit of a renewable generator under network constraints.
- The independent development of the model allowed the inclusion of 8760 dispatch periods into the single static optimisation timeperiod. This allowed increased representation of the pattern of renewable generation compared to the 17 dispatch periods in ReEDS.
- It was also possible to include a linearised DC load flow model. While still a large simplification of the AC version, this provided an improvement on using the ‘transport model’ approach.
- Transmission expansion variables were also included. As discussed in Section 8.2, the representation of existing and new transmission capacity in the model as a continuous variable is a large simplification of the reality of the technology.

To consolidate the work of the Expan model, the ReEDS model was later applied to the ERCOT system and the U.S. system.

4.2.1 Application of Model

Upon development of the model, the model could be applied in a number of ways. A frequent approach used in the literature is to apply a developed model or methodology to an abstract standard system. Examples of such a system include the IEEE 39-bus standard system (as applied in [42]), or to a system such as that found in [72], subsequently applied in [73].

It was decided instead to apply the model to a representation of a real power system. The application of the model framework to a real system as opposed to an abstract system allowed the spatial and temporal distribution of real (as opposed to arbitrary) solar and wind resources to be included in the analysis. For reasons discussed in Section 6.1.1, the model was specifically applied to the ERCOT (Electricity Reliability Council of Texas) power system.

4.2.2 Modelling of Renewable Energy

Considering solar power is the focus of this thesis, it is worthwhile to expand upon the modelling of PV, CSP, and wind generation in the developed model. The first element to note is that these renewable energy resources are modelled on an hourly timescale. As previously outlined in Section 3.1, sub-hourly timescales are very important in the operation of a power system. While numerical limitations would prevent a finer representation of the temporal scale, the balance of outputs of a number of renewable generators across a region could potentially smooth the sub-hourly output, increasing the validity of using hourly output for this analysis (analysis by [60] supports this finding). In addition, including 8760 dispatch periods captures more information than the smaller number typically used in expansion models.

Photovoltaics

Photovoltaics are modelled as generators where the fraction of nameplate capacity available each hour, PF_h, is calculated as $\frac{GHI}{1000W/m^2}$, where GHI stands for Global Horizontal Insolation, representing the intensity of sunlight striking the solar panel. The values for GHI are based on historical data. The dataset used for this model provides global insolation striking a horizontal panel. Ideally this input should be adjusted to include panel tilt to maximise the solar energy collected [5]. This step was not taken for simplicity however, leading to an inherent disadvantage for PV incorporated in the model. In addition to this disadvantage, tracking systems are not included, another step which could boost the power output of a PV plant per incoming unit of solar radiation on a horizontal surface.

Concentrating Solar Power

The modelling of Concentrating Solar Power is a more complex process as the relationship between incoming solar radiation and production is non-linear, with a number of design decisions affecting the relationship. In addition, the transfer of energy across hours in the form of thermal storage can be included.

For this work, a fixed relationship between electric generation turbine capacity, quantity of thermal storage and collector area is applied to the CSP modelling formulation as presented in [74]. In this application a value of $900 W/m^2$ is chosen as the insolation reference value, along with a solar multiple value of 2, and thermal storage of 6 hours. The equations representing this formulation are presented in Section 5.5.4.

Thus, for a CSP plant with 100MW capacity, the collector area is assumed to be large enough to collect 200MW of electric energy equivalent when insolation is at the reference value. In addition the same plant will have the ability to store 600MWh electric energy equivalent.

Wind

Similarly to PV, wind generators are modelled as generators where there is a fraction of nameplate capacity available each hour for production, PF_h. In the case of wind energy, the PF factors are derived from production profiles by area as produced by ERCOT.

Qualifications

Before leaving this section, there is an important conceptual point to make about the modelling of these three renewable energy technologies. This point stems from the resource availability in each hour being a deterministic input to the model. The perfect knowledge of wind or solar resource availability implicitly assumed here does not exist in reality (particularly for 20 years in the future), and thus it could ideally be modelled with some sort of probability distribution. Or, a more appropriate approach may be to include forecast errors in the model, with a requirement for operating reserves to be available to account for errors in the forecast. This is the process by which uncertainty in demand is managed in the operation of power systems.

4.3 Limitations of Modelling

To conclude this chapter, it is worthwhile to say a few words on the concept of modelling in general. Models of the type used here should not be used to predict behaviour of the huge system in question and determine the ‘optimal’ action to take. This type of model should however provide insights into relationships of various system components and behaviours. In addition, a model can highlight possible implications of proposed actions which would not be apparent at the time of the initial decision. Finally, a commonly cited benefit is the attraction of some quantification as opposed to solely relying on ‘hunches’. However, the danger of using this quantification as a truth to advocate for an overlying agenda is ever-present.

[75] provides a thorough breakdown between these two modelling paradigms - predictive ‘consolidative’ modelling and ‘exploratory’ modelling, stating that the latter when undertaken properly can help in hypothesis generation, providing new cases to think about, and can show where predicted behaviours lead to outcomes different from initial expectations. It is with this paradigm in mind that this thesis uses the enclosed models - to fuel further discussion and provide insights into the possible implications of large-scale solar power deployment.

Chapter 5

Expan Model Formulation and Analytical Development

This chapter presents the formulation of the linear programming model, entitled Expan, that has been developed to analyse the implications of solar power deployment.[1] Why this modelling approach was pursued is discussed in Section 4.2. In addition to presenting the form and structure of the model, this chapter's purpose is to a) provide insights into how the model chooses from the various investment and production options, b) provide a framework for understanding how network effects influence the marginal benefit of a renewable generator, c) consider the implications of the framework for the deployment of solar technologies in particular and d) provide insight into how solar-energy supports schemes operate within the context of the model framework.

Models that focus on generation capacity expansion typically negate or treat transmission in a simplistic fashion. Good reasons exist for doing so, as combining approaches requires simplifications to the individual approaches. However, as patterns, insights and understanding are of more interest here than absolutes, these approaches are combined and adapted to develop the modelling framework as detailed below. The framework is developed with the over-arching goal of incorporating the technical constraints imposed by the physical laws of the power system into the discussion on the economic and regulatory implications

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[1] Initial model formulation was kindly provided by Professor Andrés Ramos of El Instituto de Investigación Tecnológica of Madrid during a sabbatical stay at MIT during the summer of 2009. Further model development benefitted from studying the works of [76], [50] and [77]. This process additionally benefitted from the ESD.940 course at MIT in January of 2010 and a series of modelling discussions with Ignacio Pérez-Arriaga, Bryan Palmintier and Yuan Yao at MITEI during Spring of 2010.

associated with growth in solar power deployment.

5.1 Model Structure

The model ensures that a specified electricity demand is satisfied in a future year by finding the optimal mix of new capacity investment and production mix, as per the economic inputs and assumptions of the model, and subject to the network constraints placed by the inclusion of a DC load flow model representation.

5.1.1 Terminology

Sets

g = Generators
h = Hours
ni, nf, nd = Alias names for nodes 1 to n
$l(ni, nf)$ = Transmission line from node ni to node nf

Variables

PTI_g = New capacity of generator g
$PTP_{h,g}$ = Production of generator g in hour h
$TTC_{l(ni,nf)}$ = New transmission capacity on line $l(ni, nf)$
$FLE_{h,l(ni,nf)}$ = Flow on transmission line between nodes ni and nf in hour h
$TT_{h,ni}$ = Phase angle at node ni at hour h

Parameters

FC_g = Annual fixed cost of one unit of capacity of generator g
CVR_g = Variable cost of production of generator g
$FCt_{l(ni,nf)}$ = Annual fixed cost of one unit of transmission capacity of line $l(ni, nf)$
$DMD_{h,nd}$ = Demand at node nd at hour h
$V_{l(ni,nf)}$ = Line-line voltage on line $l(ni, nf)$ [assumed constant across system]
$X_{l(ni,nf)}$ = Reactance of line $l(ni, nf)$
$PF_{h,g}$ = Production capability factor of generator g in hour h

5.1.2 Model Formulation

Objective Function

The model is designed to minimise the sum of annual electricity production costs and annualised generation capacity and transmission capital costs:

$$\min Z = \sum_{g} PTI_g FC_g + \sum_{g} \sum_{h} PTP_{h,g} CVR_g + \sum_{l(ni,nf)} TTC_{l(ni,nf)} FCt_{l(ni,nf)} \tag{5.1}$$

Model Constraints

The model constraints are as follows:

Electric energy supply-demand balance at each node in each hour:

$$\sum_{g \in g(nd)} PTP_{h,g} + \sum_{l(ni,nd)} FLE_{h,l(ni,nd)} - \sum_{l(nd,nf)} FLE_{h,l(nd,nf)} = DMD_{h,nd} \qquad \forall h, nd \tag{5.2}$$

Electricity generation by each generator less than generator's available capacity in each hour:

$$PTP_{h,g} \leq PTI_g PF_{h,g} \qquad \forall h, g \tag{5.3}$$

Power flow in each line less than line's specified 'power transfer capability':

$$FLE_{h,l(ni,nf)} \leq TTC_{l(ni,nf)} \qquad \forall h, l(ni,nf) \tag{5.4}$$

$$FLE_{h,l(ni,nf)} \geq -TTC_{l(ni,nf)} \qquad \forall h, l(ni,nf) \tag{5.5}$$

Power Flow Equation: [2]

$$FLE_{h,l(ni,nf)} = \frac{\left|V_{l(ni,nf)}\right| \left|V_{l(ni,nf)}\right| (TT_{h,ni} - TT_{h,nf})}{X_{l(ni,nf)}} \qquad \forall h, l(ni,nf) \tag{5.6}$$

---

[2] Equation (5.6) is a necessary component of the DC load flow model and allows inclusion of Kirchoff's Voltage Law in addition to Kirchoff's Current Law of equation (5.2). In the later application of this model to a sample power system, voltage values and reactances shall be chosen such that this constraint shall have a very small degree of influence. To do otherwise would be inconsistent as under the linear model framework, what is defined as transmission capacity, TTC, can be expanded, while the values of X and V can not be changed, irrelevant of any associated benefits. While not ideal, this configuration allows the model include DC load flow as opposed to using a 'transportation' model. Finally, a detailed discussion of what constitutes the power flow capacity of a transmission line is provided in Section 8.2.

Voltage phase angle constrained to 90° (Section 8.2):

$$|TT_{h,nd}| \leq 1.5 \qquad \forall h, nd \tag{5.7}$$

Transmission investment, generation investment and electricity production must remain non-negative:

$$TTC_{l(ni,nf)},\ PTI_{l(ni,nf)},\ PTP_{h,g} \geq 0 \qquad \forall h, l(ni,nf), g \tag{5.8}$$

5.1.3 Core Analytical Development

This sub-section highlights the core analytical development that underlies discussion and development for the remainder of this chapter and beyond.

Each model constraint above has an associated dual variable (or shadow price) at the optimal solution.[3] Each dual variable represents how much the objective function will change should the dual variable's associated constraint be relaxed by 1 unit. This provides useful information about the influence of each constraint on the optimal solution, being particularly useful in its relation to the economic concept of the marginal unit. For example, the $\lambda_{h,nd}$ dual variables represent how much the system cost will change per unit change in demand. This actually represents the marginal price of electricity at each node nd in hour h, and thus can be used, in combination with the other dual variables, to develop significant insight about the optimal solution (as will be attempted below).

---

[3] Many comprehensive references exist on the theory of linear optimisation - an example is [78].

Lagrangian

Pairing each constraint with its associated dual variable, the Lagrangian of the model formulation can be expressed as follows:

$$
\begin{aligned}
L = \sum_{g} PTI_g FC_g + \sum_{g}\sum_{h} PTP_{h,g} CVR_g + \sum_{l(ni,nf)} TTC_{l(ni,nf)} FCt_{l(ni,nf)} \\
+ \sum_{h}\sum_{nd} \lambda_{h,nd} \left(DMD_{h,nd} - \sum_{g \in g(nd)} PTP_{g,h} - \sum_{l(ni,nd)} FLE_{h,l(ni,nd)} + \sum_{l(nd,nf)} FLE_{h,l(nd,nf)} \right) \\
+ \sum_{h}\sum_{g} \gamma_{h,g} (PTP_{h,g} - PTI_g PF_{h,g}) \\
+ \sum_{h}\sum_{l(ni,nf)} \beta^1_{h,l(ni,nf)} (FLE_{l(ni,nf)} - TTC_{l(ni,nf)}) \\
+ \sum_{h}\sum_{l(ni,nf)} \beta^2_{h,l(ni,nf)} (-FLE_{l(ni,nf)} - TTC_{l(ni,nf)}) \\
+ \sum_{h}\sum_{l(ni,nf)} \alpha_{h,l(ni,nf)} \left(\left(\frac{|V_{l(ni,nf)}|\,|V_{l(ni,nf)}|}{X_{l(ni,nf)}} (TT_{h,ni} - TT_{h,nf}) - FLE_{l(ni,nf)} \right) \right) \\
+ \sum_{h}\sum_{nd} \kappa^1_{h,nd} (TT_{h,nd} - 1.5) \\
+ \sum_{h}\sum_{nd} \kappa^2_{h,nd} (-TT_{h,nd} - 1.5) \\
+ \mu^1_{l(ni,nf)} TTC_{l(ni,nf)} + \mu^2_g PTI_g + \mu^3_{h,g} PTP_{h,g}
\end{aligned}
\tag{5.9}
$$

First Order Conditions

$$\frac{\partial L}{\partial FLE_{l(ni,nd),h}} = \lambda_{h,ni} - \lambda_{h,nd} - \alpha_{h,l(ni,nd)} + \beta^1_{h,l(ni,nd)} - \beta^2_{h,l(ni,nd)} = 0 \qquad \forall l(ni,nd), h \tag{5.10}$$

$$\frac{\partial L}{\partial TTC_{l(ni,nd),h}} = FCt_{l(ni,nd)} - \sum_{h} \beta^1_{h,l(ni,nd)} - \sum_{h} \beta^2_{h,l(ni,nd)} + \mu^1_{l(ni,nd)} = 0 \qquad \forall l(ni,nd) \tag{5.11}$$

$$\frac{\partial L}{\partial PTI_g} = FC_g - \sum_{h} \gamma_{h,g} PF_{h,g} + \mu^2_g = 0 \qquad \forall g \tag{5.12}$$

$$\frac{\partial L}{\partial PTP_{h,g}} = CVR_g - \lambda_{h,nd} + \gamma_{h,g} + \mu^3_{h,g} = 0 \qquad \forall nd, h, g \in g(nd) \tag{5.13}$$

$$\frac{\partial L}{\partial TT_{h,ni}} = \alpha_{h,l(ni,nf)} \frac{\left(\left|V_{l(ni,nf)}\right| \left|V_{l(ni,nf)}\right|\right)}{X_{l(ni,nf)}} + \kappa^1_{h,ni} - \kappa^2_{h,ni} = 0 \qquad \forall h, ni \tag{5.14}$$

$$\gamma_{h,g} \left(PTP_{h,g} - PTI_g PF_{h,g}\right) = 0 \qquad \forall h, g \tag{5.15}$$

$$\beta^1_{h,l(ni,nf)} \left(FLE_{l(ni,nf)} - TTC_{l(ni,nf)}\right) = 0 \qquad \forall h, l(ni,nf) \tag{5.16}$$

$$\beta^2_{h,l(ni,nf)} \left(-FLE_{l(ni,nf)} - TTC_{l(ni,nf)}\right) = 0 \qquad \forall h, l(ni,nf) \tag{5.17}$$

$$\mu^1_{l(ni,nf)} TTC_{l(ni,nf)} = 0,\ \mu^2_g PTI_g = 0,\ \mu^3_{h,g} PTP_{h,g} = 0 \qquad \forall h, g, l(ni,nf) \tag{5.18}$$

As per the complementary slackness conditions of equation (5.18), the μ terms can only be non-zero when their associated terms are zero, i.e. when $TTC_{l(ni,nf)}$, PTI_g or $PTP_{h,g} = 0$. As the cases of interest are those where positive transmission investment, generation investment, and electricity production occur, the μ terms are generally not included in the development of the first-order conditions in the following section, and only included where they have an influence on a result.

5.2 Source of Nodal Price Differentiation

Equation (5.10) above can be re-written as:

$$\lambda_{h,ni} = \lambda_{h,nd} + \alpha_{h,l(ni,nd)} - \beta^1_{h,l(ni,nd)} + \beta^2_{h,l(ni,nd)} \qquad \forall h, l(ni,nd) \tag{5.19}$$

This equation provides insight into where nodal price differences originate in a loss-less power system. In a system without any transmission constraints the α and β terms will be 0 and the nodal price will be the same at each node. However in a system where transmission constraints bind for at least some hours, the nodal price differential can stem from two sources in the context of this model - the shadow price of the transmission capacity limitation, β, and the shadow price of any constraint placed by relative phase angles, α. This equation serves as the basis for further analytical development in later sections.

5.3 Model Investment Decisions

Level of Transmission Investment

For a case where $\mu^1_{l(ni,nf)} = 0$, and a positive quantity of transmission capacity is constructed along a transmission corridor $l(ni,nf)$, equation (5.11) above can be re-written as:

$$FCt_{l(ni,nd)} = \sum_h (\beta^1_{h,l(ni,nf)} + \beta^2_{h,l(ni,nf)}) \qquad \forall l(ni,nd) \tag{5.20}$$

Where $\beta^1_{h,l(ni,nf)}$ and $\beta^2_{h,l(ni,nf)}$ represent the dual variables of the constraint that limits the flow of a line to the transmission capacity of that line. This equation thus shows that the model will construct new transmission capacity along a transmission corridor until such point as the sum of the shadow price of the constraint over the year is equal to the fixed cost of an incremental increase in capacity. Thus it can be interpreted that the marginal value of a unit of transmission capacity along a corridor equals the sum of the costs of the transmission constraint over the year. This equation provides insight into how the model chooses the quantity of transmission that it invests in.

Level of Generation Investment

For a case where there is investment in the capacity of generator g, and thus $\mu^2_g = 0$, equation (5.12) above can be re-written as:

$$FC_g = \sum_h \gamma_{h,g} PF_{h,g} \qquad \forall g \tag{5.21}$$

γ represents the shadow price of the production of a generator being constrained by its available capacity in any given hour, and is non-zero when a generator is dispatched to full available capacity for that hour. This equation thus states that it is worthwhile to construct an additional unit of capacity while the incremental cost of doing so is less than the sum of the shadow price of the constraint in a given year, adjusted by the availability factor, PF. Thus when γ is zero for every hour of the year, no justification for an incremental increase in capacity exists. Likewise, if PF is zero for every hour of the year, then no justification for a positive-costing incremental increase in capacity exists.

For further development, equation (5.13) can be re-written as follows:

$$\gamma_{h,g} = \lambda_{h,nd} - CVR_g - \mu^3_{h,g} \qquad \forall nd, h, g \in g(nd) \tag{5.22}$$

Combining equations (5.21) and (5.22) yields:

$$FC_g = \sum_h (\lambda_{h,nd\exists g \in g(nd)} - CVR_g - \mu^3_{h,g}) PF_{h,g} \qquad \forall g \tag{5.23}$$

Level of Generation Investment in PV or Wind Capacity

At this point the discussion can now relate to what is different about wind and photovoltaic generators relevant to conventional generators under this analysis framework. 4 characteristics are identified here:

1. First of all, while ignoring a number of the realities of electricity generation, for the purposes of this analysis, conventional thermal generators can be assumed to have a PF of 1 for each hour of the year. PV and wind generators on the other hand can be assumed to have a PF that varies for each hour of the year depending upon the characteristics of the underlying 'prime mover' resource.
2. Secondly, the economic characteristics of PV and wind power are such that CVR can be approximated as 0.
3. Thirdly, the economic characteristic of point 2 entails that once the PV or wind generating capacity is installed they will always be first in the dispatch order, and γ will be > 0 for every hour.
4. Fourthly, point 2 also entails that $\mu^3_{h,g}$ will always be zero for a PV or wind generator (as a theoretical negative production would not affect the objective function).

This combination of factors is such that for a renewable (PV or wind) generator gr, located at node ni, equation (5.23) can be expressed as follows:

$$FC_{gr} = \sum_h^H \lambda_{h,ni} PF_{h,gr} \qquad \forall ni, gr \in g(ni) \tag{5.24}$$

Thus the model will add renewable generation capacity until the optimal solution is arrived at and the right hand side of the equation above equals the left hand side, i.e. to the point where the marginal benefit of investment in a renewable generator equals the marginal fixed cost. Thus the right hand side of equation (5.24) can be considered the marginal benefit or the marginal 'system' value of the renewable generator, MV_{gr}.

5.4 Marginal 'System' Value of PV or Wind Capacity Under Network Constraints

5.4.1 Framework Development

A limitation to the expression of PV or wind (here termed renewable) capacity marginal value provided by equation (5.24) is that it does not allow determination *a priori* of the impact of the transmission network on the marginal system value of renewable energy sources - as the shadow prices included within the equation, $\lambda_{h,nd}$, are an output of the optimisation process. Addressing this issue for a 1-node system with one hourly system marginal price, λ, Lamont [50], using equation (5.24) takes the following steps to articulate the components of the system value of a renewable generator, gr:

$$\begin{aligned} MargVal_{gr} &= \sum_{h=1}^{H}[\lambda_h.PF_{gr,h}] = H.E(\lambda.PF_{gr}) \\ Cov(\lambda, PF_{gr}) &= E(\lambda.PF_{gr}) - E(\lambda).E(PF_{gr}) \\ MargVal_{gr} &= H.E(\lambda).CF_{gr} + H.Cov(\lambda, PF_{gr}) \end{aligned} \tag{5.25}$$

Where E(X) is the time weighted average of X.

[50] holds that the first term in the above equation, $H.E(\lambda)$, will remain constant across all scenarios, provided that baseload generation is not completely displaced in any hour of the year. In addition, the term holds constant at a level equal to $FC_{trb} + CVR_{trb}$, where trb represents a baseload generator which is dispatched in each hour.

Not included by [50], but as we have derived previously, λ in a network system will vary from node-to-node depending upon transmission constraints. Thus, for a renewable generator, gr, located at node ni:

$$MV_{gr} = H.E(\lambda_{ni}).CF_{gr} + H.Cov(\lambda_{ni}, PF_{gr}) \tag{5.26}$$

What causes this equation to be of interest is that the value may vary from node to node depending upon the difference in nodal prices. To determine whether anything interesting can be learned from the underlying driving factors, the following additional analysis is undertaken, beginning with the following rearrangement of equation (5.24).

$$MV_{gr} = FC_{gr} = \sum_{h}^{H} \lambda_{h,ni} PF_{h,gr} = H.E(\lambda_{ni}.PF_{gr}) \qquad \forall ni, gr \in g(ni) \tag{5.27}$$

Recalling equation (5.19), the expression of equation (5.27) is now modified to include what would be the system marginal price in the absence of transmission constraints, set by a baseload generator at node nd, to which node ni is connected by a transmission line $l(ni, nd)$:

$$MV_{gr} = H.E\left((\lambda_{nd} + \alpha_{l(ni,nd)} - \beta^1_{l(ni,nd)} + \beta^2_{l(ni,nd)})PF_{gr}\right)$$

Manipulating the expectations:

$$MV_{gr} = H\left[E(\lambda_{nd}.PF) + E(\alpha_{l(ni,nd)}.PF_{gr}) - E(\beta^1_{l(ni,nd)}.PF_{gr}) + E(\beta^2_{l(ni,nd)}PF_{gr})\right]$$

$$\begin{aligned} MV_{gr} &= H.E(\lambda_{nd}).CF_{gr} + H.cov(\lambda_{nd}, PF_{gr}) \\ &+ H.E(\alpha_{l(ni,nd)})CF_{gr} + H.cov(\alpha_{l(ni,nd)}, PF_{gr}) \\ &- H.E(\beta^1_{l(ni,nd)}).CF_{gr} - H.cov(\beta^1_{l(ni,nd)}, PF_{gr}) \\ &+ H.E(\beta^2_{l(ni,nd)}).CF_{gr} + H.cov(\beta^2_{l(ni,nd)}, PF_{gr}) \end{aligned} \tag{5.28}$$

Where $CF_{gr} = E(PF_{gr})$

Then, working with equation (5.20), $H.E(\beta^1_{l(ni,nd)})$ can be broken down as follows:

$$\begin{aligned} FCt_{l(ni,nd)} &= H.E(\beta^1_{l(ni,nd)}) + H.E(\beta^2_{l(ni,nd)}) \\ H.E(\beta^1_{l(ni,nd)}) &= FCt_{l(ni,nd)} - H.E(\beta^2_{l(ni,nd)}) \end{aligned} \tag{5.29}$$

Substituting into equation (5.28) and rearranging yields:

$$\begin{aligned} MV_{gr} &= H.E(\lambda_{nd}).CF_{gr} + H.cov(\lambda_{nd}, PF_{gr}) \\ &- FCt_{l(ni,nd)}.CF_{gr} - H.cov(\beta^1_{l(ni,nd)}, PF_{gr}) \\ &+ 2H.E(\beta^2_{l(ni,nd)}).CF_{gr} + H.cov(\beta^2_{l(ni,nd)}, PF_{gr}) \\ &+ H.E(\alpha_{l(ni,nd)})CF_{gr} + H.cov(\alpha_{l(ni,nd)}, PF_{gr}) \end{aligned} \tag{5.30}$$

Thus we have an equation showing how a transmission corridor between nodes ni and nd impacts upon the marginal system value of a renewable generator located at node ni. Each term in the equation is discussed below:

5.4.2 Framework Discussion

- $H.E(\lambda_{nd}).CF_{gr}$: The system price expectation which will be set by a baseload generator at the node with which the renewable generator's node is connected, and can be determined *a priori*. This will be constant until a high level of penetration at which point the baseload generator is displaced completely in an hour.

- $H.cov(\lambda_{nd}, PF_{gr})$: This term represents the degree to which the 'system' price, λ_{nd}, and the renewable generator's pattern of production, PF, are correlated. The covariance between the production of the renewable generator at node ni and λ_{nd} is a function of both the quantity of renewable generation installed, and the extent of transmission constraint exist between the two nodes (both of which determine to what degree generator gr influences prices at node nd). As the influence on the system of the zero variable cost renewable generator increases, it can be expected that the value of this covariance term will decrease, reducing the value of the renewable generator.

- $FCt_{l(ni,nd)}.CF_{gr}$: This is a fixed term, dependent on the fixed cost of increasing the transmission capacity of a line by 1 unit of capacity. As this term will always be positive, it can be seen that it will lead to a reduction in the marginal value of a renewable generator. Note that this term is only valid when transmission capacity expansion is required. When not, the aforementioned associated $\mu^1_{l(ni,nd)}$ term would be included in this equation, negating the value of this term.

- $H.cov(\beta^1_{l(ni,nd)}, PF_{gr})$: This term represents the matching of the pattern of the power generation of the renewable capacity gr with the pattern of when the transmission constraint is binding. For a node with a large quantity of renewable capacity, gr, installed, it can be expected that the covariance will be positive between when the capacity is producing and when the constraint on power transmitted from the node is binding, leading to a decrease in the marginal value of the renewable capacity at that node. Thus when there are non-zero β terms present, it can be expected that the marginal value of the renewable generator will decrease.

- $2H.E(\beta^2_{l(ni,nd)}).CF_{gr}$: A term that is not know *a priori*, but about which some observations can be made for the case we are discussing. $\beta^2_{l(ni,nd)}$ will be non-zero in the hours node ni is importing power at line capacity. In such a case a generator at node ni provides value by helping to relieve the demand for imported power. For a remotely located node with renewable capacity, it is unlikely that that there will be a high enough demand to warrant significant quantities of importing power, thus it is unlikely that this term will have a significant impact. However, this will very much be a situation-specific issue.

  This term (and the following term) thus portray benefits for distributed generation (relevant to the case of photovoltaics).

- $H.cov(\beta^2_{l(ni,nd)}, PF_{gr})$: The overall value of the renewable generator relieving the importing power transmission constraint is dependent on whether the renewable generator produces at the times when $\beta^2_{l(ni,nd)}$ is active. At a node from which a renewable generator exports, it is unlikely that this term will be positive, but at high quantities will be negative, leading to a reduction in the marginal value of a renewable generator at the remote node ni. An illustrative example is that of a node with a large photovoltaic facility - the very times the node may require to import power is when the sun is not shining and PF is 0 or close to 0.

- $H.E(\alpha_{l(ni,nd)}).CF_{gr}$, $H.cov(\alpha_{l(ni,nd)}, PF_{gr})$: There is little that can be said a priori about this term. The covariance however between α and PF will be largely influenced by the covariance between PF and the β terms above, as the shadow price of releasing the flow constraint will be greatest when the power flow in the line is at line capacity. As discussed previously in Footnote 2, in the numerical application of this model the expected value of α will not be significant and will not have a determining impact on the marginal value of the renewable generator.

This discussion has shown how fixed value terms, low-influence expectation values and covariance terms all contribute to determining the marginal value of a renewable generator at a remote location. Considering the likely trends of each term discussed above for the case of a PV generator at a remote location, it can be hypothesised that the cumulative effect of the network constraints will lead to a reduction in the marginal value of a generator relative to a world with no transmission constraint. This entails that the point where the marginal benefit of an additional unit of a renewable generator equals the marginal fixed cost of a renewable generator occurs at a lower quantity of installed solar energy.

This reduction is driven by a faster decrease in the nodal price at the node in question relative to the rest of the system (equation 5.19). This in turn is influenced by the cost of transmission. As $FC_{tr} \rightarrow 0$, $\beta \rightarrow 0$, and thus the transmission related terms discussed above $\rightarrow 0$, leading to a system where the marginal value of a renewable generator under this framework reverts to that described by [50].

An insight which then could be drawn from this analysis is that the cost of transmission is an additional cost of solar energy deployment, thus leading to a reduction in the quantity installed in order to align the market value to the system value. But a further insight from this analysis is the relevance of the covariance terms in equation (5.30) above, and thus the importance of the location-specific production profiles of photovoltaic and wind technologies. This is a major differentiating point from a dispatchable conventional generator, assumed to have a PF of 1, independent of location.

A relevant point is that the impact of the network constraints on a remotely located renewable generator could be mitigated by adjustment of the covariance terms - highlighting the potential benefits of storage technologies. In addition, equation (5.30) shows that the potential exists for wind and photovoltaic generation to increase their respective values, and provides a framework for assessing possible cross-benefits for a particular system.

Equally it should be stated that the production profile PF is the differentiating factor between wind and photovoltaic generation in the determination of the marginal value of a renewable generator as presented in equation (5.30).

Finally, inspection of the β^2 terms show how there is a value for distributed generation on the demand side of transmission constraints, a point particularly relevant to photovoltaics.

5.4.3 Comparison with Value of Dispatchable Conventional Capacity

In order to aid the above development and discussion, for comparison purposes this section assesses the system value of a remotely located dispatchable conventional generator.

Commencing with equation (5.23) and noting that by the model framework $PF = 1$ for a conventional generator gc, the following equation can be written:

$$MV_{gc} = FC_{gc} = \sum_{h=1}^{8760} \left(\lambda_{h,ni} - CVR_{gc} + \mu^3_{h,gc}\right) \tag{5.31}$$

Which can be developed in a similar fashion to the development of equation (5.30) above to arrive at the following equation:

$$\begin{aligned} MV_{gc} = FC_{gc} = H.E(\lambda_{nd}) + H.E(\alpha_{l(ni,nd)}) - FCt_{l(ni,nd)} \\ + 2H.E(\beta^2_{l(ni,nd)}) - H.CVR_{gc} + H.E(\mu^3_{h,gc}) \end{aligned} \tag{5.32}$$

Where $E(\mu^3_{h,gc})$ is the only additional term not described previously. It represents the expected value of the dual variable of the non-negativity constraint of the production variable. Thus it is only non-zero when production of the conventional generator is zero. This will occur when $\lambda_{h,gc} - CVR_{gc} \leq 0$.

There are a number of noteworthy differences between the system marginal value of conventional capacity as expressed here in equation (5.32) and the marginal value of PV or wind capacity as expressed previously in equation (5.30). These differences include: a) the marginal value of the conventional generator is independent of the unit's capacity factor, b) the marginal value of the conventional generator is independent of any covariance patterns between its production and any other variables and c) the presence of the $E(\mu^3_{h,gc})$ term, a term which is difficult to draw conclusions from prior to viewing the optimisation model output.

Under the model framework, conventional generation capacity can be expanded at any node. From the system perspective, the model will invest in conventional generation capacity at a remotely located node in the event that the cost of the importing transmission constraint justifies it relative to the cost of transmission.

From the investor perspective, conventional generation capacity is simply located at the nodes with the highest electricity prices. A similar decision for a renewable generator requires a tradeoff between resource quality and potential revenue.

5.4.4 A Note on Curtailment

One assumption above, and in the analysis of [50], is that due to a renewable generator's economic characteristics, it will always be dispatched to its full available capacity in a given hour (i.e. $\gamma_{h,gr} > 0$). However, this is not necessarily always the case, particularly as penetration of renewable generators increase (as various experiences around the world can testify to). Curtailment can be caused by three interrelated issues - a)inadequate transmission capacity necessitating local curtailment, b) total renewable generation exceeding system demand and c) constraints imposed by the economic and technical characteristics of conventional generators on the system (constraints such as technical minima and ramping constraints that are not included in this model).

(a) and (b) can be represented under this modelling framework by the hours when $\gamma_{h,nd} = 0$, or from equation (5.13), when $\lambda_{h,nd} = CVR_g = 0$. While (a) can be offset by transmission investment (subject to the decision of whether the benefit of doing so exceeds the cost), (b) is a more fundamental limit that in the long term appears to be a barrier to photovoltaic deployment, due to the associated reduction in economic value of the technology.

The hours when (a) occurs will be an output of the optimisation process, and are not known *a priori*. It is apparent that curtailment will likely lead to a more rapid decrease in the marginal value of a renewable generator - the more hours curtailment occurs and the system marginal price is zero, the fewer hours available for the generator to recoup all investment costs. An important point to note is that curtailment will begin to occur at a local level, due to transmission constraints, at lower quantities of installed capacities than would be indicated by models that do not include the transmission network.

5.5 Model Extensions

In addition to the model formulation presented earlier in this Chapter, a number of extensions to the model have been developed. These extensions are of interest to the broader questions of this thesis considered in later chapters.

5.5.1 Renewable Energy Support Mechanisms

As discussed in Section 2.2.3, both price and quantity measures are methods of support for renewable energy. The impact of inclusion of numerous types of supports schemes are now discussed:

RPS

The inclusion of a renewable portfolio standard for production from photovoltaics, gs, in the model would necessitate an additional constraint of the following form:

$$\sum_{h,gs} PTP_{h,gs} \geq RPS. \sum_{h,nd} DMD_{h,nd} \tag{5.33}$$

Where RPS is the fraction of electricity generation that is mandated to be produced by PV generators. Of course, this equation formulation could extend to any technology.

The inclusion of this equation would lead to an additional term in the Lagrangian as follows:

$$+\tau \left(RPS. \sum_{h,nd} DMD_{h,nd} - \sum_{h,gs} PTP_{h,gs} \right) \tag{5.34}$$

Re-writing the adapted equation (5.13), yields the following expression for γ

$$\gamma_{h,g} = \lambda_{h,nd} + \tau - CVR_g \qquad \forall h, g \tag{5.35}$$

This combination then yields the following equation for the marginal value of a PV generator, gs, in a system with a RPS scheme in place:

$$MV_{gs} = FC_{gs} = \sum_{h}^{H} (\lambda_{h,nd} + \tau).PF_{h,gs} \qquad \forall gs \tag{5.36}$$

Feed-in-Tariffs

As mentioned in Section 2.2.3, there are two primary types of feed-in-tariffs - the 'flat' feed-in-tariff and the premium feed-in-tariff. A flat feed-in-tariff can be modelled under the centralised framework of this model as a negative variable cost for the generator to which the feed-in-tariff is awarded. Thus in the case of a PV generator, $CVR_{gs} = -FIT$. This will then adjust the expression for γ to the following:

$$\gamma_{h,gs} = \lambda_{h,nd} - (-FIT) \qquad \forall h, gs \tag{5.37}$$

Yielding the following expression for the marginal value of a PV generator:

$$MV_{gs} = FC_{gs} = \sum_{h}^{H} (\lambda_{h,nd} + FIT).PF_{h,gs} \qquad \forall gs \tag{5.38}$$

This is the same methodology by how a production tax credit would also operate.

It is apparent from inspection of equations (5.36) and (5.38) that under the framework of this model, an RPS and a 'premium-type' FIT will produce the same policy outcome when the feed-in-tariff premium is set to the same level as the dual variable of the RPS constraint. In the real world however, there is a difference among the policies in terms of risks facing the investor - FIT is known a priori while the final value of τ depends on market behaviour.

Both measures work by increasing the marginal value of the generator, making it worthwhile to invest at a higher capital cost of the technology than would be the case without the measures in place.

It should be noted that the flat feed-in-tariff cannot be included directly in a centralised model. Some analytical work is undertaken with a flat feed-in-tariff however in Section 8.5.2.

Cost Reduction / Investment Subsidy

Another possible support measure is to subsidise capital costs (by an investment tax credit for example). Inspecting equations (5.36) and (5.38), it is clear that the solar deployment path by adjustment of the left hand side of the equation or the right hand side of the equation are not equivalent. As regards the right hand side of the equation the feed-in-tariff/RPS means of promotion are directly related to the PF of the PV capacity while reduced costs on the left hand side of the equation are not. This would suggest that RPS/FIT policies will encourage solar generation in the areas of the best resources whereas the path under the cost reduction mode may lead to a different path being followed with a possible shift toward where energy prices are higher.[4] This topic is considered further in Chapter 6.

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[4] A further consideration is that in the long-term, the RPS/FIT could 'buy' cost reductions in the solar technology, leading to a convergence of paths. This level of effect is not captured within this model framework.

5.5.2 Carbon Constraints

Two ways of representing carbon constraints can be included in the model. The first simply involves placing an extra term in the objective function where the total emissions are multiplied by an input carbon price (a carbon tax). The second (a carbon cap) can be represented as follows:

$$\sum_{h,gs} PTP_{h,gs}.e_{gs} \leq E_{max} \tag{5.39}$$

Where E_{max} = a cap on carbon emissions.

Inputting the above equation into the Lagrangian, and following similar analytical development, yields the following expression for the marginal value of a PV generator under a carbon cap:

$$MV_{gs} = FC_{gs} = \sum_{h}^{H} (\lambda_{h,nd} - e_{gs}.\epsilon).PF_{h,gs} \qquad \forall gs \tag{5.40}$$

Where ϵ is the dual variable of the carbon emission constraint.

Noting that $e_g = 0$ for renewable technologies, it can be stated that the carbon emissions will not directly affect the marginal value of the renewable generator. However, the price on carbon will indirectly lead to an increase in system nodal prices, increasing the marginal value of a renewable generator.

Before leaving this topic, and considering the emphasis placed on locational effects in this model, mention should be made of the concept of marginal carbon intensities, as presented by [79]. It is not discussed further here, but the concept is that due to network effects the marginal carbon intensity of a unit increase in demand varies both temporally and spatially, with associated implications if carbon emissions reductions are a primary goal.

5.5.3 Role of Underlying System

To date this discussion has focussed on the optimum design of a new electricity system designed from scratch based on a static annualised optimisation framework. However, except for certain regions of the developing world, all geographic areas contain some existing underlying electricity network. This section then outlines how the underlying system influence the equations and discussion above.

With existing generation capacity included, equation (5.3) becomes:

$$PTP_{h,g} \leq (PTI_g + DTGT_g)PF_{h,g} \qquad \forall h, g \tag{5.41}$$

Where $DTGT_g$ is the existing capacity of a generator of technology g

Similarly, equations (5.4) and (5.5), with existing transmission capacity included, can be expressed as follows:

$$\left|FLE_{l(ni,nf)}\right| \leq TTC_{l(ni,nf)} + FLMX_{l(ni,nf)} \tag{5.42}$$

Where $FLMX_{l(ni,nf)}$ is the exising capacity of a transmission line from ni to nf.

Inspection of the above equations indicates that the input of these new terms into the Lagrangian will not affect the structure of the optimality conditions. However, the inclusion of the underlying capacity can be expected to change the quantities of investment required to get to the same optimal equilibrium point. The optimal generation investment at some nodes or transmission investment between nodes may now be zero, requiring the introduction of the μ terms into the marginal value calculations.

Finally, it should be noted that under this framework, retirements of existing generation capacity are not considered. When existing capacity is included in this model framework the only capacity that can be displaced by renewables is the counterfactual capacity that would have been installed if the renewable generator was not brought onto the system.

5.5.4 Concentrating Solar Power

As discussed previously, from the perspective of a power system, the characteristics of electricity from concentrating solar power looks very different to the characteristics of electricity from photovoltaics. For inclusion in the model, CSP is assigned a $PF = 1$, subject to the following additional constraints on the quantity of energy collected from the sun:[5]

- Energy collected in each hour[6] in each day minus production in that hour equals

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[5] Equations (5.43) to (5.45) were adapted from the formulation of the MEMPHIS model, developed by Professor Andrés Ramos at IIT, Madrid

[6] Adapted from [74].

storage in minus storage out:

$$(2.PTI_{gcsp}).\frac{DNI_{d,h,gcsp}}{DNI_{ref}} - PTP_{d,h,gcsp} = storin_{d,h,gcsp} - storout_{d,h,gcsp} \qquad \forall d,h,gcsp \tag{5.43}$$

- The storage level in each hour of the day is less than the storage in the previous hour plus (minus) the net storage in (out) in that hour:

$$0.95stor_{d,h-1,gscp} + storin_{d,h,gcsp} - storout_{d,h,gcsp} \geq stor_{d,h,gcsp} \qquad \forall d,gcsp,h\exists h>1 \tag{5.44}$$

- The storage level in any particular hour is less than the storage capacity of the facility

$$stor_{d,h,gscp} \leq 6PTI_{gcsp} \qquad \forall d,h,gcsp \tag{5.45}$$

Where d is the day, $DNI_{d,h,gcsp}$ = Direct Normal Insolation in hour $h(d)$ at the location of $gcsp$, DNI_{ref} is the reference insolation value - a design parameter for the facility, $storin_{d,h,gcsp}$ is the energy input to storage in hour $h(d)$, $storout$ is the opposite, and $stor$ is the actual level of stored energy at hour $h(d)$.

It may be noted that these equations 'hard-code' three design decisions: a) the field collector area - here assumed to be sized as to collect the equivalent of double the turbine capacity in every hour, b) the size of the storage - assumed to be 6 hours of storage, and c) thermal losses in storing energy from one hour to the next. A perhaps optimistic 0.95 loss factor was used.

5.5.5 Transmission Losses

The following constraint is added to linearise losses as follows:[7]

$$L_{h,l(ni,nf)} \geq 2\left|V_{l(ni,nf)}\right|\left|V_{l(ni,nf)}\right| \frac{R_{l(ni,nf)}}{R^2_{l(ni,nf)} + X^2_{l(ni,nf)}} \left[m(TT_{h,ni} - TT_{h,nf}) + n\right] \tag{5.46}$$

Where $L_{p,l(ni,nf)}$ are the losses in line $l(ni,nf)$ in hour h, $R_{l(ni,nf)}$ is the resistance of the line $l(ni,nf)$, and m and n are input parameters designed to linearise the relevant cosine.

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[7] Method of linearising losses obtained from MIT IAP 2010 course ESD.940 - in particular lectures of Dr. Javier García González

In the later application of the Expan model (Chapter 6), 8 linear segments are used to approximate the cosine. In addition, the final component of including the losses requires $\frac{L_{h,l(ni,nf)}}{2}$ to be added to the demand at both nodes ni and nf.

5.6 Comment on Centralised Optimisation Framework

This is a model that optimises from the point of view of a centralised system operator / planner. The electricity sector in many parts of the world however functions under a market regime. A market model should theoretically produce the same outcome as the optimal centralised approach. It is thus the market overseer / regulator's job to ensure that the market is structured in such as way as to produce the social optimum result, a result which could be represented by a centralised model such as Expan. The regulatory implications outlined later in this document will discuss the regulatory actions that may be required in order that the market and centralised optimum results align.

5.7 Chapter Summary

The following items summarise the contents of this chapter:

- The basic formulation of the cost-minimisation model developed and utilised for this thesis was presented.
- In order to overcome potential 'black box' effects of model results, how the model makes decisions was investigated and discussed. Essentially, the model invests until such point as the marginal benefit equals the marginal fixed cost of new generation or transmission capacity.
- To understand what implications are associated with solar power deployment, it was decided that it would be useful to first understand how network constraints impact on the value of solar power.
- Transmission constraints were shown to cause the cumulative nodal marginal benefit to decrease at a faster rate than the system benefit in a world without transmission constraints. Thus the quantity of capacity where the MB equals the MC is at a lower point. The cost of transmission drives this.

- Considering the above point, a framework was developed to consider the impact of transmission on the value of a remotely located renewable generator, given the particular technical and economic characteristics of these generators. The primary factors in the marginal value calculation consisted of a number of fixed terms and a series of terms relating to the covariance between the pattern of renewable generation and the pattern of when transmission constraints are binding.

- A number of extensions were developed from the base model, including concentrating solar power, renewable electricity support mechanisms, carbon constraints, and transmission losses.

- Inspecting the support measure formulations, it was shown how different types of policy could lead to varying deployment paths for photovoltaics.

- This analysis has highlighted that in a world with many renewable generators, locational effects are more important than in a traditional well-meshed network with controllable conventional technologies. The importance of locational signals in efficient solar power deployment is discussed in detail later in the document.

In order to expand upon the general findings of this chapter, it is necessary to apply reasonable numbers to the developed expressions. The next chapter of this thesis thus applies this model to a simplified representation of a real power system, using real historic and projected data in an attempt to provide a reasonable assessment of the implications of the tradeoffs outlined in this section.

Chapter 6

Expan Model Results

6.1 Application of Expan Model to ERCOT Systems

In order to expand upon and use the Expan model analytically developed in the previous chapter to answer the broader questions of this thesis, the model is applied to a simplified representation of the ERCOT power system.

6.1.1 Representation of the ERCOT Power System

While the model outlined in the previous chapter could be applied to any power system, or to an abstract stylised model of a power system, it was decided to apply the model to the Electricity Reliability Council of Texas (ERCOT) power system. There were numerous reasons behind this decision: a) ERCOT is an isolated power system, not currently connected to the Eastern and Western Interconnects which account for the remainder of the 'Lower 48' states power systems. This isolated nature allows for effects to be studied within a more controlled environment. b) Being a part of the United States, quality data for the ERCOT system were available. c) Substantial wind and solar resources exist within the ERCOT footprint, with the greatest quality resources located in remote areas away from traditional transmission corridors, allowing the locational issues discussed in Chapter 5 to be considered numerically.

Computing limitations lead to tradeoffs in what simplifications are implemented in the application of the Expan model to the ERCOT power system. Expansion models typically optimise over a limited number of representative dispatch periods (Section 4.1). In this the-

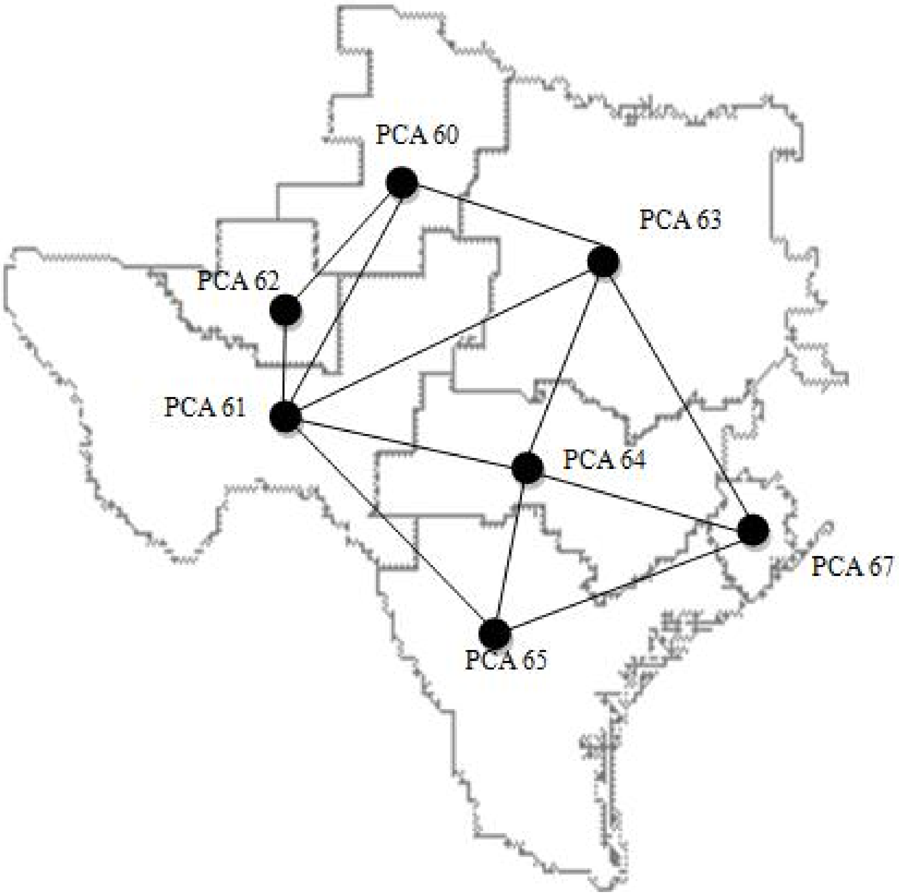

Figure 6-1: Schematic Diagram of ERCOT System Representation

sis however, considering the interest in renewable energy sources, it was decided to include 8760 dispatch periods. A tradeoff of this strong temporal resolution is the requirement to have a weaker geographical resolution. Thus rather than including the more than 4000 nodes of the ERCOT system, 7 representative nodes of the ERCOT system are included. While this is a large simplification, it is an effort to provide insight into network impacts that would not be included in the consideration of a single node system. A graphical representation of the system modelled is shown in Figure 6-1. The boundaries of the 7 areas shown here are largely based on the Control Areas of former vertically integrated electricity utilities in the State of Texas. Following from this geographic simplification is a simplification of the representation of transmission lines, where each transmission line represents a gross aggregate of the transmission capacity from area to area.

The work in breaking down the system into these components was done at the National Renewable Energy Laboratory, and applied in the ReEDS model, from which much of the

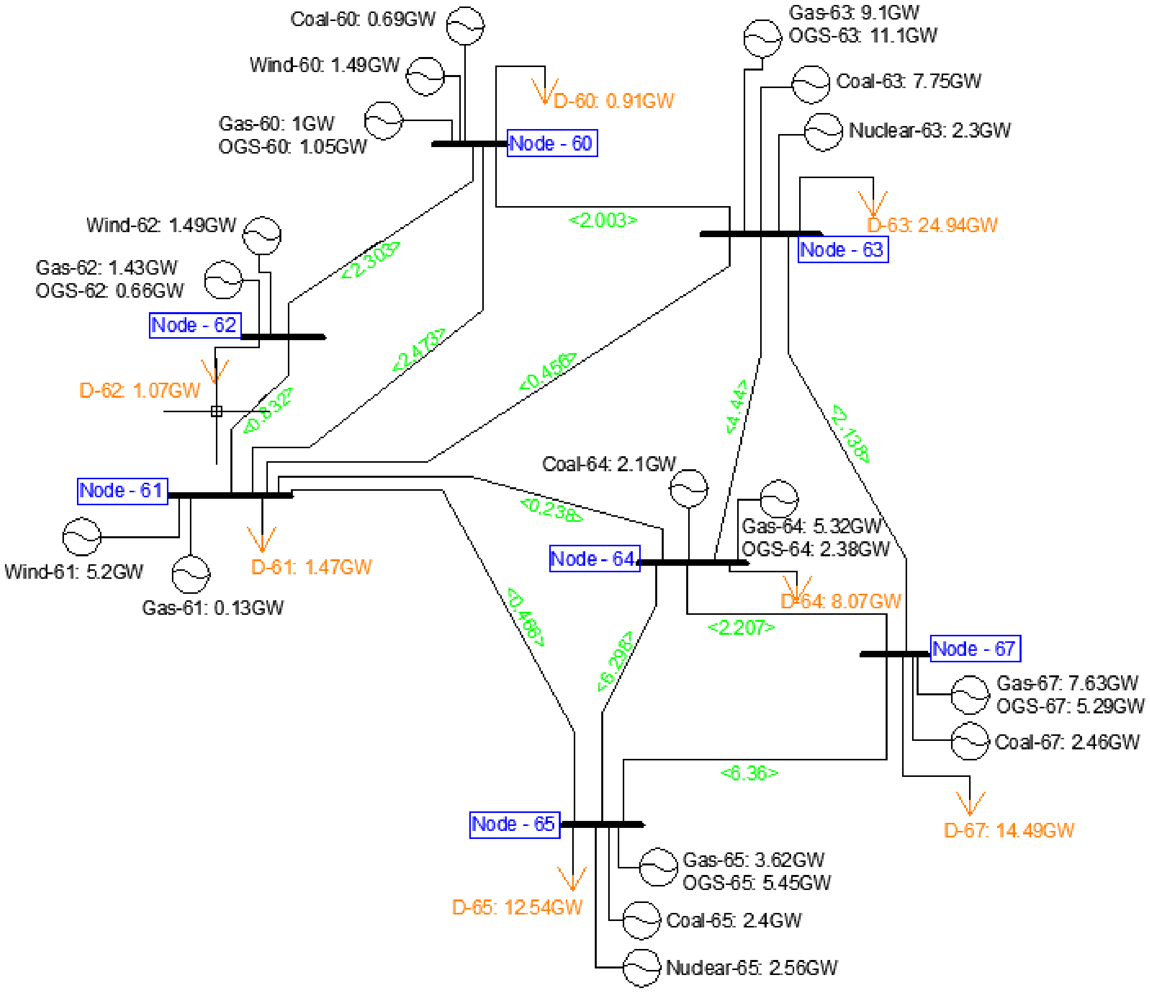

Figure 6-2: Diagram Representing Existing ERCOT System as per Model Inputs
'Power transfer capacity' of each line represented in <>, demand corresponds to 2009 peak demand data, and generation corresponds to existing generation capacity

underlying data here is drawn.

The combination of this information is represented in the diagram of Figure 6-2 with information on the distribution of the underlying solar resource presented in Table 6.1.

6.1.2 Limitations of Expan model

The model as described in Chapter 5 does not include the following (non-exhaustive list of) aspects of power systems: discrete investments in generation capacity and in particular transmission capacity, capacity retirements, ramping constraints, uncertainty, a reserve margin, operating reserves, contingency constraints, the relevance of wholesale prices versus retail prices and distribution networks & associated issues. The static optimisation formu-

Table 6.1: Solar Resource Information for ERCOT System (as applied in Expan model)

Location	$\sum_{h=1}^{8760} PF_{h,gs}$
Node 60	1843
Node 61	1967
Node 62	1930
Node 63	1692
Node 64	1727
Node 65	1721
Node 67	1733

lation of the model is missing the sequential, iterative nature of real world decision making. Relative costs drive the model outcomes but are subject to many assumptions about future developments. Different components of the electricity system take different lengths of time to construct, also not reflected in this model. The representation of the transmission network is a significant simplification. Also, outages of conventional generators are not included which is somewhat of an artificial advantage to conventional generation.

An issue to note in the modelling work is the potential to miss some effects due to the different data sources used. Solar insolation data is for the historical year of 2005, while wind and demand data are derived from future production profiles developed by ERCOT. Thus some of the correlations between demand, solar and wind production that are of interest may not be properly captured due to the data sources chosen.

Also, assumptions are made in the transfer of data of differing geographic resolutions to that appropriate to the Expan model implementation. This is a possible source of error. For example, the insolation profile for each of the 7 nodes is represented by the insolation profile of one 10km x 10km grid square - this may be penalising for solar power as the benefits of geographic diversity across a region (as mentioned in Section 2.2.4) may not be accounted for adequately. However, the addition of insolation data from more grid squares would necessitate somewhat arbitrary assumptions about the distribution of solar power capacity within each nodal region. The wind profiles have been derived from actual predicted future wind production profiles and were aggregated and normalised by node. Demand disaggregation ratios amongst the nodes have been taken directly from the ReEDS model.

The model searches for a cost-minimising optimal solution and the results discuss insights gained from various optimal solutions across different inputs. An inherent assumption is contained here about the values of society, however the provision of electricity at least cost appears to be a reasonable paradigm to follow.

A Note on Reserve Margin

Ensuring resource adequacy is a vital component of the management and planning of power systems. Thus expansion models such as those discussed in Section 4.1 typically include a reserve margin constraint. It is thus worthwhile to discuss why a reserve margin constraint is not included in the base version of the Expan model. The primary reason a reserve margin constraint is not included is the difficulty in assigning a valid capacity credit to wind or solar power within the linear model framework. As [60] outlines, assigning a capacity credit to solar generation is non-trivial and depends on a number of factors including the resource profile of a particular area, and of particular relevance here, the quantity of installed solar power capacity (an endogenous variable to the model). The ReEDS model addresses this issue by updating the capacity credit at each optimisation timestep as wind and solar power is deployed. This option is not available in a static optimisation model.

Considering the deterministic nature of the model however, an implicit reserve margin is in place, with a value of 1.0. This stems from the load balance constraint, where the capacity must be in place in each hour so that production can meet demand. This results in a very ‘tight’ system at the optimal solution.

6.1.3 Implementation of Model

The Expan model was implemented in the GAMS optimisation software environment [80], and solved using the CPLEX solver’s interior point method [81]. Model results were output via GDX file to MATLAB, where the figures of interest were produced. A significant portion of the preparation of this thesis involved the refining of the relevant code to undertake the above tasks. Appendix A includes the primary code of the Expan model as applied to photovoltaics. Appendix B presents a sample of the MATLAB code developed to produce the figures as shown later in this chapter.

6.1.4 Data

The primary sources of data used in the application of the Expan model are as follows:

- Demand data for the year 2009 in the ERCOT system from the ERCOT planning and operations website [82].

- Annual average aggregate ERCOT load growth factor from 2009 to 2019 (2% per annum) [82]. This figure was extrapolated to 2030 - the static optimisation year considered in this model.

- The wind production profile for 2018 ERCOT system was obtained from [82] and normalised to represent the production profile (i.e. PF) of any existing or new wind power capacity at each node.

- Solar radiation data was obtained from the National Solar Radiation Database (NSRDB) [83]. Information on the database is provided in [84].

- Technology cost data was obtained from EIA and NREL as per Table 2.1.[1]

- The underlying system generation and transmission capacity was obtained from the ReEDS model [65].

- Current installed wind capacity in ERCOT system - 8,916MW [85].

- Transmission cost data comes from Table 9.1 of [86].

- The annualised capital charge is assumed to be 10% of overnight capital cost

6.2 Numerical Application of Chapter 5 Development

Prior to using the Expan model to address the broader questions of the thesis, the findings of Chapter 5 are validated with the application of the model to the ERCOT system. The purpose of this exercise is to a) present some illustrative model results and b) illustrate with an example the discussion of the previous chapter in relation to the marginal system value of a renewable generator under network constraints.

For the purposes of this discussion, 4 cases were selected to expand upon the analytical development and subsequent discussion of the previous chapter: a) a base case with no

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[1] OGS (‘Oil-Gas-Steam’) is an additional technology option included in the Expan model whose costs are not included in Table 2.1. Its variable cost of production is 55.25$/MWh, thus it represents the role of a peaker in the Expan model. As it represents a dated technology, no new installations are allowed, and thus no capital cost was input.

Table 6.2: New Generation Capacity across 4 Illustrative Cases

Generator	Base Case GW	RPS Case GW	Reduced Cost Solar Case GW	Reduced Cost Solar and Transmission Case GW
Solar-61	0	1.809	2.351	7.511
Solar-62	0	6.378	2.951	3.27
Solar-63	0	0	0.816	0
Solar-60	0	0	0	6.576
Solar-64	0	0	1.738	0
Solar-65	0	0	0.816	0
Gas-60	0	0	0	0.024
Gas-61	1	0	0	0
Gas-62	0	0	0	0.019
Gas-63	1.192	0	0	0
Gas-64	0	0	0	0.196
Gas-65	0	0	0	0.084
Gas-67	0	0	0	0.025
Coal-60	0	0	0	2.61
Coal-63	0.803	0	0	2.145
Coal-64	5.185	5.668	5.292	3.131
Coal-65	4.414	4.179	4.972	2.976
Coal-67	6.388	5.779	5.257	2.939

renewable energy incentives, b) a case where the relative capital cost of photovoltaics is reduced, c) a similar case to (b) but with transmission costs reduced to an extent where there are effectively no transmission constraints within the system, and d) a case including one of the model extensions - an RPS scheme to support solar energy. The RPS has been implemented such that the same quantity of photovoltaic electricity is generated as is generated in case (b).

6.2.1 Comparison of 4 Illustrative Cases

Generation Capacity Investment

As mentioned previously, the model invests in new capacity of a particular technology at a node to such a point where the marginal cost equals the marginal benefit of doing so. If marginal benefit is less than marginal cost, no investment is made. Table 6.2 shows the quantities at which this point is reached for each technology across the four chosen illustrative cases.

Considering Table 6.2, it is clear that the magnitude and distribution of the deployment of photovoltaics varies across the scenarios. In the reduced PV cost case, PV technology is invested in on a distributed basis across the system nodes despite the varying quality of the solar resource across the system. In the case where transmission is not binding in the model there are two noteworthy points: a) the overall magnitude of PV capacity installed is greater and b) the PV capacity is concentrated in the western nodes of 61, 60, and 62, where the quality of the solar resource is highest (Table 6.1). At the first order, this is simply a result deriving from the statement that transmission capacity costs money, however the second order effects as will be outlined below show that simply adding a cost to solar in expansion models to account for associated transmission costs would miss some relevant and useful effects.

As the RPS case has been designed so that PV generation equals that of the cost reduction case, it is worth comparing in particular these two cases. Under the RPS case the new PV capacity is concentrated in the higher solar resource quality nodes of 61 and 62, and associated transmission in constructed. This differs from the distributed profile of the cost reduction case. The reason for this difference is that relative to the cost of an RPS forcing expensive photovoltaics onto the system, the cost of transmission is low. In the case where the cost of photovoltaics decreases however, the cost of transmission is expensive relative to the decreased cost of the solar capacity, and thus the model builds the PV capacity at locations requiring less transmission but with poorer resources. The explicit mechanisms of these results are discussed below.

This table highlights that the path of photovoltaics deployment, with associated implications for power systems, will vary depending on whether it is policy driven (with the type of policy important) or cost reduction driven.

Finally, no new wind energy capacity is installed in any of the scenarios, with the incentives for wind generation that exist in the real world not included in the model base case. It should be noted however that the existing system with its current installed wind capacity has a role in the capacity investments shown here. For example, there are significant quantities of existing wind generation capacity installed within the node 61 area, which influences the extent that the quality solar resource is utilised within the node 61 area.

Table 6.3: New Power Transmission Capacity across 4 Illustrative Cases

Line	Base Case *GW*	RPS Case *GW*	Reduced Cost Solar Case *GW*	Reduced Cost Solar and Transmission Case *GW*
$l(60,63)$	0.763	1.667	1.197	9.076
$l(61,62)$	0	2.266	0.52	3.926
$l(61,63)$	1.396	2.027	1.763	4.51
$l(61,64)$	0.41	0.822	0.54	6.056
$l(61,65)$	0	0.249	0.076	5.699
$l(63,67)$	0	0	0	2.728
$l(64,67)$	0	0	0	2.197

Transmission Capacity Investment

Table 6.3 presents the transmission capacity expansion results for the four illustrative cases. As shown previously in equation (5.20), the model builds transmission until such point as the cumulative quantity of the transmission constraint dual variables is equal to the marginal cost of one additional unit of capacity. Thus when the cost of an additional unit of transmission capacity is infinitesimal as in the 'reduced cost solar and transmission' case, significant transmission capacity is constructed as the model builds transmission until the cost of the transmission constraint is equally small. In the reduced solar cost case, with standard transmission costs, the model constructs new transmission capacity to accommodate the lower cost solar energy, but not to the same degree as it does to meet the RPS requirements at the higher cost for photovoltaic capacity. In the base case, with no solar investment, it is noteworthy that transmission capacity is constructed from the western nodes to the rest of the system. This aligns with what is occurring in the ERCOT system currently - new transmission capacity is under construction to ease transmission constraints that currently impact upon the wind generation capacity that has been installed in western Texas in recent years.

6.2.2 Marginal System Value of a Remotely Located Renewable Generator

Recalling equation (5.30), what determines the marginal system value of a remotely located renewable generator[2] is now numerically explored. This equation is applied to both PV and

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[2] A renewable generator as discussed here again refers to photovoltaic or wind capacity.

wind generation capacity at node 61. This western node contains the best solar resources in the ERCOT region in addition to strong wind resources. The results across the three illustrative cases are presented in Tables 6.4 and 6.6. Node 64 was chosen as the 'system' node, as it a) is connected to node 61 by a transmission corridor and b) contains a contributing baseload generator, coal-64, whose cost properties can be used to represent the expected value of the system marginal price of electricity.

The terms in this equation can be broken down by values known *a priori*, expected values which are a result of the optimisation process, and covariance values dependent on the pattern between the production of the renewable generator and various dual variables. The values known *a priori* are:

- $E(\lambda_{64})$: As shown by Lamont [50], $\sum_{h=1}^{H} \lambda_{h,64} = FC_{coal64} + \sum_{h=1}^{H} CVR_{h,coal64}$, which can be determined from the model input data, and in the case here equals $\$51.556/MWh$.
- CF_{gr61}: The capacity factor of the renewable generator $gr61$ at the remote location is represented by the expectation of the generators PF over the 8760 hours, which can be determined from historical profiles. For the profiles used in this example, $CF_{solar61} = 0.222$ and $CF_{wind61} = 0.417$.
- $FCt_{l(61,64)}$: The fixed cost of a unit of capacity along a transmission corridor, which is input data to the model.

The remaining terms were introduced and discussed in Section 5.4, and the output values are discussed below.

Example 1: PV Capacity at Node-61

Focussing on the PV generator, solar-61, Table 6.4 shows the breakdown of the various components of the marginal value of the generator across cases (a), (b), and (c). As indicated by [50], the value of $H.E(\lambda_{64})$ held constant across the three cases. $H.E(\alpha_{l(61,64)})$ had a negligible influence while the non-negative value of the term $2H.E(\beta^2_{l(61,64)})$ indicates that there are occasions when node 61 is importing power from node 64 that the transmission constraint is binding and that the PV generator would provide some value in locating the 'demand' side of the constraint. However, this value is offset by both the fixed cost of transmission between the nodes, and whether the PV generator produces when β^2 is active.

Moving on to the covariance terms, it is clear from the table that the covariance terms play an important role. Comparing the $Cov(\lambda_{64}, PF_{Solar-61})$ term across the three cases provides some insight. At zero penetration, the value of a PV generator is increased by the covariance between the system nodal price and its production factor. As the penetration increases, this term decreases. In the absence of transmission costs, and increased quantities of PV capacity, the covariance has changed to a negative value.

Considering the term $H.Cov(\beta^1_{l(61,64)}, PF_{solar-61})$ portrays how, at zero penetration, the first PV generators provide system value by producing at times not aligned with when the transmission constraints are active (due to negative covariance). At higher penetrations however it is the exporting PV capacity that is causing the transmission constraint to bind and thus there is a positive covariance between PV production and the primary constraint on transmission, reducing the value of the PV generator.

Similarly, the term $H.Cov(\beta^2_{l(61,64)}, PF_{solar-61})$ further shows how the value of PV capacity changes with increasing solar power deployment. In this case, the first generator provides value by somewhat offsetting transmission constraints affecting power incoming to the node. However, with increasing PV generation, the covariance with the occasions when this constraint is active becomes negative, leading to a reduction in the marginal value of the PV generator.

As regards the $H.Cov(\alpha_{l(61,64)}, PF_{solar-61})$ term, this term can vary depending on various system circumstances, with little general insight to be provided. However, as noted previously, the model has been set up so that it will not have a large influence.

Table 6.4 thus shows in detail the mechanisms of how transmission constraints influence the value of a PV generator, with the relative patterns being important components. The table also provides insight into how the model makes decisions about what system components to invest in.

Table 6.5 shows the results of the same terms for the RPS case, with the inclusion of an additional term - the contribution of the dual variable of the RPS constraint (the equivalent to a renewable energy certificate) to the value of the generator. The additional PV capacity at node 61 has led to a reduction in the marginal value of PV at that node (net of the additional RPS term that boosts the overall value). This is primarily due to a decrease in the covariance between the generator's production and the 'system' price and an increase in the covariance between the generator's production and cost of the binding transmission

Table 6.4: Marginal Value of PV Capacity at Node 61 under Transmission Constraints

	Base Case	Reduced Cost Solar Case	Reduced Cost Solar and Transmission Case
	$M\$/GW$	$M\$/GW$	$M\$/GW$
$FC_{Solar-61}$	269.94	89.849	89.849
$MV_{Solar-61}$	108.602	89.849	89.849
$+H.E(\lambda_{64}).CF_{Solar-61}$	100.364	100.364	100.364
$+H.Cov(\lambda_{64}, PF_{Solar-61})$	10.285	1.074	-10.515
$+H.E(\alpha_{l(61,64)})$	-5.01E-14	0.006	0
$+H.Cov(\alpha_{l(61,64)}, PF_{Solar-61})$	-0.492	-1	0
$-FC_{l(61,64)}.CF_{Solar-61}$	-5.266	-5.266	0
$-H.Cov(\beta^1_{l(61,64)}, PF_{Solar-61})$	-(-2.629)	-6.157	0
$+2H.E(\beta^2_{l(61,64)}).CF_{Solar-61}$	0.873	1.203	0
$+H.Cov(\beta^2_{l(61,64)}, PF_{Solar-61})$	0.208	-0.373	0

constraint.

Table 6.5 thus shows the underlying mechanism of how a common form of renewable energy support scheme, an RPS, meets its goals.

Example 2: Wind Capacity at Node-61

Before focussing on the marginal value of the wind generator at node 61 in detail, it should be noted that, while no new wind capacity is constructed under the three scenarios considered, there is a significant quantity of existing wind capacity in the system (circa 5.2GW at node 61), that will influence the results here.

Inspecting Table 6.6, a number of points stand out: a) the high value of the negative covariance between the nodal price at node 64 and the production pattern of the wind generator, and b) increased PV deployment between the cases on the left of the table leads to a slight increase in the marginal value of the wind generator. This latter effect can be largely attributed to a change in the $H.cov(\beta^1_{l(61,64)}, PF_{wind61})$ term, as the PV generator has likely shifted the times when the β^1 constraint is active, thus reducing the wind generators covariance with it. This may be an indication of further cross-benefits that may be possible when thinking about wind and solar generation. Finally, point (c) is that the difference in the marginal value between the two columns on the right of the table explicitly show how the cost of transmission impacts upon the value of a wind generator.

Table 6.5: Marginal Value of PV Capacity at Node 61 (3.7% RPS case)

	RPS Case
	$M\$/GW$
$FC_{Solar-61}$	269.94
$MV_{Solar-61}$	269.94
$H.\tau.CF_{Solar-61}$	190.116
$MV_{Solar-61}$(Net RPS)	79.824
$+H.E(\lambda_{64}).CF_{Solar-61}$	100.364
$+H.Cov(\lambda_{64}, PF_{Solar-61})$	-4.395
$+H.E(\alpha_{l(61,64)})$	0.36
$+H.Cov(\alpha_{l(61,64)}, PF_{Solar-61})$	-0.584
$-FC_{l(61,64)}.CF_{Solar-61}$	-5.266
$-H.Cov(\beta^1_{l(61,64)}, PF_{Solar-61})$	-10.678
$+2H.E(\beta^2_{l(61,64)}).CF_{Solar-61}$	0.045
$+H.Cov(\beta^2_{l(61,64)}, PF_{Solar-61})$	-0.022

Table 6.6: Marginal Value of Wind Capacity at Node 61 under Transmission Constraints

	Base Case	Reduced Cost Solar Case	Reduced Cost Solar and Transmission Case
	$M\$/GW$	$M\$/GW$	$M\$/GW$
$FC_{Wind-61}$	204.98	204.98	204.98
$MV_{Wind-61}$	131.9	134.919	150.972
$+H.E(\lambda_{64}).CF_{Solar-61}$	188.451	188.451	188.451
$+H.Cov(\lambda_{64}, PF_{Wind-61})$	-36.51	-36.8	-37.479
$+H.E(\alpha_{l(61,64)})$	-9.41E-14	0.011	0
$+H.E(\alpha_{l(61,64)})$	0.367	0.574	0
-$FC_{l(61,64)}.CF_{Wind-61}$	-9.889	-9.889	0
-$H.Cov(\beta^1_{l(61,64)}, PF_{Wind-61})$	-11.448	-8.696	0
$+2H.E(\beta^2_{l(61,64)}.CF_{Wind-61})$	1.639	2.258	0
$+H.Cov(\beta^2_{l(61,64)}, PF_{Wind-61})$	-0.711	-0.99	0

6.2.3 Further Consideration of Wind/Solar Interaction

The previous example highlighted how the deployment of photovoltaics on the system led to a slight increase in the marginal system value of wind capacity. It is challenging to consider whether the effect is complimentary due to strong existing presence of wind in the system. Two approaches were attempted - one considered the value of a unit of PV capacity at node 61 with no existing wind generation capacity and one considered the value of a unit of wind capacity with half the existing wind generation installed. In both cases, the value of PV capacity slightly increased in the runs where the existing capacity of wind was *reduced*. In addition when running cases with the cost of PV reduced, more quantities of PV were installed when the wind generation was not there, indicating competition between the two technologies. However, these findings are not generalisable as a portion of the existing transmission capacity serving node 61 may have been developed for wind, transmission which then increases the value of PV when the wind is removed.

It is clear that on one hand, the technologies can compete, and on the other, we have seen PV can increase wind power's value. Again, it is difficult to generalise from these system-specific results, however it is clear that considering the two technologies together when planning a system could provide system benefits.

So while a systematic study is challenging, particularly bearing in mind the limitations of the data, assessing the correlation between wind and PV hourly available production in the ERCOT system does provide some insight (Table 6.7). Note that the correlation coefficient is defined as the covariance divided by the product of the two variables standard deviations. A value of zero indicates linear independence, while 1 indicates full positive dependence and -1 indicates full negative dependence.

Inspecting Table 6.7 indicates a definite negative correlation but not a completely complementary correlation. It is unlikely that using datasets from different years would produce vastly different results. This indicates that there is some potential for synergies between wind and photovoltaic generation - but synergies that are far from a complete solution to dealing with resource variability.

Table 6.7: Correlation Between PV Production Factor and Wind Production Factor
Data for ERCOT system

	wind-61	wind-62	wind-60
solar-61	-0.247	-0.219	-0.224
solar-62	-0.255	-0.226	-0.234
solar-63	-0.231	-0.202	-0.209
solar-60	-0.244	-0.215	-0.225
solar-64	-0.238	-0.209	-0.216
solar-65	-0.254	-0.227	-0.232
solar-67	-0.23	-0.203	-0.208

Table 6.8: Marginal Value of Gas Capacity at Node 61 across 3 Illustrative Cases

	Base Case	Reduced Cost Solar Case	Reduced Cost Solar and Transmission Case
	$M\$/GW$	$M\$/GW$	$M\$/GW$
FC_{gas-61}	108.76	108.76	108.76
MV_{gas-61}	108.76	107.517	108.76
$H.E(\lambda_{64})$	451.63	451.63	451.63
$H.E(\alpha_{l(61,64)})$	0	0.026	0
-$FC_{l(61,64)}$	-23.698	-23.698	0
$+2H.E(\beta^2_{l(61,64)}$	3.929	5.411	0
$-H.CVR_{gas-61}$	-363.54	-363.54	-363.54
$+H.E(\mu^3_{gas-61})$	40.439	37.687	20.67
New Capacity	1	0	0

6.2.4 Comparison with Conventional (Gas) Capacity

In order to provide some context to the above results, and highlight how issues are different for a renewable generator compared to a conventional generator, numbers are applied to equation (5.32) for the same three cases as in Table 6.4 and are presented in Table 6.8.

Comparing the left-hand-side cases, it is clear that the decrease in value is driven by the μ term, which is active when gas production is at a level of zero at the node in question. This is an outcome of the optimisation process, dependent on what other technologies are invested in, what transmission capacity is constructed, what generation the model chooses to dispatch in the event of a tie, and it is thus difficult to compare across cases. The primary point to take away is that, unlike renewable generators, patterns and covariance terms do not have an effect on the value of the conventional generator. In addition, conventional generation can choose to locate where the energy prices are highest and unlike renewable generators, large-scale transmission investment is generally not as necessary in order to sell their product in the electricity market.

6.2.5 Qualification

Choosing a different transmission corridor to undertake this analysis (and associated 'system node') can lead to a different distribution among the values of the terms above, despite achieving equivalent total results (for example considering the 61 - 63 corridor leads to zero values for the β^2 terms and a slightly higher influence for the α terms).

A further qualification about this framework, and an identified weakpoint, is that the focus on a single transmission corridor misses some important network effects. For example, in the RPS case above, a slight majority of PV capacity is installed at node 62. The power generated is transferred through the system toward both node 60 and 61. Thus solar generation takes advantage of capacity constructed through the system (while also being subject to constraints through the system), as opposed to being solely dependent on a single path to the next node. It is conceivable that the framework of equation (5.30) be extended to incorporate multiple transmission lines, however the utility of this approach is an open question, deriving from whether the utility extends beyond the provision of insights from a relatively simple equation.

6.2.6 Discussion

In this section, we have:

- Applied realistic numbers to the theoretical model developed in the previous chapter and verified that the subsequent results are consistent with the analytical development.

- Numerically investigated the mechanism of how transmission constraints reduce the quantity of solar energy at which the marginal cost equals the marginal benefit of an additional generator. This process explicitly shows what implicitly makes sense - transmission costs have an impact, and the various patterns of production of renewable generators can offset or aggravate this impact.

- The cases of wind and gas capacity were compared to the PV results. For the example considered, PV slightly increased the value of wind while the opposite occurred under a non-generalisable additional example. How conventional generation is not subject to the same locational constraints as wind or solar power was highlighted by the gas example.

Subsequently, the following points can be made:

- Under network constraints, the optimum distribution of reduced cost photovoltaics is more dispersed than solely where the best quality resources are. In an RPS case, the PV development is more concentrated.

- What drives the influence of transmission constraints on the marginal value of a renewable generator are two primary factors: a) the cost of transmission and b) the pattern of production of the renewable generator. If transmission was not costly, network constraints would not be an issue and could be overcome by building the required transmission. The β terms would be close to zero and would not be important. However, building transmission does cost money so the focus can be on the second factor, the covariances between the production pattern of the renewable generator and dual variables of the transmission constraints. This highlights how adjusting the relative covariances could have system benefits. Potential methods of adjusting the covariances include co-generation at remote nodes, energy storage at the remote nodes, concentrating solar thermal power technology (with storage) at the remote nodes, variety in the tilts of PV panels, in addition to the consideration of how in certain locations wind and solar may be able to complement each other. Essentially, greater utilisation of a transmission line investment decreases the cost of that investment.

While this section has shown some examples, the absolute value of these effects will vary from power system to power system depending upon the respective wind and solar potential production profiles, in addition to the nature of the underlying system. What this example and discussion does provide is a way to think about the interactions, while also highlighting how relevant they are to outcomes.

6.3 PV Deployment Results

Applying the insights gained previously of how the model chooses the cost-minimising quantities of generation capacity investment, transmission capacity investment and associated optimal dispatch, this section of the thesis considers some broader implications of photovoltaic deployment on electric power systems. The implications considered are categorised as following:

- Investment in generation and transmission
- Dispatch
- Carbon emissions
- Cost structure of system / Pricing of system

The approach followed has been to run the Expan model across a series of cost scenarios, and subsequently compare the results of the static optimisation process as the capital costs of the photovoltaic technology decline. In addition, a series of runs have been undertaken with a gradually increasing solar-specific RPS standard, and differences- (and similarities-) of-note will be highlighted when they exist between the two approaches. Where relevant, the potential influence of a carbon price will also be discussed in the context of these results.

In conducting the following suite of results, two constraints were placed on the system additional to the constraints in place in the illustrated model runs of the previous section of this chapter - a) the inclusion of transmission losses and b) the inclusion of a network reliability constraint - a transmission security factor of .75, that restricts power flows to 0.75 of named corridor capacity. In the RPS case below, the transmission losses constraint was turned off. This was to prevent the model from generating RPS-qualified power with PV and then dissipating it through excess transmission losses. Turning off the transmission losses constraint was determined to be the most facile method of avoiding the problem, without losing the potential to gain the broad level insights required.

Considering the many real-world power system issues that are not included in this model, in addition to some penalising aspects of the modelling of solar energy (see Section 4.2.2), the absolute values should not be of primary interest in the results but the patterns that develop across the model runs for different photovoltaic deployment scenarios.[3]

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[3] It is acknowledged that the technical implications associated with the scale of deployment of photovoltaics as illustrated in some scenarios here would be quite significant - this analysis does not consider these implications in detail. Technical issues such as those highlighted in Section 3.1 would have to be understood to a greater degree before the greater levels of deployment shown here could occur.

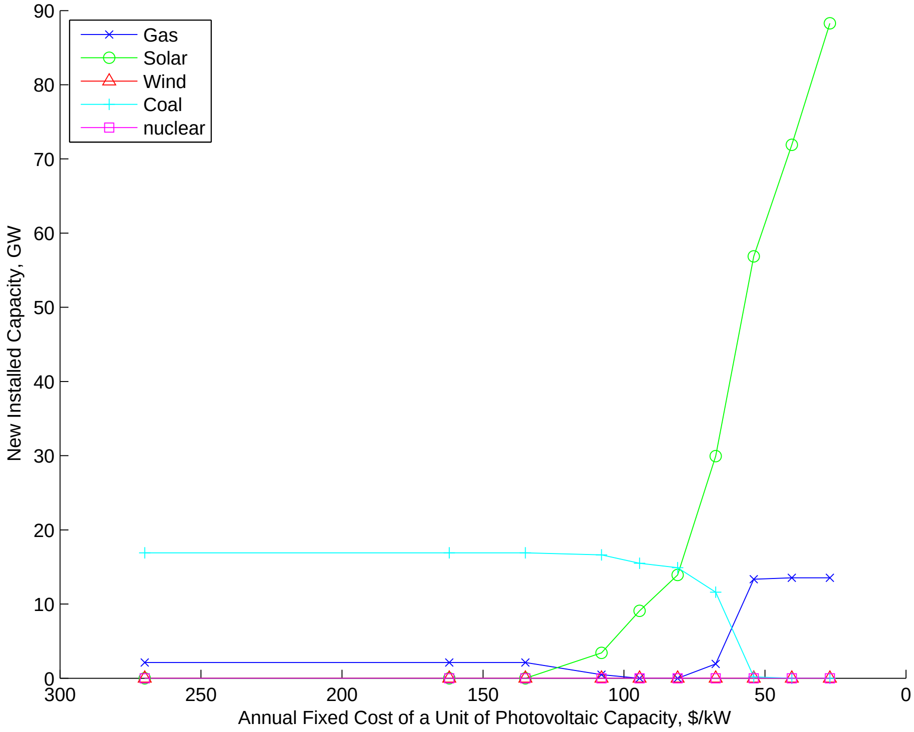

Figure 6-3: New Generation Capacity versus Declining PV Fixed Costs

6.3.1 Investment

Generation Investment

Figure 6-3 and Figure 6-4 show the level of new generation capacity by technology as a function of the annualised fixed cost of a unit of PV capacity and as a function of new PV generation capacity (as costs reduce) respectively.

A noticeable trend in Figures 6-3 and 6-4 is that the first quantities of PV installed displace both coal and gas generation capacity. As PV is increasingly deployed, it is the baseload coal capacity that is displaced while gas capacity increases. Why this potentially interesting finding occurs is discussed in detail in Section 6.5 below. It should be noted that this baseload displacement occurs at relatively high quantities of installed PV capacity. To place this new capacity investment in the context of the system as a whole, Figure 6-5 includes the pre-existing capacity of the system in the y-axis totals.

As PV capacity increases, it can also be noticed that the model begins to construct gas capacity, presumably as this is the most economic way of having the capacity to provide electricity in those hours that the sun does not shine.

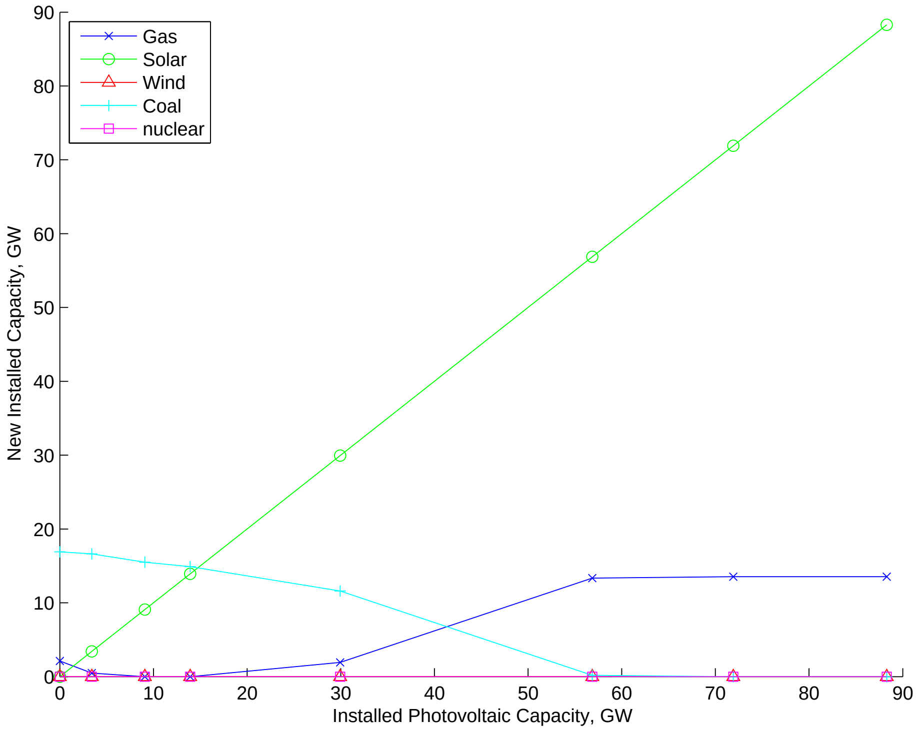

Figure 6-4: New Generation Capacity versus PV Capacity (cost reduction case)

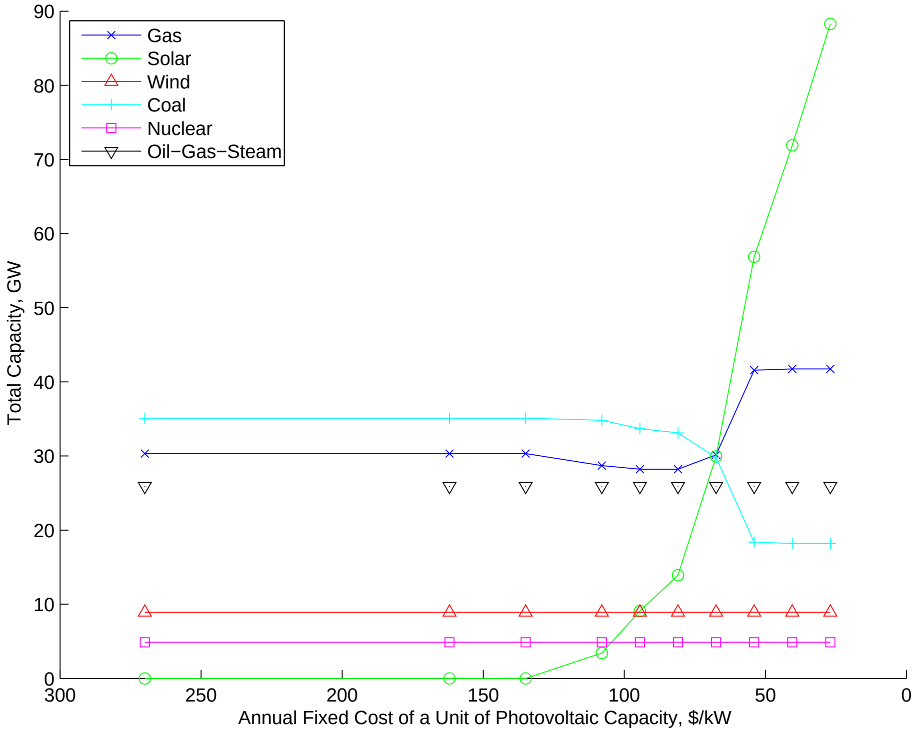

Figure 6-5: Total Generation Capacity versus Declining PV Fixed Costs

Noting that the model has no retirements included, displaced conventional capacity above refers to capacity that would have been constructed if PV did not enter the system. Coal is the technology that is primarily constructed within the model base case, and it is a possibility that this is the primary reason why it is displaced. To address this point, Figure 6-6 compares the optimum solution for a range of PV costs for the design of a completely new system. As is apparent, baseload capacity is also displaced in this scenario.

Figure 6-7 presents the same results as Figure 6-4 but for a different PV deployment scenario. In this case, PV capacity is forced onto the system by an RPS scheme. As discussed previously, this can also represent a premium feed-in-tariff scheme of corresponding design. As can be seen from the figure, the RPS produces a similar overall result in terms of technology mix.

An RPS scheme however does produce a different distribution of PV capacity by location. This can be seen by comparing Figures 6-8 (cost reduction case) and 6-9 (RPS case). As indicated by both earlier results and analytical development, the RPS encourages solar development in the western nodes of 61 and 62, where the highest quality solar insolation resources exist, while in the case of PV cost reduction, the capacity is installed on a more distributed basis and closer to electricity demand.

Finally for this section, a carbon price of $30/tonne is applied to the two PV deployment paths considered here, the cost reduction path and the RPS path. The results are displayed in Figure 6-10 and Figure 6-11. Broadly similar results can be seen for the two deployment scenarios. Compared to the cases with no carbon price, a noticeable outcome in the base case is that the model constructs no new coal or gas generation capacity but zero carbon emissions nuclear capacity. Thus again, the trend remains that 'baseload technologies' are displaced by PV capacity.

Transmission Investment

Figure 6-12 shows the cumulative levels of transmission investment for the cost reduction and RPS cases. Dollars are used as the metric for comparing total investments across lines of different lengths and capacities.

As PV costs reduce, and generating capacity is first invested in, transmission investment increases (by circa 30%). However as PV costs continue to decrease, this investment levels out as PV capacity is invested in on a more distributed basis. This is in contrast to the

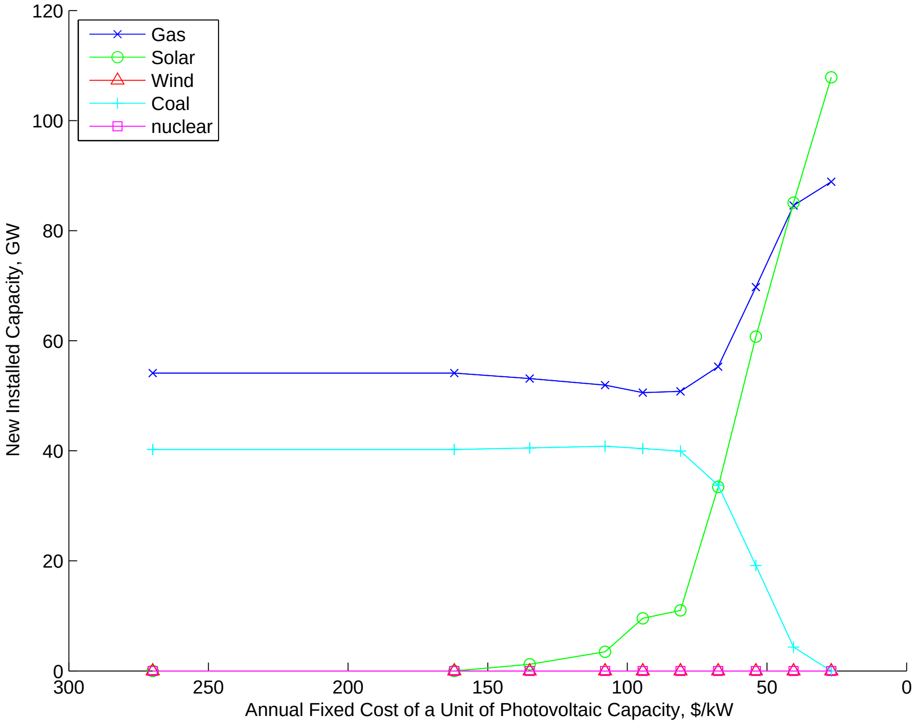

Figure 6-6: New Generation Capacity versus PV Capacity (for ERCOT system built anew)

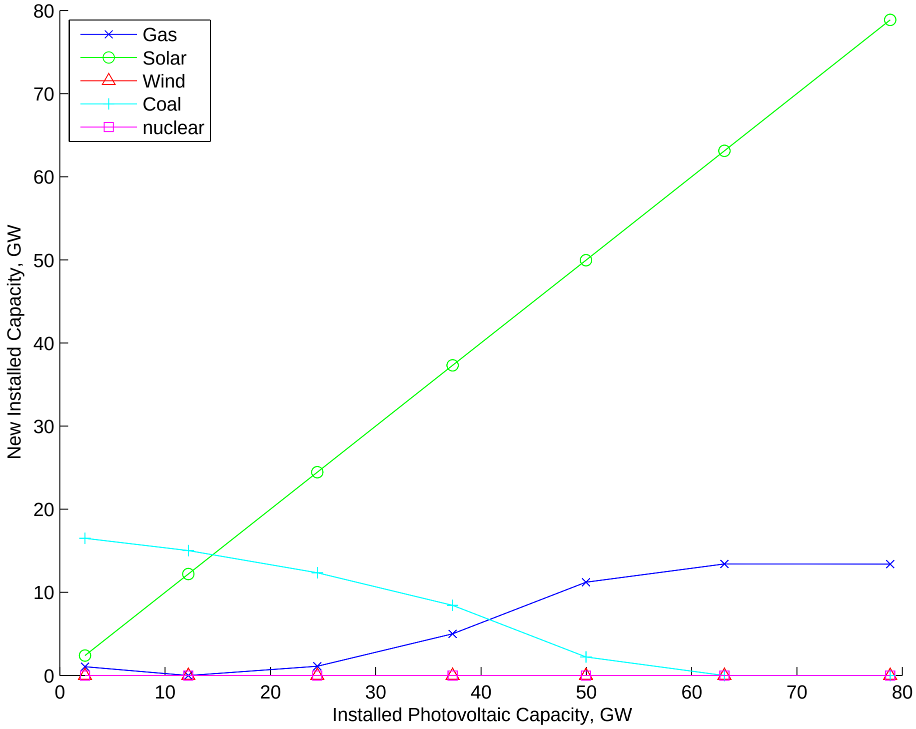

Figure 6-7: New Generation Capacity versus PV Capacity (RPS case)

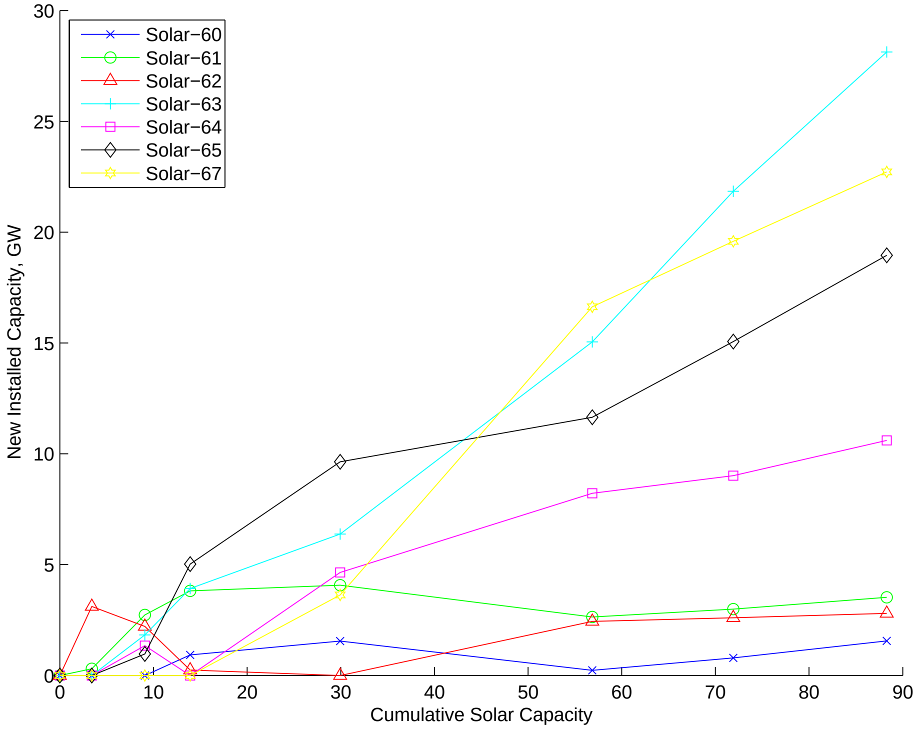

Figure 6-8: PV Capacity by Node versus Aggregate PV Capacity (cost reduction case)

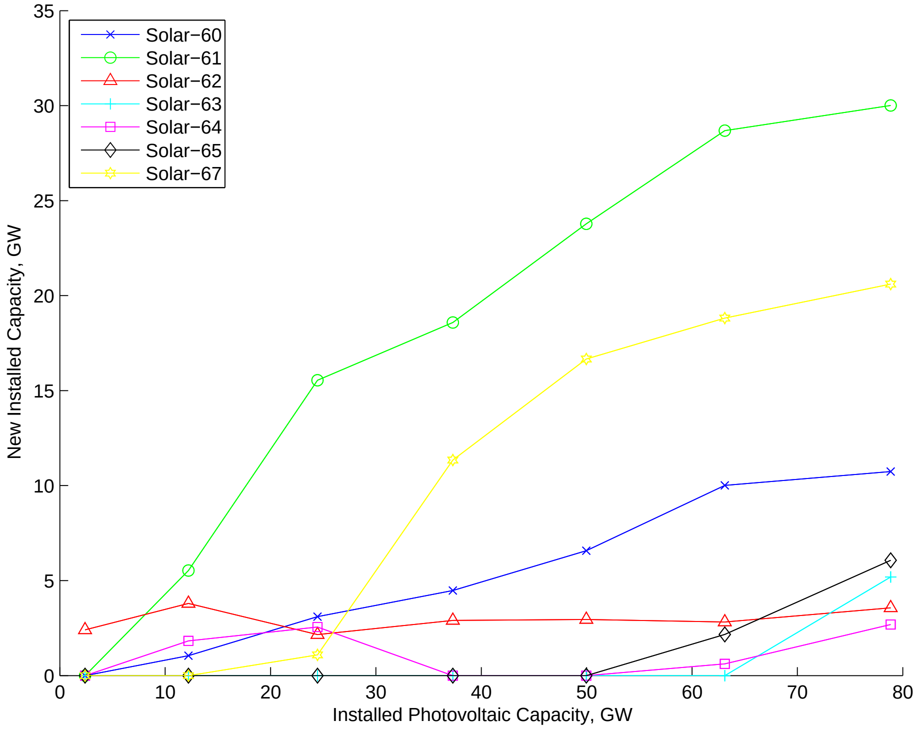

Figure 6-9: PV Capacity by Node versus Aggregate PV Capacity (RPS case)

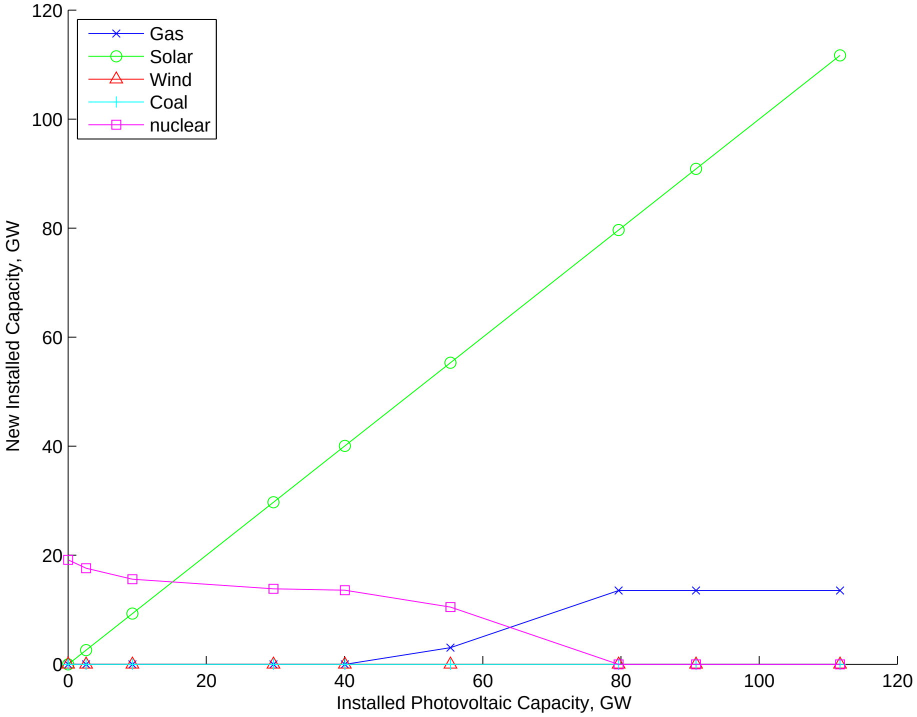

Figure 6-10: New Generation Capacity versus PV Capacity under a Carbon Price of \$30/tonne (cost reduction case)

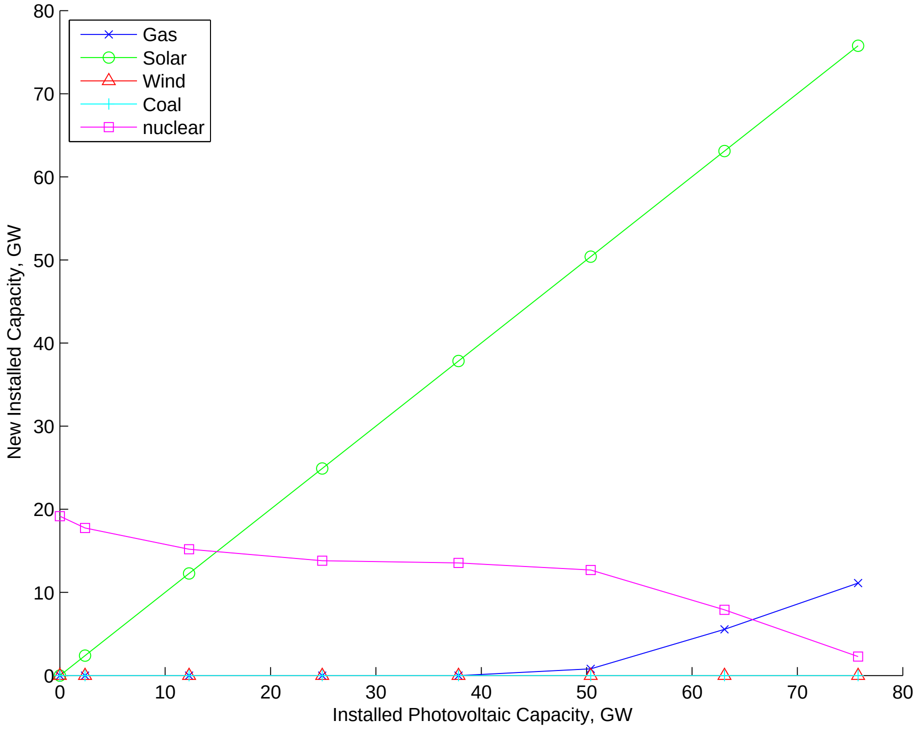

Figure 6-11: New Generation Capacity versus PV Capacity under a Carbon Price of \$30/tonne (RPS case)

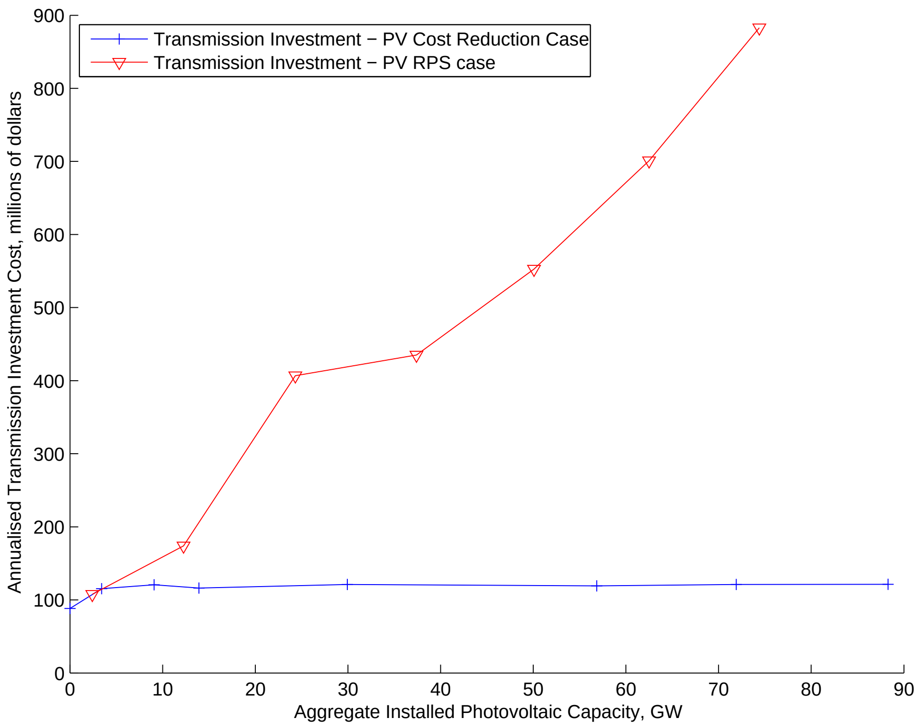

Figure 6-12: Transmission Investment versus PV Capacity for Both Deployment Paths

RPS case where transmission investment continues to increase as PV capacity is increased - as again the cost of PV capacity is expensive and thus the focus is on investing at the best resources.

6.3.2 Dispatch and Scheduling

Figure 6-13 shows the cumulative generation of existing and new generation technology over the 8760 hours of the year as a function of installed PV capacity for the cost reduction scenarios while Figure 6-14 shows the same information for the RPS case. These figures show a similar pattern to that observed in the figures discussing capacity with coal generation decreasing and gas increasing. There is an exception to this however at higher quantities of PV capacity where gas generation starts to decline (while the capacity continues to increase). This is an effect of, as we will be shown below, the gas generation becoming increasingly 'peaky' in profile as the PV penetration increases. It can be noted that wind generation and nuclear generation hold relatively constant.

To further present the change in the system's generation profile, the Load Duration curve for a number of scenarios is included in Figure 6-15. Note that with increasing quantities of renewables on the system, a) the area under the net load curve for conventional generators to provide electricity to is reduced and b) the slopes at either end are steeper. The curve also highlights the existing effect of wind generation on the conventional load duration curve prior to any solar installation in the ERCOT system.

To provide an illustration of the photovoltaics impact on day-to-day dispatch within the system, Figures 6-16 and 6-17 compare 360 summertime hours with and without photovoltaics on the system. Points to note when comparing the graphs include the reduction in the level of generation at which baseload is operating, and a more ‘peaky’ pattern of gas production due to some, but not all of the peak being served by the PV generation.

An example of a very high deployment scenario is shown in Figure 6-18. The curtailment that occurs these days is different from that caused by localised transmission constraints but is caused by aggregate PV supply surpassing demand. The lack of realistic technical ramping constraints on the existing baseload generation in the model are apparent in this figure, with the cycling shown here for nuclear plants unlikely to be technically possible, thus leading to a curtailment of PV generation prior to PV generation exceeding demand. This figure thus highlights two future limit to PV’s contribution to power systems, without the support of other technologies such as energy storage possibilities.

Curtailment

Figures 6-19 (cost reduction case) and 6-20 (RPS case) show the extent of curtailment as a percentage of total potential production of generation of that technology at the node in question. Curtailment in this model can be caused by transmission constraints or simply by aggregate supply surpassing demand.

Significant differences can be observed between the curtailment patterns in the RPS case and cost reduction case, with significantly more curtailment occurring in the latter. In the RPS case, curtailed solar generation goes against the model’s goals of fulfilling the RPS. When costs are reduced however, there are no similar incentives and the extent of the curtailment is taken into account in the model’s investment decision in the PV technology.

6.3.3 Carbon Emissions

Figure 6-21 displays how carbon emissions decrease across model runs with increasing quantities of PV generation - with and without a carbon price.

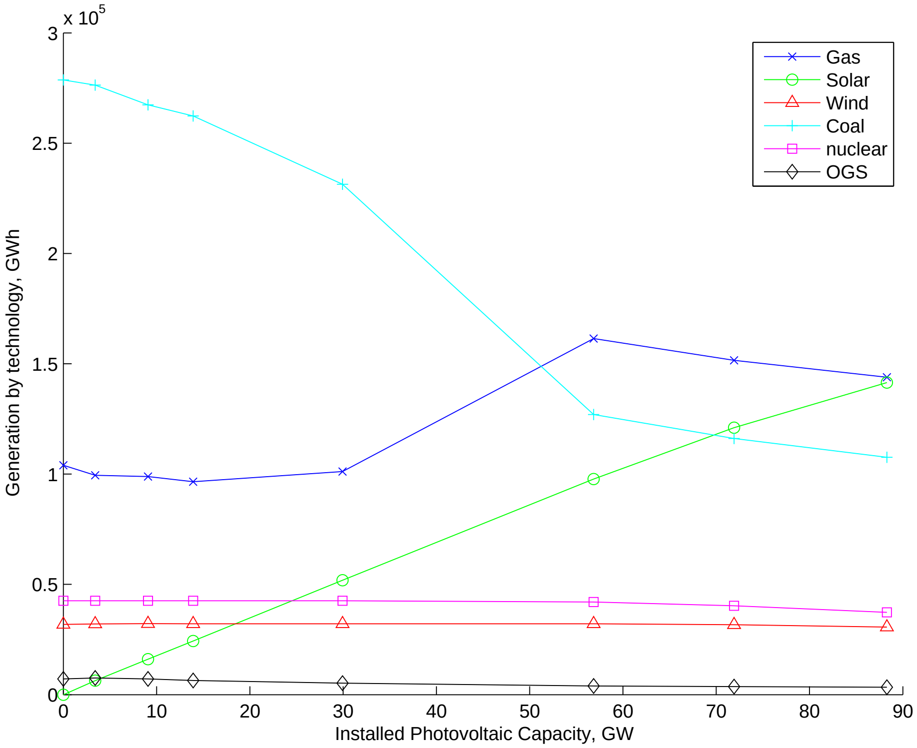

Figure 6-13: Generation by Technology versus PV Capacity (cost reduction case)

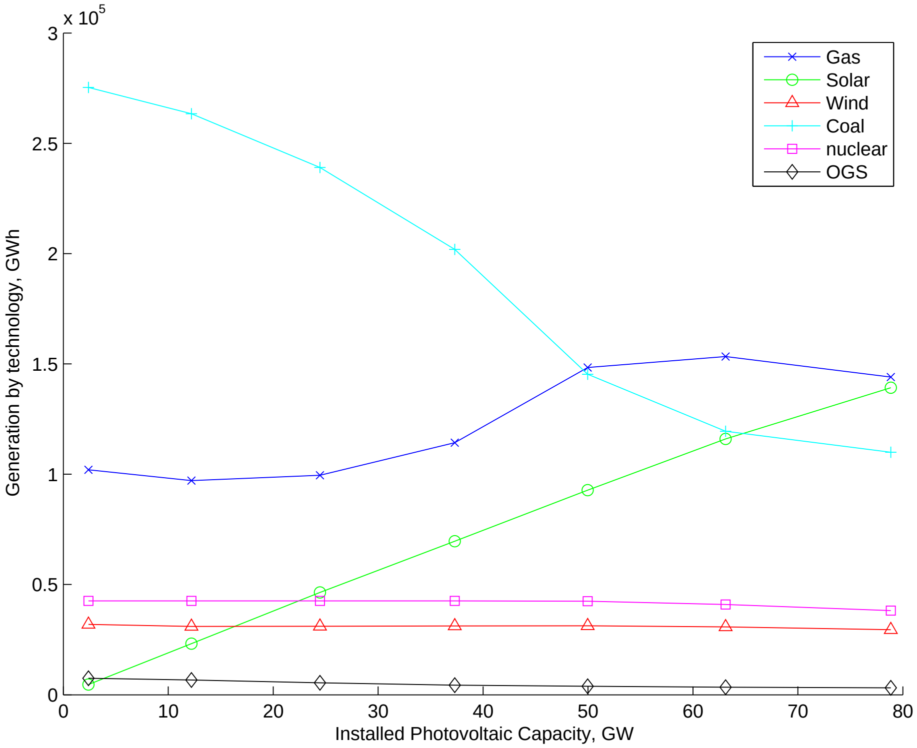

Figure 6-14: Generation by Technology versus PV Capacity (RPS case)

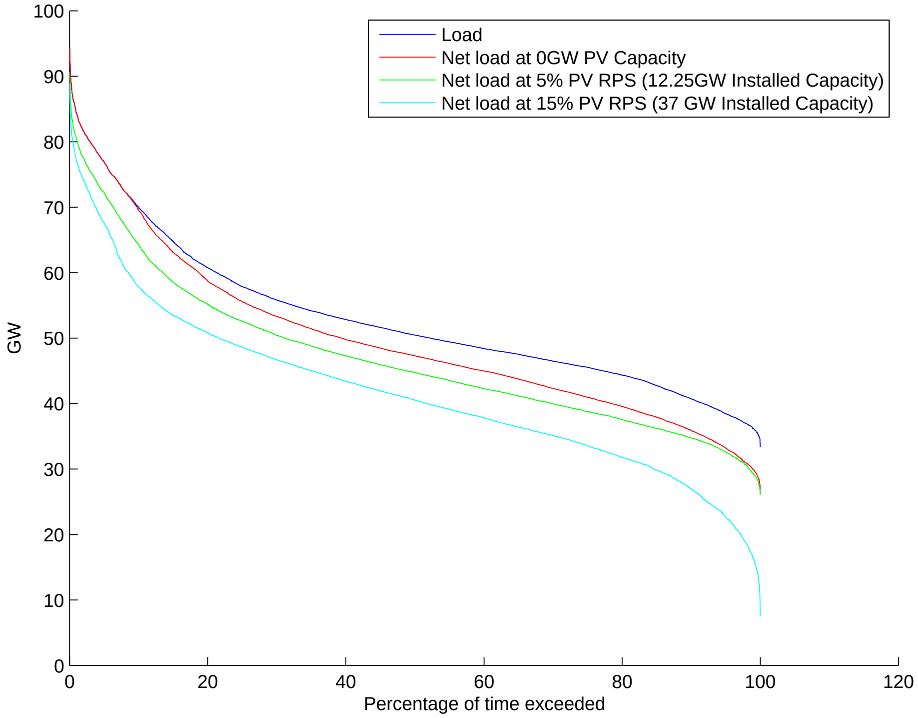

Figure 6-15: Load Duration Curves for different scales of PV Deployment
Note that load / net load data re-sorted for each curve.

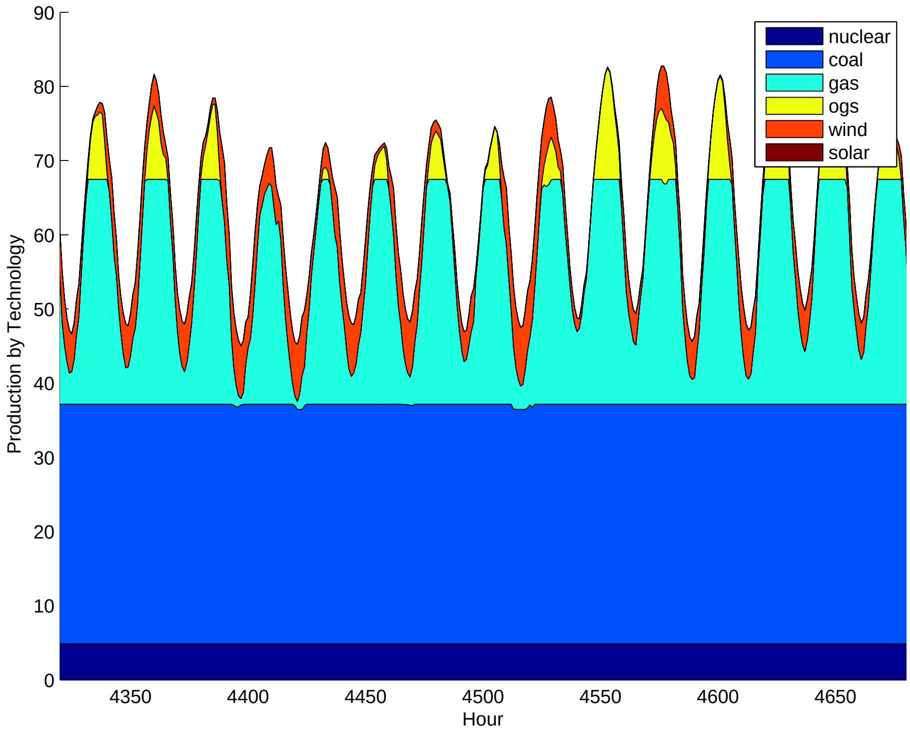

Figure 6-16: Production Profile for 15 Sample Summer Days - Base Case

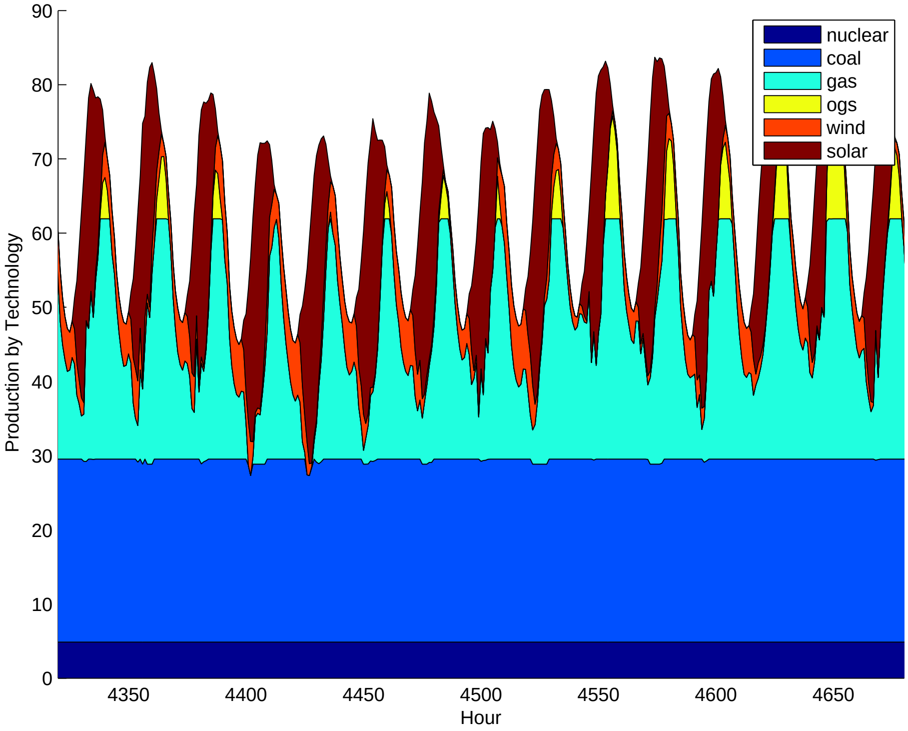

Figure 6-17: Production Profile for 15 Sample Summer Days - 15% PV RPS (37GW nameplate capacity)

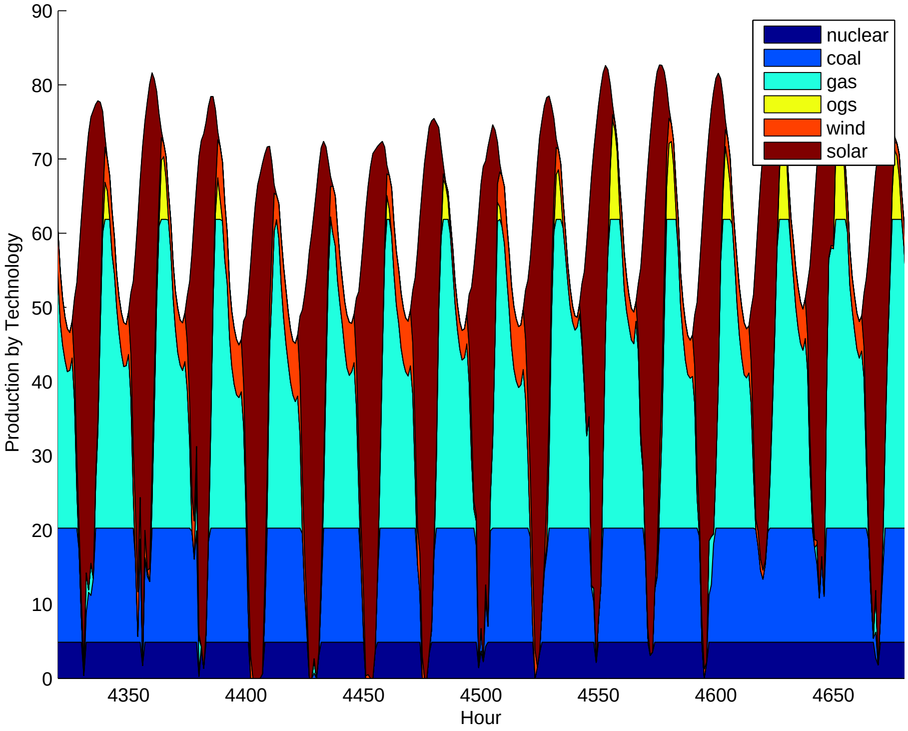

Figure 6-18: Production Profile for 15 Sample Summer Days - 30% PV RPS (79GW nameplate capacity)

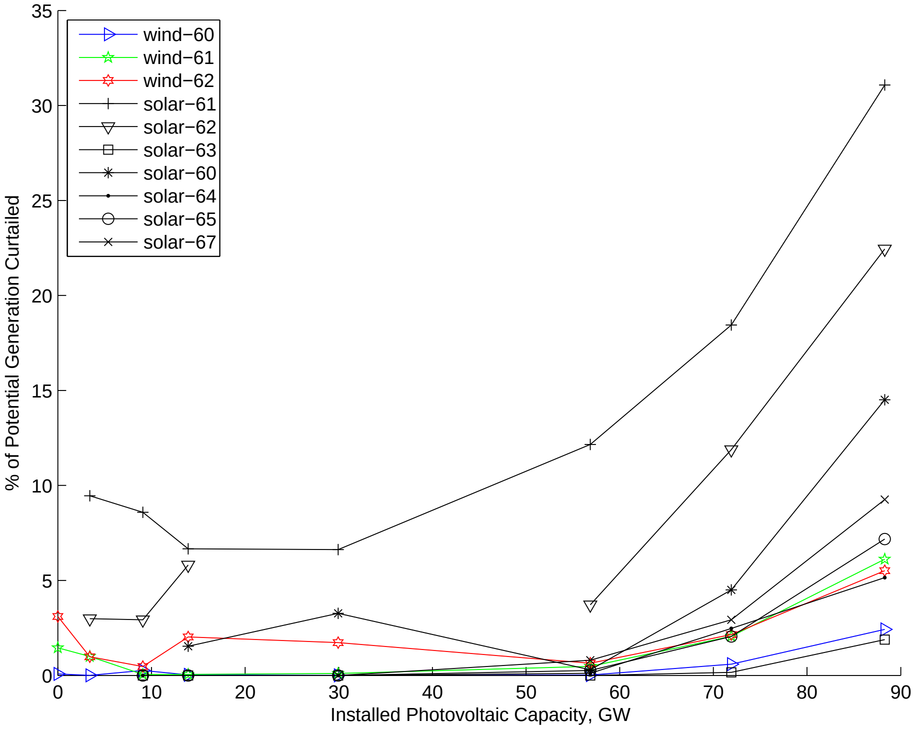

Figure 6-19: Curtailment of Renewable Generation versus PV Capacity (cost reduction case)

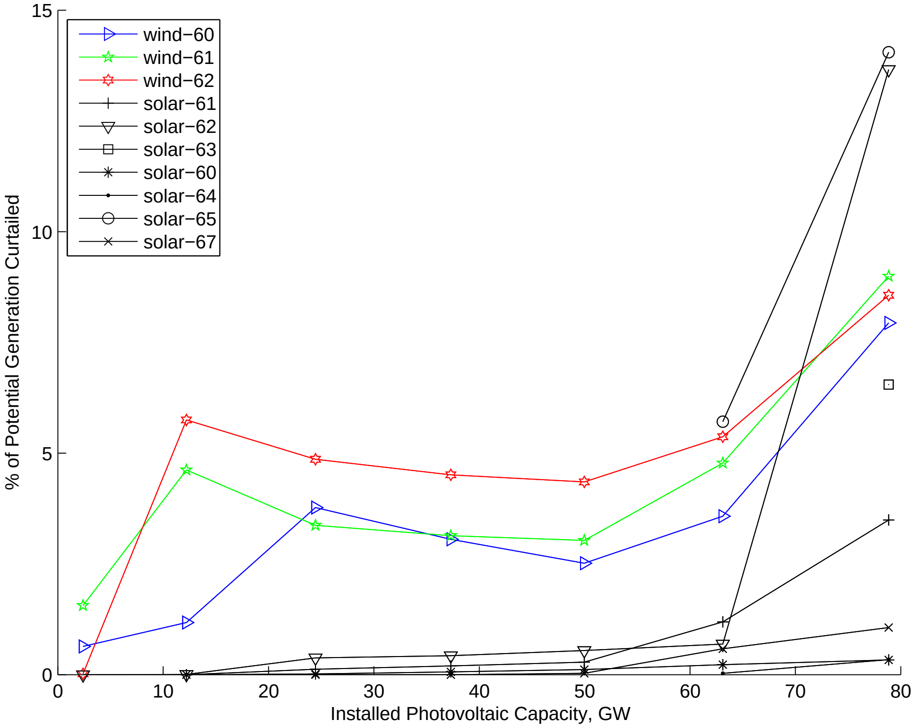

Figure 6-20: Curtailment of Renewable Generation versus PV Capacity (RPS case)

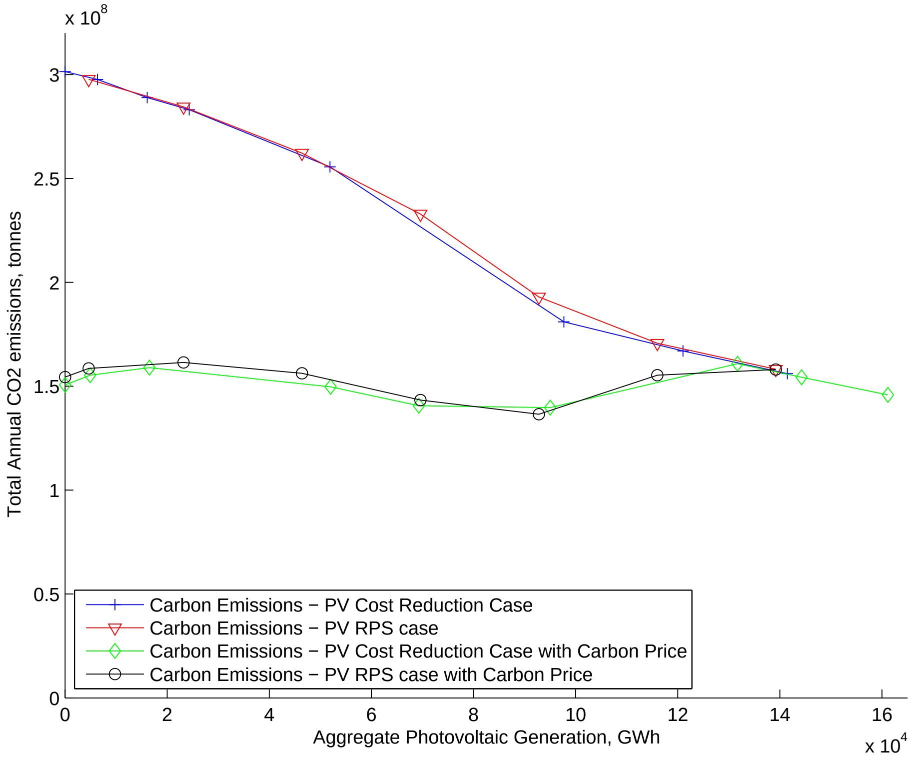

Figure 6-21: Carbon Emissions versus PV Generation (cost reduction and RPS cases)
In the carbon price cases, PV capacity replaces carbon-free nuclear capacity.

Considering the cases without a carbon price, it can be noticed that at the right hand side of the graph, the rate of reduction flattens - at this stage gas is being displaced along with coal, thus leading to a reduction in the emissions savings per unit capacity displaced. Similarly the rate of most rapid decrease is in the center of the graph - where only coal is being displaced.

Considering the cases with a carbon price - it can be seen from both the RPS and cost reduction scenarios that the effect of increasing PV capacity on carbon emissions is ambiguous. This is because in these cases, as we have previously shown, PV is displacing nuclear baseload capacity, constructed in response to the carbon price in the base case.

This example highlights the importance of understanding what technology may get displaced if one of the justifications for the deployment of renewables is greenhouse gas emission reductions. This relates to the issue of marginal carbon intensities as discussed previously and further developed by [79].

6.3.4 Nodal Pricing

To consider the distribution of prices over the course of a year, Figure 6-22 shows a price duration curve for Nodes 61 and 67 and location weighted average for a zero solar penetration case. Note that existing wind capacity in the base case at the western node 61 leads to a zero price at almost 10% of the hours of the year. The curve is largely flat and stepwise, which can be attributed to the high quantity of gas generation capacity in the ERCOT system in addition to the lack of differentiation amongst each technology in the model. Also, as long-term marginal costs are shown, the peak of the graph is truncated for visual purposes. There is no reserve margin requirement in the model thus the marginal cost of meeting a unit extra demand at peak demand time is extremely costly as the system will be at its limits. This reserve margin issue is discussed in Section 6.1.2.

Figure 6-23 shows the same information but for the 15% PV RPS case. It is noticeable from the right hand side of the graph that the average price has decreased significantly, going to zero in a number of hours. Even in the location furthest from the solar resource - node 67, a decrease in prices can be noted. In addition, the percentage of time where the price rises from just above 40$/MWh to 55$/MWh decreases across all 3 cases (from approximately 9% to 5%). Not shown on the graph is the spike in the peak hour with solar on the system when the system is at its limit - the peak price rises an average of 4.65% across the nodes.

6.3.5 Components of Objective Function

Figure 6-24 shows how the components of the objective function change across the suite of PV cost reduction model runs, while Figure 6-25 shows the same information for the RPS runs.

The figures show that a large proportion of conventional system savings due to the onset of PV onto the system is due to the reduced fixed and operating costs of baseload technology. In addition, it is noticeable that the aggregate operating costs of gas generation actually increases as the system adapts to increases in photovoltaic deployment, contrary to what would be the short-term expected impact on cumulative gas operating costs (which would be a decrease).

In addition, transmission costs in the objective function are a small proportion of total

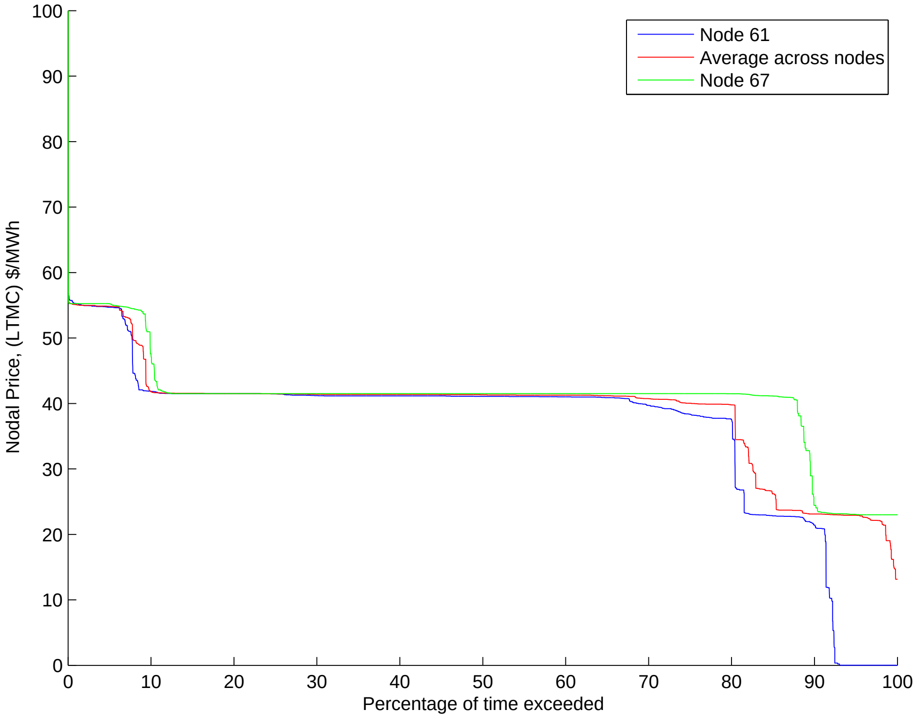

Figure 6-22: Price Duration Curve - Base Case (0 GWPV capacity)

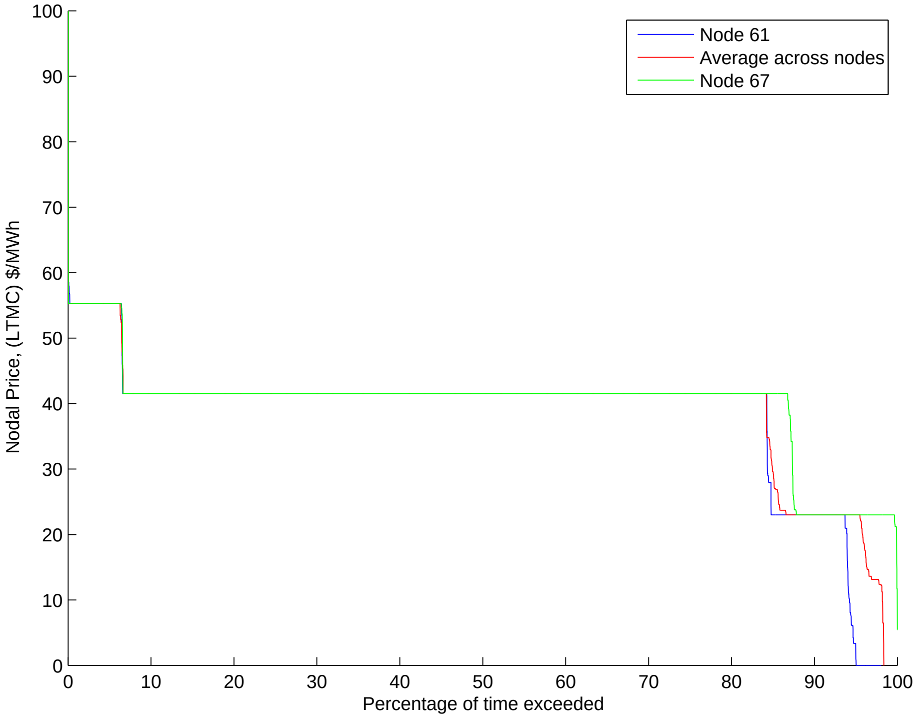

Figure 6-23: Price Duration Curve - 15% PV RPS case (37 GW PV capacity)

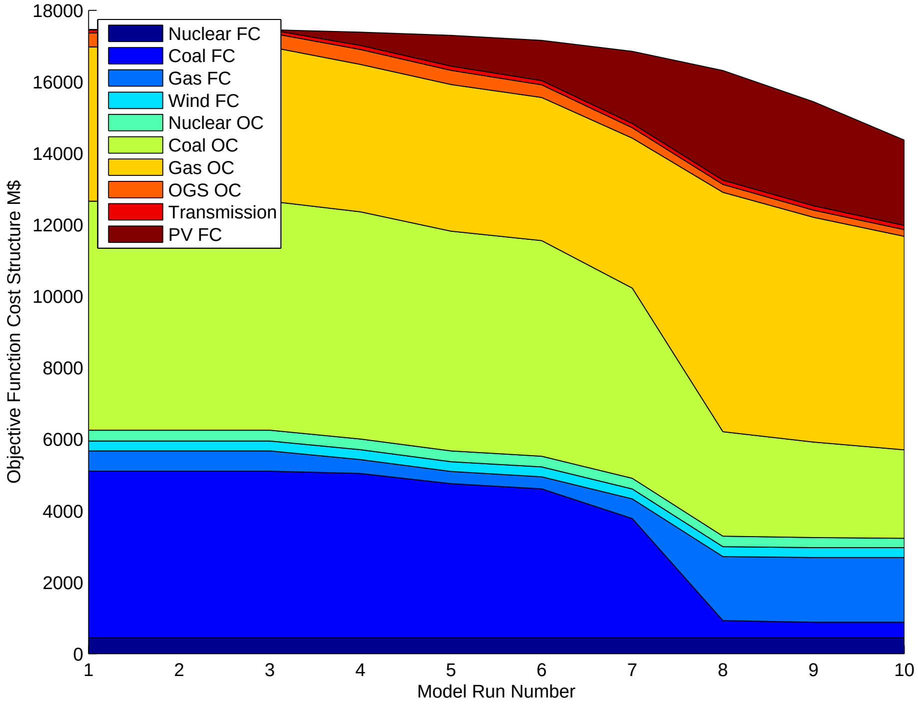

Figure 6-24: Change in Objective Function Components Across Model Runs (PV capital cost reducing from left to right)

system costs, however, as we have seen previously, transmission can have a large influence on the extent and distribution of PV deployment. Also, one difference between the figures is that transmission is a larger component in the RPS case, which aligns with previous discussion.

It should be noted that being a static optimisation model decided for the future in a cost-minimising fashion, that the objective function does not represent the costs of the whole system but the costs to meet demand in some future year by the construction of new generation and transmission capacity and the operation of all capacity. Thus, the investment costs of the existing technologies are not included while in a real system, the costs of the generation and transmission assets that had not lived out their economic lives would be an important component of expenditure.

6.3.6 Discussion

- 4 suites of model runs were undertaken, (i) with PV capital cost gradually ramped down across each static optimisation, (ii) with a PV specific RPS gradually ramped up, ((iii) & (iv)) each of the above with a carbon price of $30/tonne included.

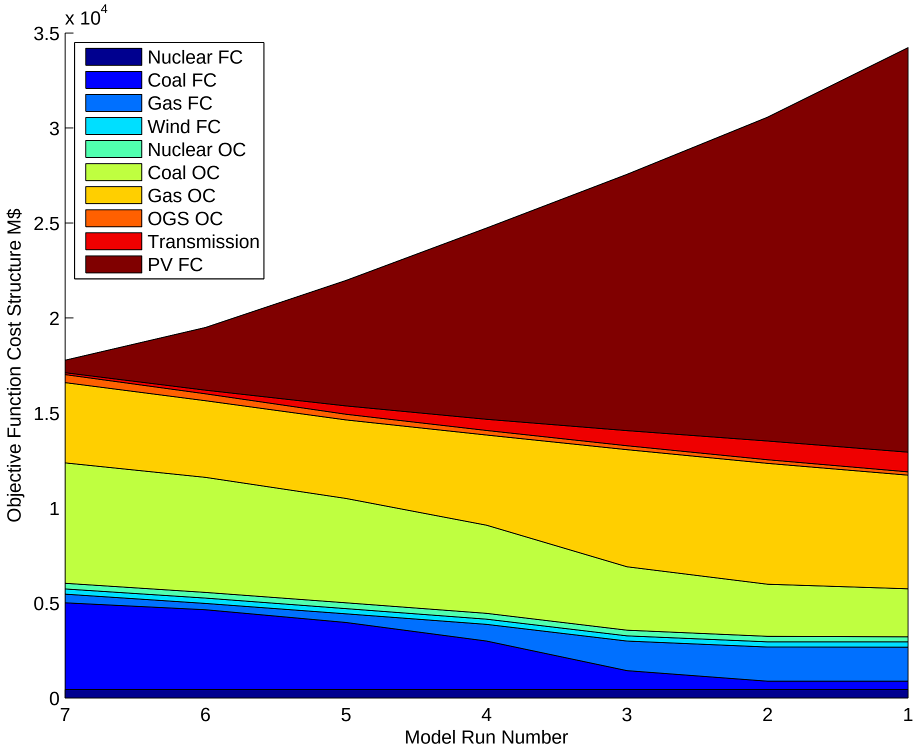

Figure 6-25: Change in Objective Function Components Across Model Runs (RPS increasing from left to right)

- The onset of photovoltaics onto the system over the long term due to reduced costs leads to a reduction in baseload capacity investment in the model. The main savings to accrue from the onset of photovoltaics was the reduction in baseload fixed and operating costs. More discussion on why baseload generation is displaced is presented in Section 6.5 below.

- Additional gas capacity was constructed as the quantities of photovoltaics entering the system increased to very high levels, with an associated increase in operating costs with the use of this gas capacity. The opposite occurred in cases with lower levels of PV deployment, e.g. at 10GW PV capacity.

- Different paths between PV entering the system by cost reduction and by RPS were noted. In the case where PV enters due to reduced costs, investment on a more distributed basis occurs, with limited additional transmission investment and more tolerance for curtailment of solar production. When PV enters the system due to an RPS, more transmission investment is required in the system-optimal case as investment is concentrated in the areas of best resources. Curtailment is also reduced under this scenario.

- The technology that the PV generator displaces determines the impact of the generator on emissions. With a carbon price on the system, nuclear (without some its associated real-world constraints) is installed on the system. The arrival of PV capacity on such a system again leads to a displacement of new baseload capacity, in this instance nuclear. PV deployment in this case does not lead to any additional decreases in carbon emissions beyond that achieved by the carbon price.
- The production of conventional generation, particularly intermediate gas plants and peakers, was noted to become 'spikier' as photovoltaic deployment increased.
- A reduction in nodal prices, with differences spatially across the system was apparent.
- The key differentiating factor for PV relative to wind within this modelling framework is the production profile of the photovoltaic technology. Inspecting the production profile outputs that were developed highlighted the limits that exist to photovoltaic deployment without the aid of complementary technologies. 30% of electricity from photovoltaics was shown to be extremely challenging.
- The results highlight how different the technology mix of the future could be, depending on what path is followed (if any in particular) in terms of carbon price and renewable energy supports.

6.4 CSP Deployment Results

As discussed previously, concentrating solar power (CSP) is an alternate means of harnessing the sun's energy for electricity generation, with a different set of characteristics to photovoltaic generation. This section thus considers similar questions to that of the previous section, highlighting different outcomes resulting from CSP deployment.

Concentrating solar thermal power technology is modelled as per description in Sections 4.2.2 and 5.5.4. The plants are assumed to have a solar multiple of two, are designed for a reference direct normal radiation value of 900 W/m^2, and are assumed to include 6 hours equivalent storage. Due to the large land area and strong insolation profile required for economically-viable solar collectors, CSP plants in this model are restricted to the western nodes of 60, 61, and 62.

The non-linear relationship between incoming solar radiation and CSP production, in addition to the constraint of CSP to certain areas are the primary underlying factors differentiating the results below from the photovoltaics case.

To avoid clutter, the RPS case is not shown as the results do not differ significantly from the cost reduction case. This is largely due to the lack of a distributed option in addition to the characteristics of Direct Normal Insolation - DNI variation is more pronounced and thus CSP is generally required to be constructed in the best resource areas.

6.4.1 Investment

Generation Investment

Figure 6-26 shows the deployment of CSP capacity as the cost of the technology decreases across model runs, while Figure 6-27 shows the same information with cumulative installed CSP capacity now on the x-axis. Broadly similar trends can be seen as per the case of PV, with coal capacity being displaced in the model outputs where large quantities of CSP enter the system. As regards gas generation capacity, similarly to PV, the first quantities of CSP which enter the system displace gas capacity but unlike the case of PV, higher penetrations of CSP do not necessitate an increase in gas capacity investment. This is likely due to the storage capabilities of the CSP as modelled here.

Figure 6-28 shows the new capacity investment on the system when a carbon price of \$30/tonne is in place. As previously, nuclear capacity is constructed in the base case. This is then displaced as CSP enters the system.

Figure 6-29 shows the distribution of where the CSP is deployed by the model under a cost reduction scenario. As apparent from the figure, the model constructs the capacity in the area of the greatest direct normal insolation resource, node 61.

Transmission Investment

Figure 6-30 shows how transmission capacity increases as the quantities of CSP capacity on the system increase. Unlike the PV case, the model continues to build transmission as the capital cost of CSP technology reduces. This can be explained by the lack of an option

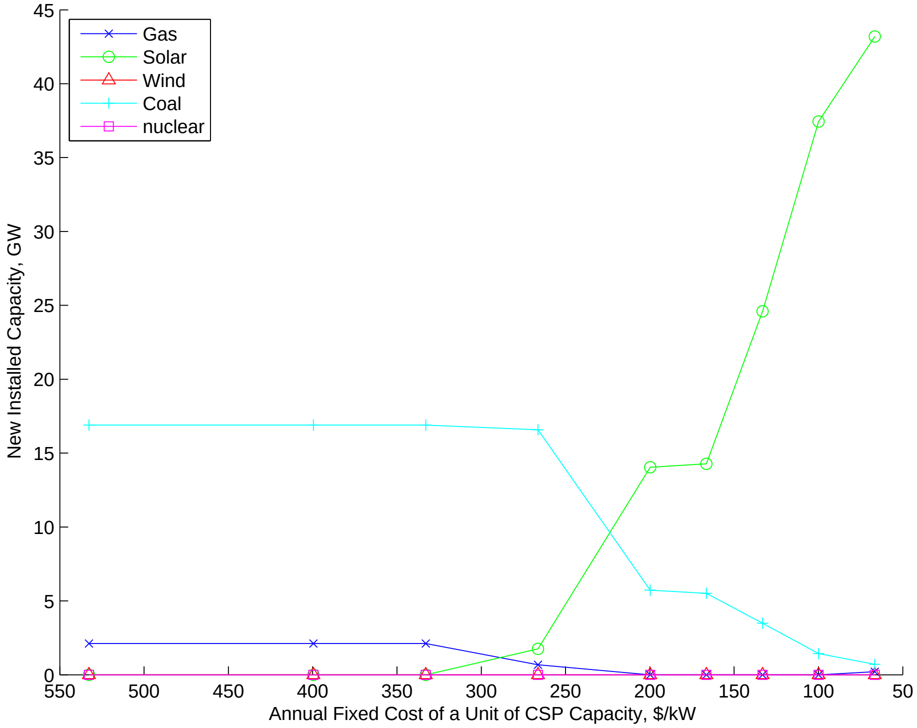

Figure 6-26: New Generation Capacity versus Declining CSP Fixed Costs

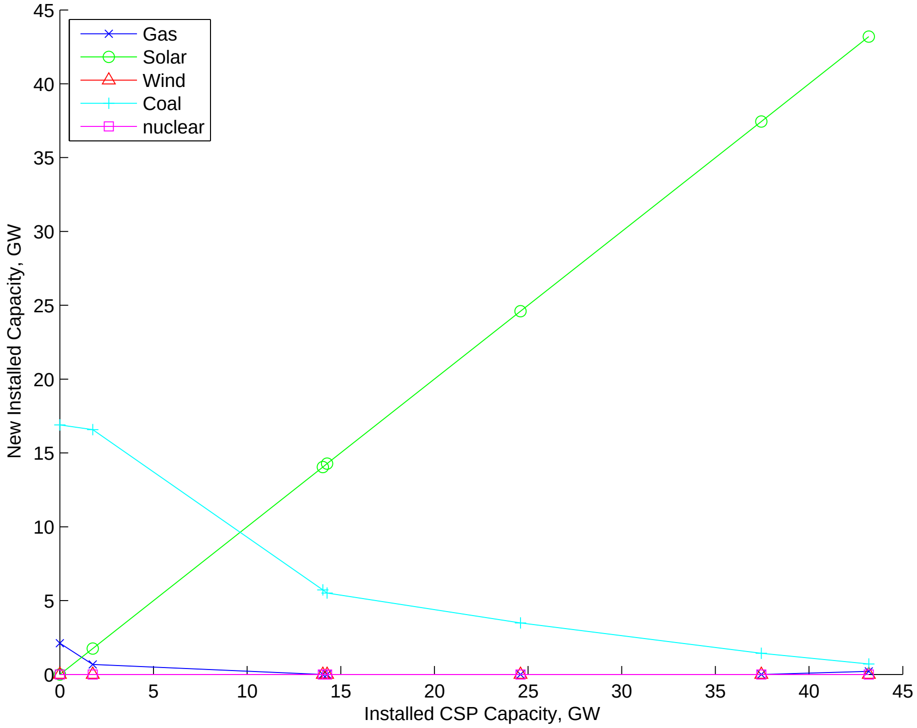

Figure 6-27: New Generation Capacity versus CSP Capacity

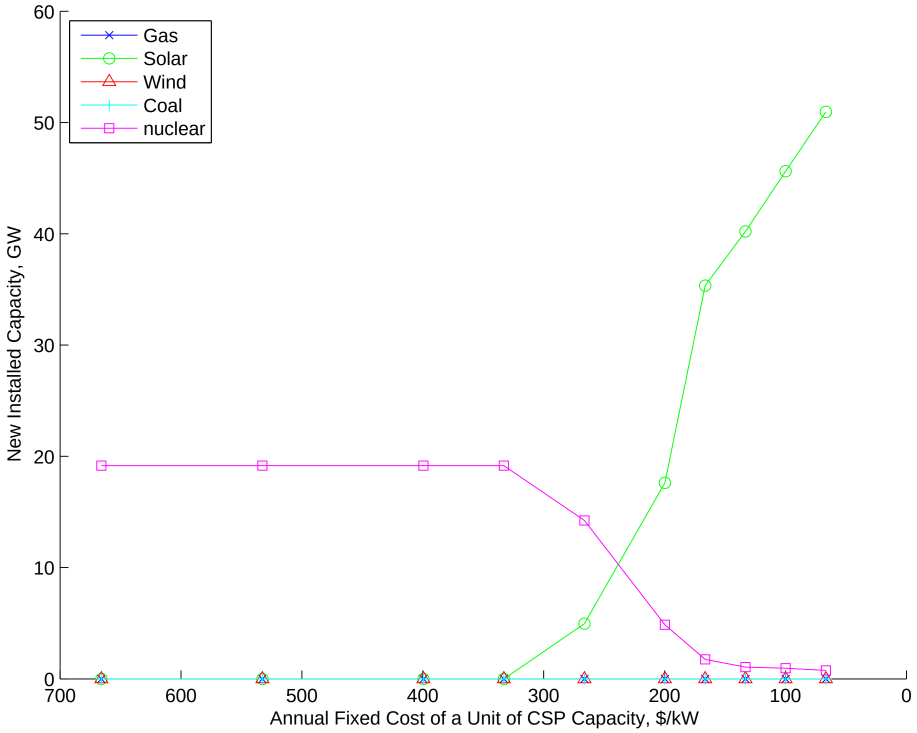

Figure 6-28: New Generation Capacity versus CSP Capacity under a Carbon Price of $30/tonne

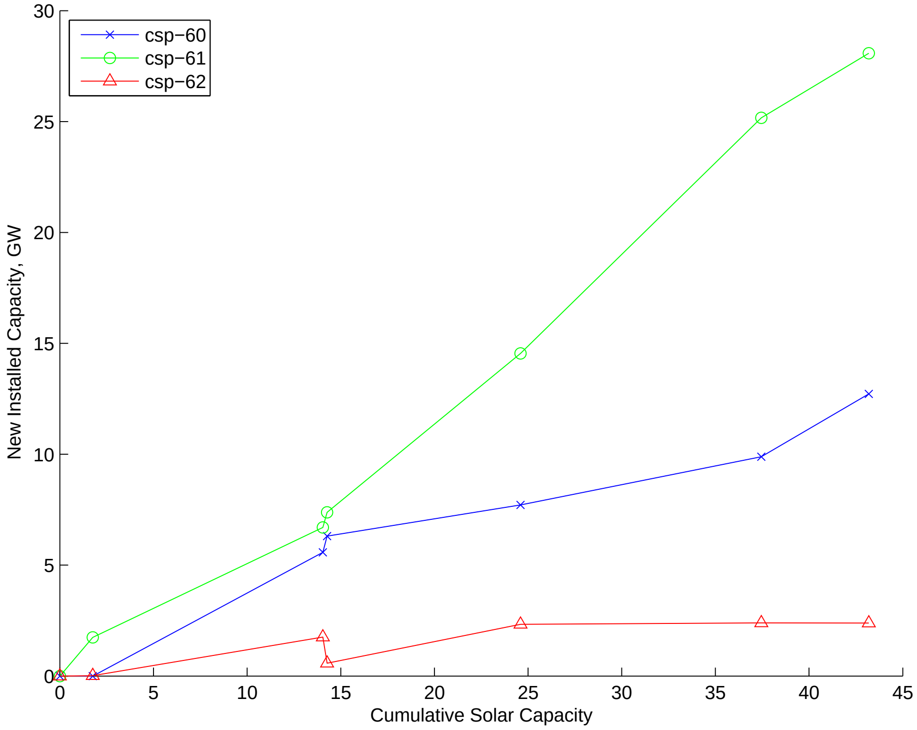

Figure 6-29: CSP Capacity by Node versus Aggregate CSP Capacity

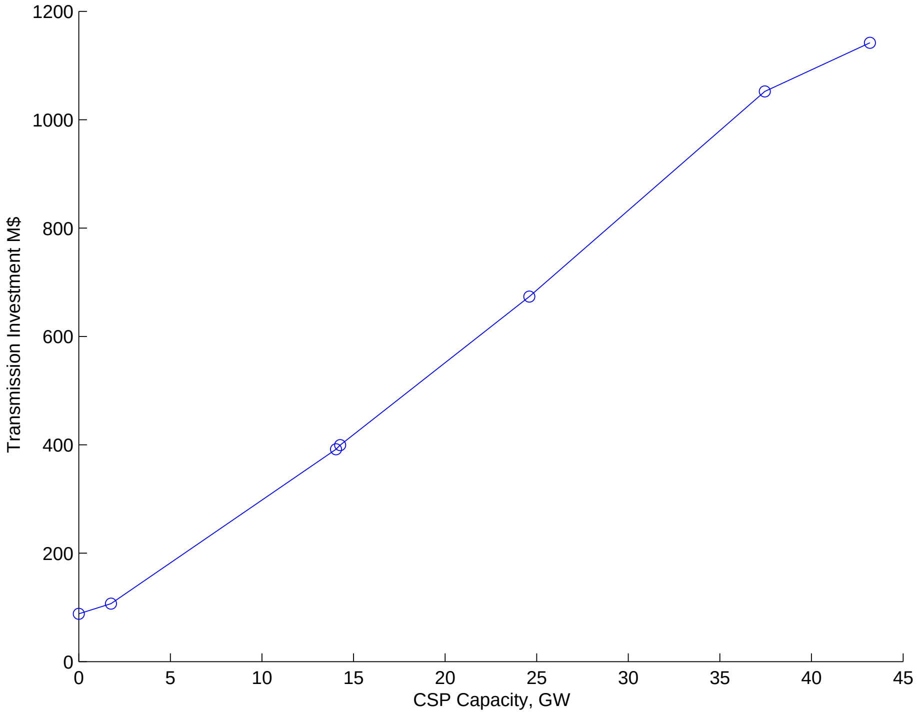

Figure 6-30: Transmission Investment versus CSP Capacity

to install CSP at poorer quality resource locations, but also it can be explained by CSP's higher capacity factor relative to PV facilities, allowing the installation of transmission to a CSP plant to be a more attractive option.

Not shown for the PV cases, Figure 6-31 shows the transmission capacity expansion by line. The figure highlights the continuous nature of transmission investments in this version of the model but also highlights in a simple way how deep transmission reinforcements may be required when remotely located generation is connected to an existing system - the example here is the expansion of the corridor between the eastern nodes of 63 and 64.

6.4.2 Dispatch and Scheduling

Considering generation, CSP shows some slightly different behaviour to that of PV with increasing quantities initially leading to increased utilisation of existing gas plants (greater generation with no new capacity investment) followed by a decrease in gas-fired electricity production as the quantities of CSP entering the system continue to increase (Figures 6-32 and 6-33). In addition, a large decrease is noted in generation from coal.

Figure 6-34 displays the cumulative generation across runs with a decreasing cost of

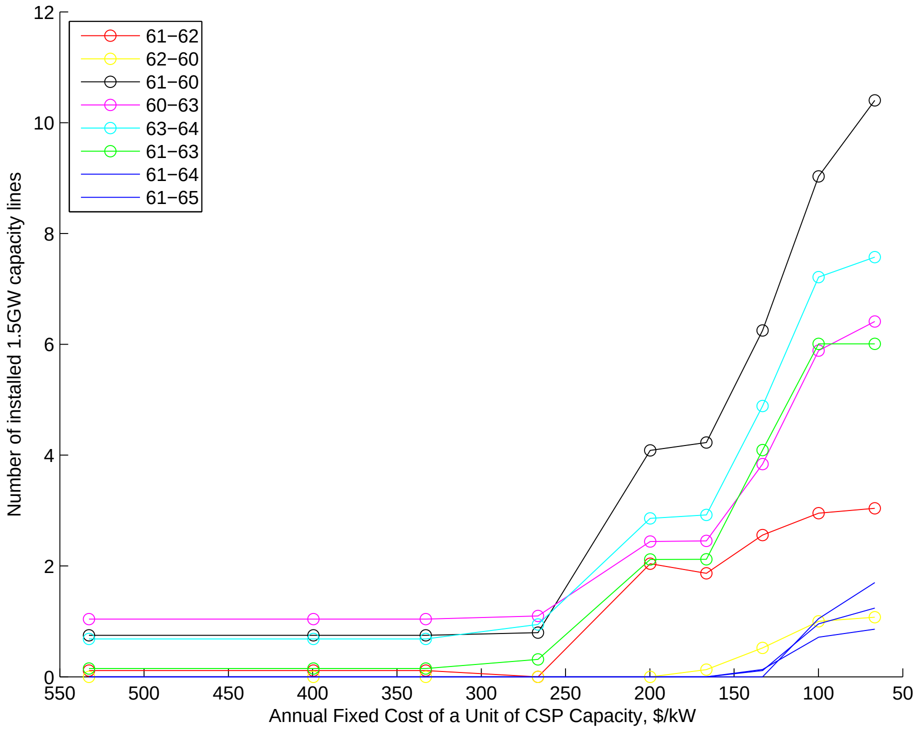

Figure 6-31: New Transmission Capacity by Corridor versus Declining CSP Fixed Costs

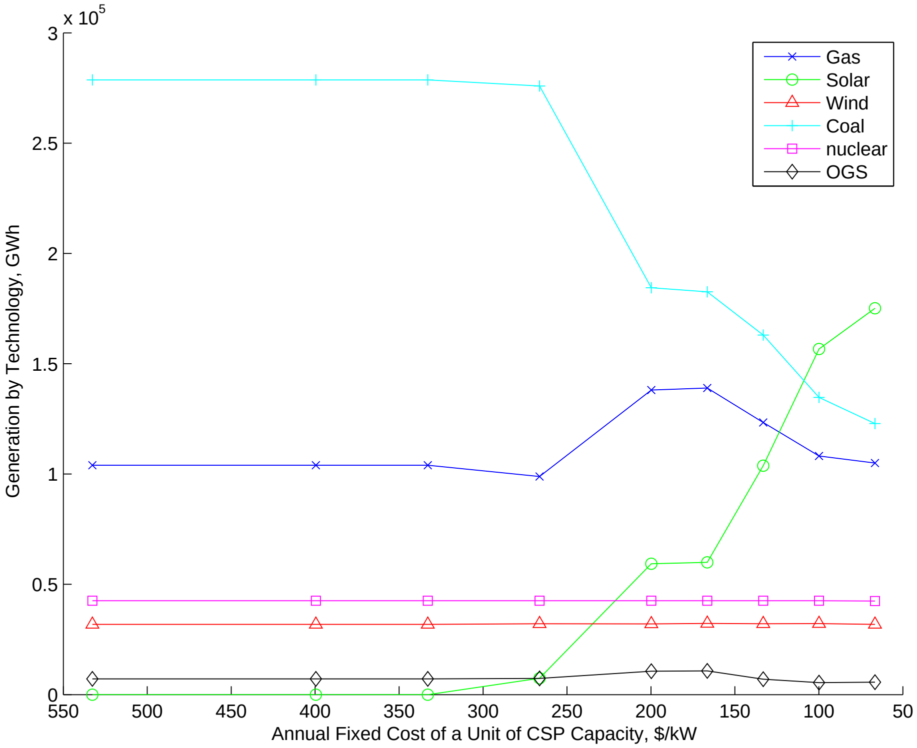

Figure 6-32: Generation by Technology versus Declining CSP Fixed Costs

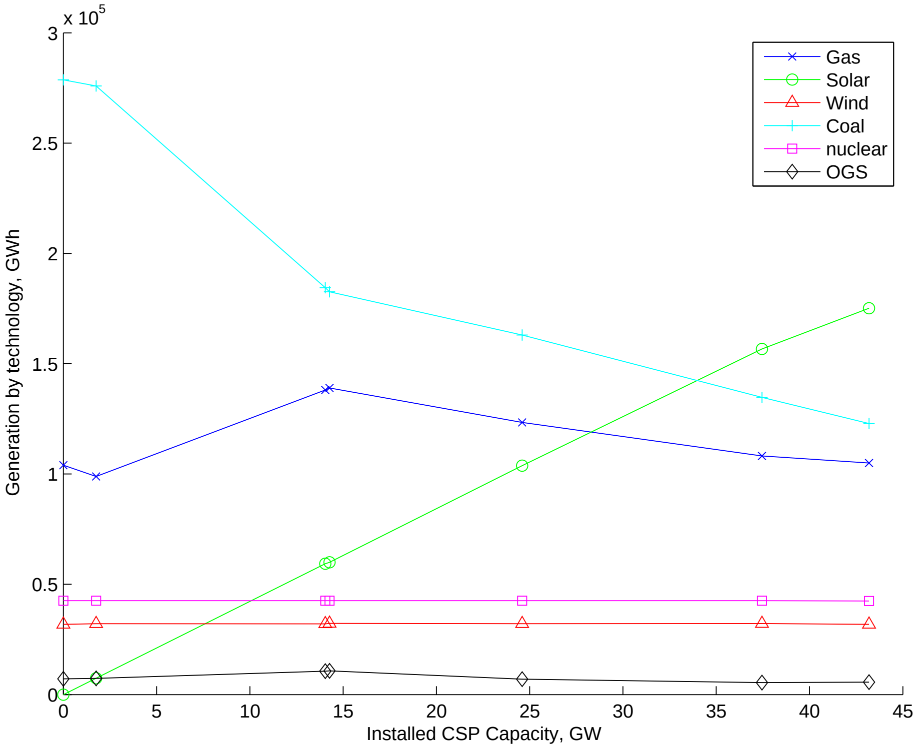

Figure 6-33: Generation by Technology versus CSP Capacity

CSP in addition to a \$30/tonne carbon price. Initially there is an increase in gas generation with increased CSP generation under this scenario. With increasing penetrations of CSP however, the gas generation begins to decrease across model runs.

Figure 6-35 provides a similar result to photovoltaics in terms of the new net load-duration curve. However, the endpoints are not quite as steep and CSP's increased capacity factor and associated storage capability ensures that there is a more consistent shift from the conventional load-duration curve. A particular point of note for this particular system for this particular dataset is the relatively strong contribution of CSP to meeting peak demand with 24.5GW of capacity reducing the peak demand facing conventional generation by 15GW.

Figure 6-36 highlights one of the major differences of CSP generation as included in this model. The 6 hours of storage included in the model allows the CSP facilities to provide power during the whole peak period as opposed to solely the first portion of the period, reducing the requirement for gas generation in the system. It can be noted that even with storage, there are still days when CSP will output significantly less electricity than nameplate capacity due to the weather.

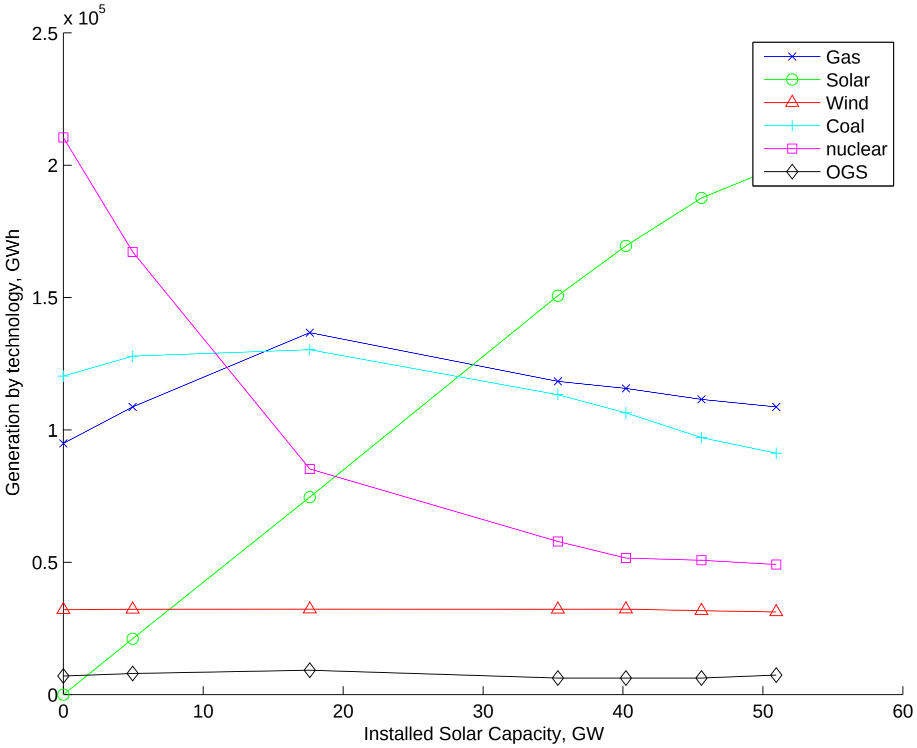

Figure 6-34: Generation by Technology versus CSP Capacity under a Carbon Price of \$30/tonne

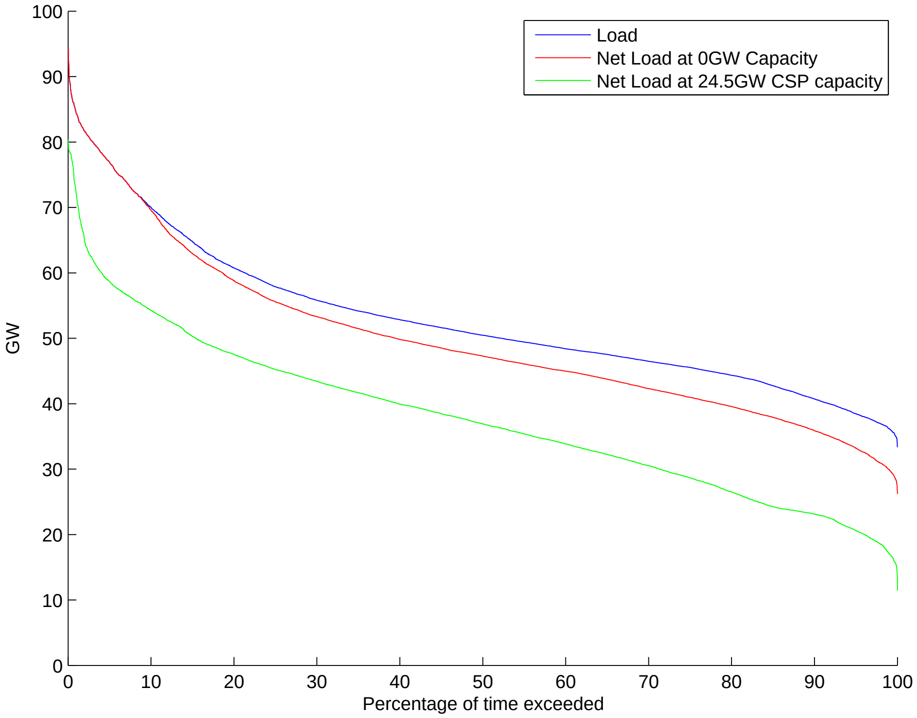

Figure 6-35: Load Duration Curve (24.5GW CSP Capacity)
Note that load / net load data re-sorted for each curve.

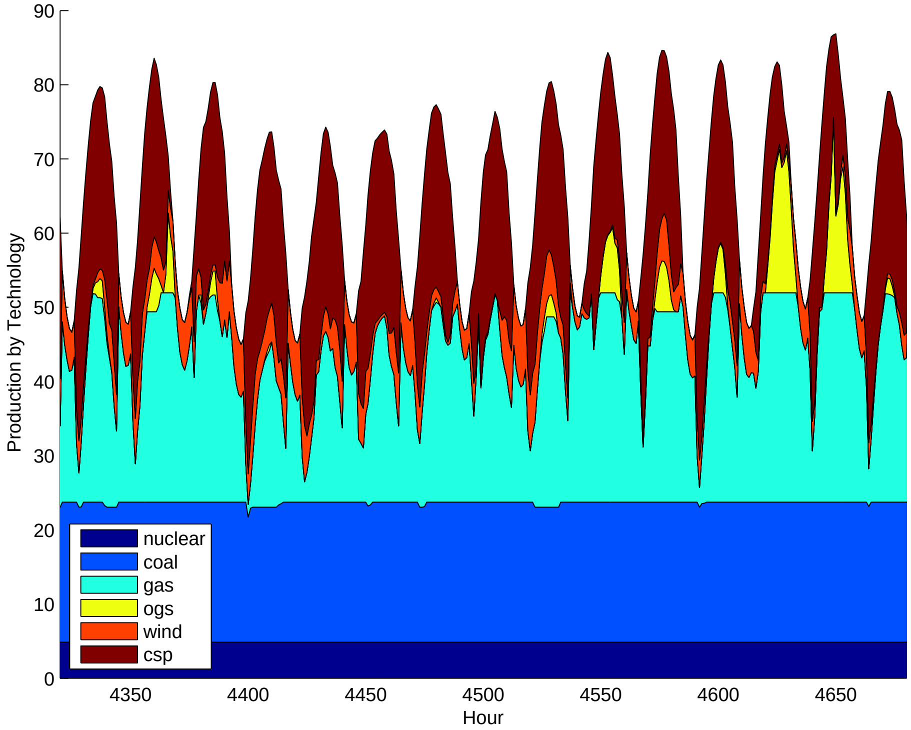

Figure 6-36: Production Profile for 15 Sample Summer Days (25GW CSP capacity)

Earlier in the document (Section 6.3.2 and Figure 6-18), the limitations to photovoltaics without storage providing 30% of the electrical energy demand were apparent. Figure 6-37 shows the profile for 15 summer days in a case where 37% of annual system demand is provided by concentrating solar power. Viewing the profile it is apparent that providing this scale of energy on the electricity system with CSP will cause less disruption to the operation of other technologies on the system. This is additional to the CSP advantage of fitting in the framework of centralised controllable and dispatchable power plants.

6.4.3 Carbon Emissions

Figure 6-38 shows how the carbon emissions of the studied electricity system change as CSP capacity increases with and without a carbon price. The change of slope in the graph in the case without a carbon price is apparent around the 14GW point. This corresponds to the point where a similar change of slope is apparent in the rate of change of coal generation decrease. With a carbon price, CSP capacity leads to an increase in carbon emissions as nuclear capacity is not constructed and gas generation is increasingly utilised. With further increases in CSP capacity gas is increasingly displaced and the CSP entering the system

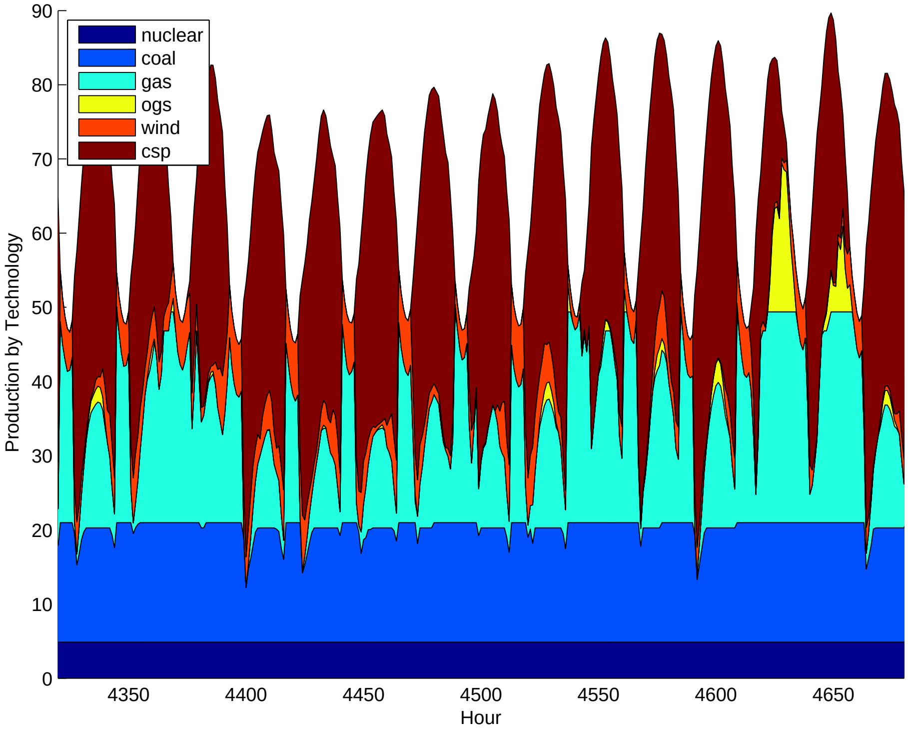

Figure 6-37: Production Profile for 15 Sample Summer Days (37% of annual electrical energy provided by CSP)

leads to a further reduction in carbon emissions.

The importance of what technology solar, or any renewable technology, displaces in terms of its impact on carbon emissions is again illustrated by this figure.

6.4.4 Nodal Pricing

Figures 6-39 and 6-40 show the comparison between price duration curves for the cases with no CSP capacity and 24.5 GW of CSP capacity installed respectively. Similar to the PV deployment cases, a broad decrease can be seen in the average nodal price and in particular the price at the node where the majority of the CSP capacity is installed, node 61. However there is a difference between the nature of the price reduction. In the PV case, the 'steps' in the curve tend to shift to the left. In the CSP case, it is a more gradual reduction. For example, in the CSP case, due to the ability of CSP energy to be stored, the price does not reduce to zero for a certain number of hours (as in the PV case), but the price reduces a smaller amount across a greater number of hours.

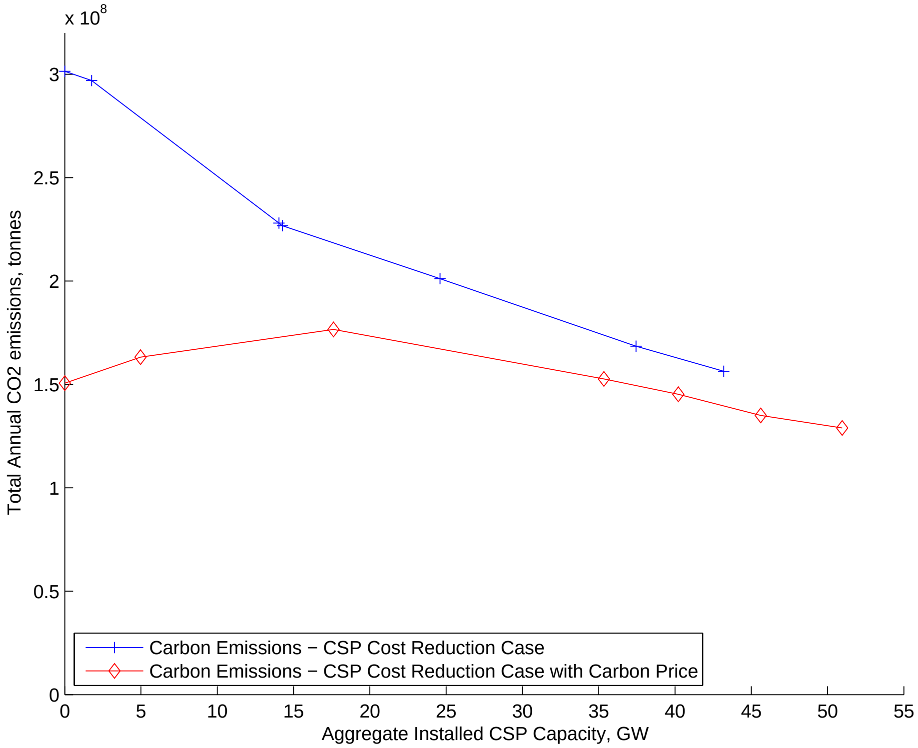

Figure 6-38: Carbon Emissions versus CSP Capacity (with and without a carbon price)

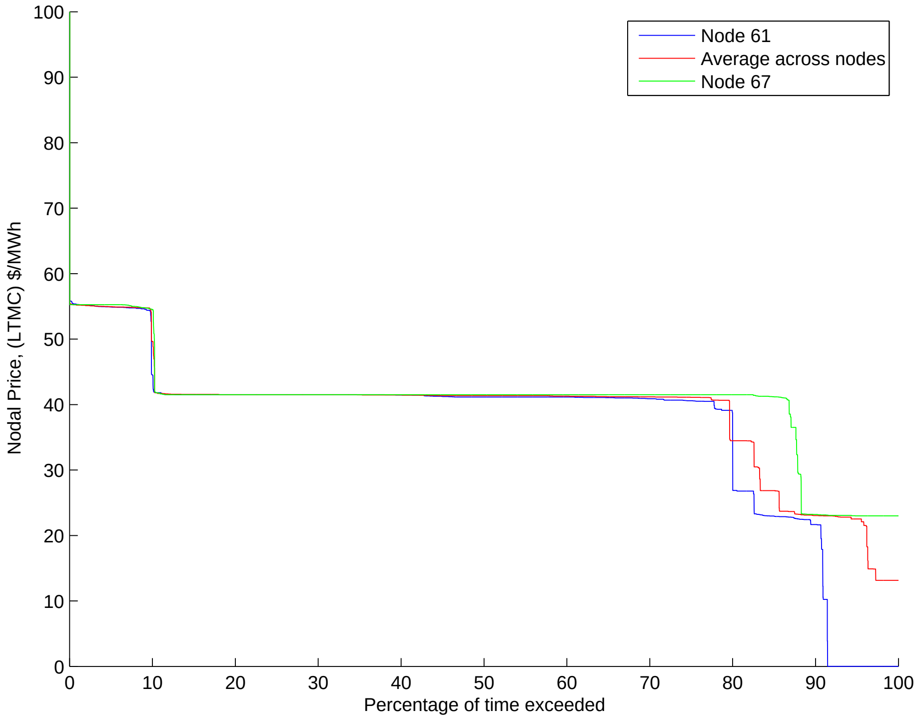

Figure 6-39: Price Duration Curve - Base Case (0GW CSP capacity)

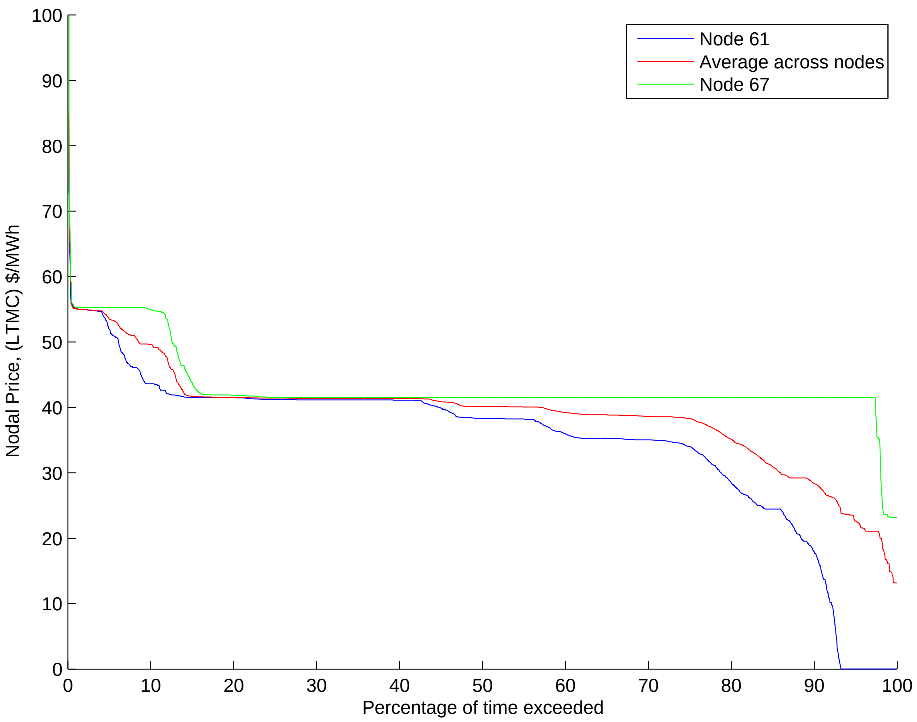

Figure 6-40: Price Duration Curve (24.5GW CSP capacity)

6.4.5 Components of Objective Function

Figure 6-41 shows the evolution of the relative weighting of the components of the objective function as the cost of CSP decreases and it enters the system. Initial savings in the operation of the conventional system can be seen in run 5 where initial CSP penetration leads to a decrease in gas related costs. However as the CSP quantities continue to increase, system savings start to come from savings in baseload operating, and in particular, fixed costs. Also, there is not an increase in gas operating costs as was noted in the PV case.

6.4.6 Discussion

- CSP enters the system at a higher cost per MW than was the case for PV. This is partly attributable to the higher capacity factor the storage allows (for example 0.49 in solar-61), but also the ability of CSP to be dispatched in such a manner as to maximise system value.

- Similar to the photovoltaics cases, quantities of CSP capacity entering the power system lead to a reduction in base load capacity. Dissimilarly to the PV cases, CSP

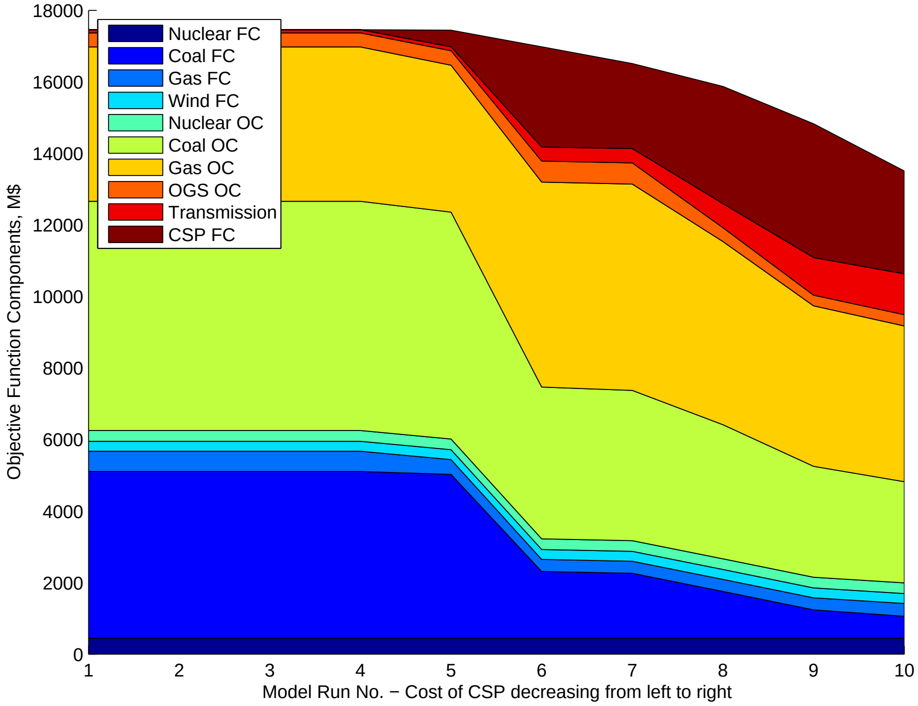

Figure 6-41: Change in Objective Function Components Across CSP model runs

capacity entering the system does not 'bring' gas capacity (and associated generation) with it. This can be attributed to the dispatchable nature of the technology, and the ability of the technology to capture a greater proportion of peak demand.

- The model installs a significantly greater quantity of transmission in the CSP cases than the PV cost reduction cases. This is partly a function of the CSP being more locationally constrained, but is also related to the higher capacity factor of the CSP facility.
- As a related point, considering the production profile presented of days with CSP, it is apparent that the model utilises the storage capabilities of the CSP plant in order to cover the whole peak demand of a given day.
- A different impact on the price duration curve was noted for CSP cases relative to the PV cases, with the price reducing by smaller amounts across more hours.
- It is clear from the results that CSP provides different services to the electricity sector. Electricity from solar energy thus has different implications for the power system depending on the technology in question.

- The RPS versus cost reduction deployment paths were not as divergent as these paths were for PV.

Finally, it should be noted that CSP model outputs are more sensitive to design assumptions (size of collector area, reference insolation value and quantity of storage) than is the case for PV (where direct current produced is directly proportional to insolation). Thus the study of the implications of CSP has many possible further avenues of exploration.

6.5 A Note on Baseload Displacement

One finding throughout the suite of runs above is that the large-scale deployment of CSP and non-dispatchable variable PV onto electric power systems displaces constantly running baseload capacity, when comparing across static optimisation outcomes. As this is perhaps a non-intuitive finding, before leaving this chapter the following reasoning is provided to explain this result:

- Considering the high capital costs of coal or nuclear generation relative to gas generation, it is not economical to construct baseload if the number of hours of the year it is dispatched decreases. Once wind or solar capacity is on the system - it is then free to produce and will take priority in the dispatch. As the quantities of these technologies on the system increase in the model, it is no longer attractive to construct baseload capacity as some of the hours it would have been producing are now being filled by renewables.

- An interesting way of illustrating this is by using the screening curve methodology, a methodology that allows the utilisation factors of technology type to be estimated based on their fixed and variable costs. The point where the utilisation factor for a technology crosses the load-duration curve indicates the optimum capacity investment for this technology [5]. Applying this to our earlier derived net load-duration curve produces Figure 6-42, where it is apparent that the optimal quantity of installed baseload capacity decreases as the load duration curve shifts downward with PV deployment.

  Folded into this curve are all the complexities of variable photovoltaic production and associated transmission requirements and constraints.

- Another way of looking at this is to consider the price-duration curves. From previously, the optimality conditions require $FC = (\sum_h(\lambda_h - CVR))$, indicating that the fixed costs are only recovered when the system price is greater than the marginal cost at the generator's node. Thus the changes as noted to the right hand side of the price duration curve will negatively impact baseload technology (more so than gas technology).

A point to note is that if no baseload technologies are constructed in the base case, then the model, which does not include retirements, will displace the gas generation that was constructed. This has an associated effect on emissions and the realisable conventional system cost savings brought about by renewable energy. A question for electricity systems facing large quantities of renewables is whether the technology mix can adapt in the long term to this new paradigm.

There is much a static optimisation model does not capture as decisions and investments are made on a dynamic basis across time with systems that include existing capacity with long economic lives. Some further thoughts are provided following a preliminary assessment undertaken with the ReEDS model in Chapter 7.

6.6 Chapter Summary

In this chapter the results of the application of the Expan model to the ERCOT system were presented.

The first section of the results applied realistic numbers to the analytical findings of Chapter 5. In so doing, the components that constitute the marginal value of a renewable generator under transmission constraints and under renewable support policies were analysed. Different from a conventional generator, the pattern of available production of the renewable generator was an important component. The differentiating factor between wind and PV in this analysis was the respective production factor of each. As the actual numeric impact will depend on the particular system, the application of the framework highlighted the possible benefits of thinking about these system components together. For example, PV slightly increased the marginal value of wind while the opposite did not occur.

The next section of the chapter then compared the static optimisation outcomes across a series of photovoltaic deployment runs - PV entering the system through cost reduc-

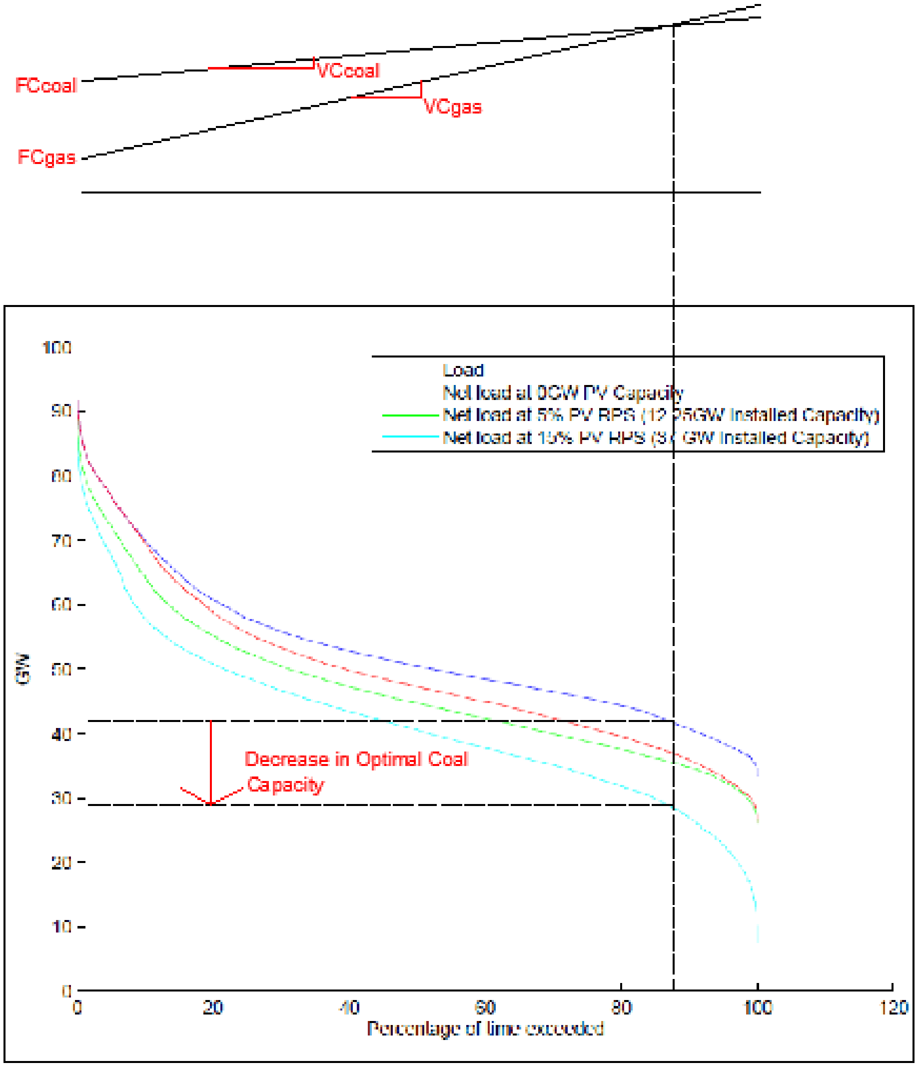

Figure 6-42: Screening Curve Methodology Applied to PV Load Duration Curve

tions, PV entering the system through RPS standards, and these same scenarios including a carbon price. PV entering the system by cost reductions entailed a spatially distributed pattern of investment with a limited increase in transmission investment, whereas PV entering the system by an RPS or FIT scheme entailed an investment pattern concentrated at the locations of the best solar resources, thereby requiring associated increases in transmission investment. In both cases, baseload capacity was displaced, representing avoided conventional capacity not constructed. The PV case entailed an increase in gas capacity to complement the PV which had entered the system. Under a carbon price, nuclear energy was the baseload technology displaced. Noticeable shifts in the price duration curves of the system were noted with PV deployment.

The next section of the chapter then considered CSP deployment. The nature of CSP technology is such that it is confined to areas of the best solar resource thus the distributional differences between the RPS and cost-reduction cases were not so relevant. The benefits of thermal storage in the CSP plant were apparent with the ability to have a higher capacity factor and also meet the whole peak portion of daily demand as opposed to solely a portion as in the case of PV. A similar impact to the PV results on baseload capacity was noted while CSP had a different impact on gas capacity and generation (displacement of gas capacity). In addition, due to the accompanying storage, CSP had a different impact on the price duration curve than was the case for photovoltaics.

The results that span this chapter indicate many economic, regulatory and technical implications that may be associated with large quantities of solar electricity technologies entering a power system.

Technical

While not considering them explicitly, the results of the chapter provided an indication of the technical challenges facing a system with large quantities of solar electricity capacity. More flexible conventional generation, control strategies of the power system, maintaining power quality, maintaining a synchronous grid, the choice between DC and AC transmission lines - all these technical challenges and more underlie the scenarios presented here.

Economic

What technologies to invest in to meet the electricity demand of the future are decisions that must be made far in advance considering the long economic life of projects. The possible economic implications for different generation technologies in a world with large quantities of solar electricity on power systems have been laid out.

Regulatory

The difference in outcomes between diverging paths of solar power deployment would appear to be a relevant issue for policymakers considering the support of solar power specifically.

Under all solar power deployment scenarios, transmission was constructed depending on what the cost-minimising path turned out to be. Under a market environment who makes the decision to invest, and who pays for it is a complex issue. Considering the importance of appropriate transmission planning for solar power deployment, this issue is addressed in detail later in Chapter 8.

Chapter 7

Application of ReEDS Model

7.1 Introduction and Qualifications

As previously noted (Section 6.1.2), there are many aspects of the capacity expansion of power systems that the Expan model does not incorporate. This relative lack of complexity allows the model to provide insights into the interactions of the primary system variables, and the trends across results are of greatest relevance as opposed to the absolute numbers. A more detailed model is required if there is a wish to include additional real-world considerations. These considerations can range from treatment of financing to the evolution of capacity value to the inclusion of operating reserves.

One such model that incorporates these considerations (in addition to many more) is the ReEDS model, developed at NREL. As noted in Section 4.1, as part of this research process, the author spent time at the NREL facility in Colorado to learn about the structure and operation of the ReEDS model.[1]

To further the insights gained with the simple Expan model, and to present a sample of the output of a larger scale model that addresses similar questions, the ReEDS model was employed to consider a number of scenarios. Specifically, the capital cost pathway of photovoltaics was uniformly reduced across a series of runs and the subsequent outputs were compared. To align with the Expan model runs of Chapter 6, the ERCOT component of ReEDS was used. In addition, both for illustrative purposes and to determine if similar outcomes were noted beyond the ERCOT system, ReEDS was applied to the USA system as a whole.

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[1] The ReEDS model documentation can be found at [65]

Before consideration of the ReEDS results, a disclaimer is made. There are many differences between the ReEDS model and the Expan model, and thus their outputs are not directly comparable. This even applies to basic common input parameters such as load growth and technology cost. For example ReEDS requires a demand forecast for its 17 dispatch timeslices for each 2 year period, while Expan requires a demand forecast for 8760 dispatch hours for 1 static optimisation period. Similarly, ReEDS requires a technology forecast for each 2-year period whereas Expan requires a single capital cost number. In addition, ReEDS uses a supply curve to determine fuel costs whereas in Expan the variable cost of electricity production by technology is deterministically input. Many other differences exist which complicate comparison, with a further example being the presence of additional technology choices in ReEDS.

Thus, the value of this exercise may not be the results provided but rather an illustration of the sensitivity of expansion model outcomes to structure and input assumptions. In this context, any further insight gained into the implications of solar power deployment can be considered a bonus.

7.2 ERCOT ReEDS Results

7.2.1 Generation Capacity Investment

Figure 7-1 shows the 2030 installed capacity for each technology as a function of uniform reductions of capital costs of photovoltaics in the period from 2006 to 2030. Figure 7-2 shows the change in installed capacity of each technology between 2006 and 2030 as a function of PV capacity. Note that for the purposes of clarity, in these figures and in the following figures of this section, a number of the technologies that are included in ReEDS that do not play a large role in the cumulative system are removed. These technologies include landfill gas, biopower, coal-ccs, coal-igcc, gas-cc-ccs, geothermal energy and ocean energy.

It is noticeable that different outcomes are observed compared to the Expan model results, including the base case. In particular, no new baseload capacity (coal or nuclear) is installed in the ReEDS base case. This could be due to a number of factors - a) gas generation is able to contribute more than baseload to the operating reserve requirements of ReEDS (note that operating requirements are not included in the Expan model), b) ramping constraints on coal generation from one timeslice to another exist in the ReEDS

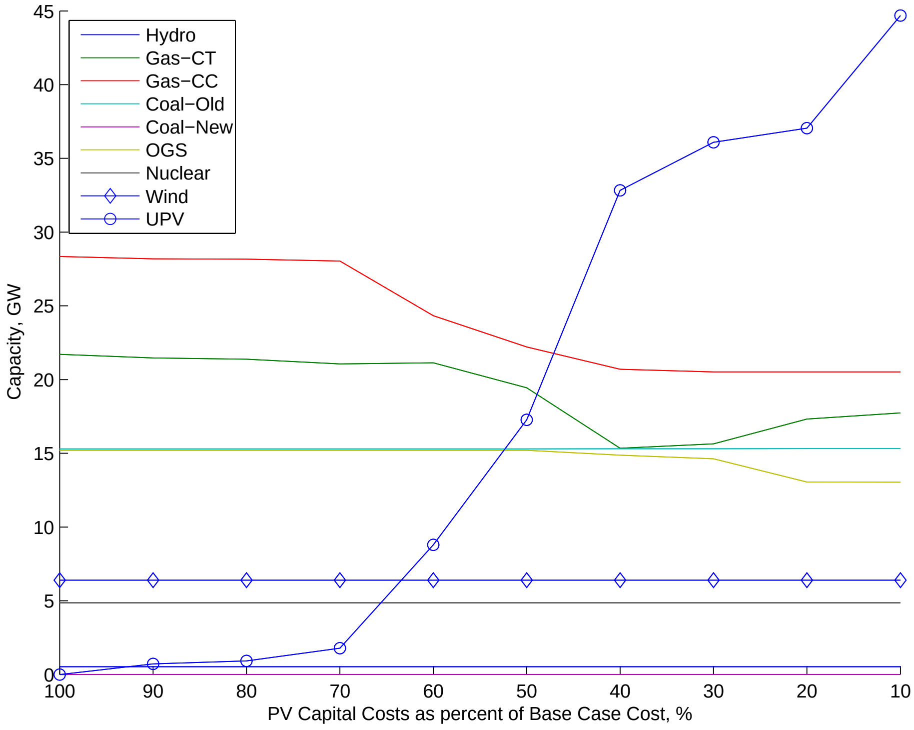

Figure 7-1: 2030 ERCOT ReEDS Installed Capacity versus Declining PV Capital Costs

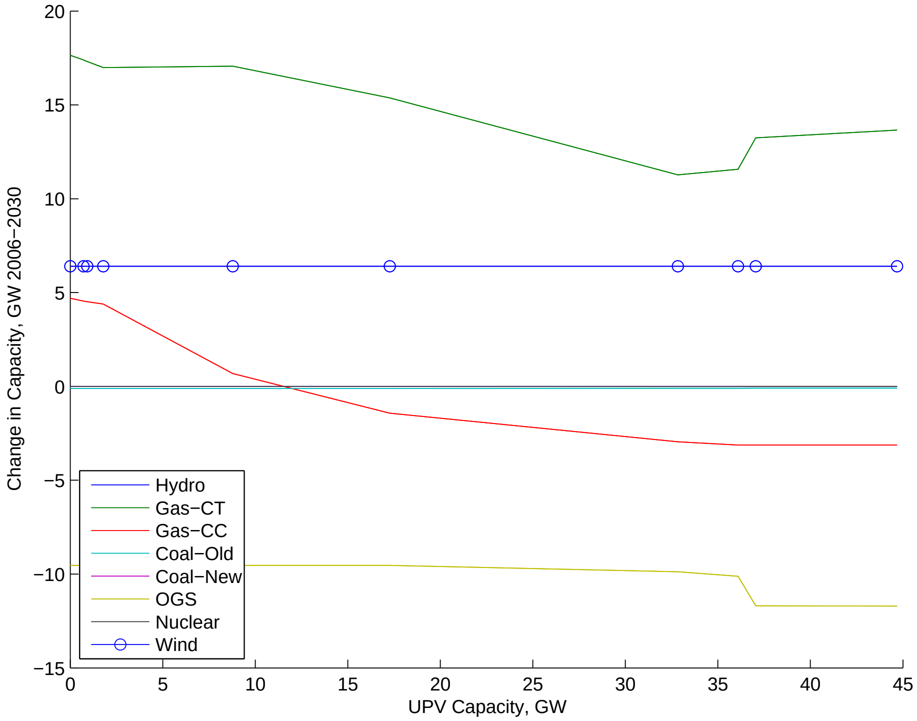

Figure 7-2: Change in Capacity by Technology from 2006 to 2030 versus 2030 PV capacity

model (and not in the Expan mode) and may discourage investment in coal relative to gas, c) environmental constraints that impact on coal to a greater degree than gas generation exist in the ReEDS model, constraints that do not exist in the Expan model - namely SO_2 and NOX constraints, d) the peak demand for 2030 in the ReEDS model is 80GW while peak demand for 2030 in the Expan model is 90GW (due to different load growth assumptions), leaving less room for investment in coal capacity in ReEDS, and e) gas - combustion turbine (gas-ct) technology is a low capital cost technology included in ReEDS that is not included in the Expan model.

Thus as photovoltaics enter the system, the investment in gas capacity is avoided. In addition, some gas - combined cycle (gas-cc) units are retired as increasing quantities of photovoltaics enter the system.

Considering the findings earlier in the thesis about baseload capacity being replaced, it is a valid question to ask why the existing baseload capacity is not retired, considering the ReEDS model includes retirements. The primary reason is likely to be the long economic lifetime assumed in the model for coal and nuclear plants, 60 years. Once an investment has been made, it is very competitive with any new potential investment. In addition, the modelling of coal plant retirements in ReEDS is explicitly linked to the economic tradeoff between the costs of operating the coal plants and the costs of building and operating gas-cc units (and thus not directly linked to the costs of renewable generation).

Considering Figure 7-1, it is noticeable that as the cost of PV reduces, the rate of deployment decreases. This is in contrast to the Expan model, where the rate of deployment rapidly increased as the costs decreased. In addition, the absolute capacity of PV installed as the costs decrease is of a lower quantity than in the Expan model. Constraints included in the ReEDS model in relation to solar power deployment that may account for this discrepancy are penalties on growth in period-on-period capacity exceeding a certain limit, and a cap on the available solar resources within each spatial area. This is noteworthy as some of the insights of the Expan model related to occurrences at these very large quantities of installed PV capacity ($> 45GW$).

Figure 7-3 shows the distribution of installed PV capacity. Similar to the Expan case, as costs decrease the distribution of where the PV is installed becomes less concentrated on the high-quality western nodes of the system.

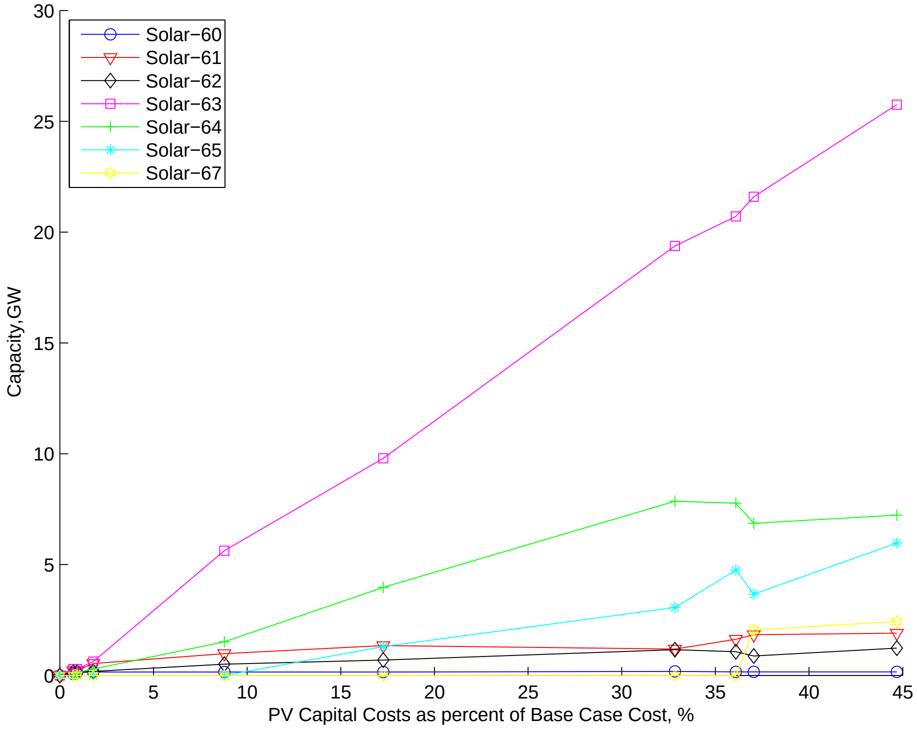

Figure 7-3: Distribution of Installed PV Capacity

7.2.2 Operation and Dispatch

Figure 7-4 shows the cumulative generation by technology on the system as the costs decrease. Similar to the capacity figure, gas-cc generation declines with increasing PV generation. Unlike the capacity figure, the relatively low impact on gas-ct generation can be noted. Gas-ct can be seen to be very much a capacity resource in the ReEDS model outputs.

Figures 7-5 and 7-6 show the generation profile across the representative timeslices in the ReEDS model for a case with no installed PV capacity and a case with circa 34GW installed PV capacity. These figures provide some insight into why gas-cc generation is displaced by photovoltaics. While all gas technologies are displaced at the superpeak, it is at the timeslices of greater duration that PV capacity displaces gas-cc (see hours 6, 7, 10, 11, 14 and 15). In addition, as ReEDS assigns a capacity factor per timeslice to PV generation, the time periods are not captured where PV is operating closer to nameplate capacity and thus potentially displacing coal or nuclear generation.

As a further example, consider ReEDS timeslice 15 which represents 2pm-5pm in the Spring. We have seen previously (Figure 6-17) how the PV production can vary over that timeframe, at times providing a significant proportion of instantaneous generation.

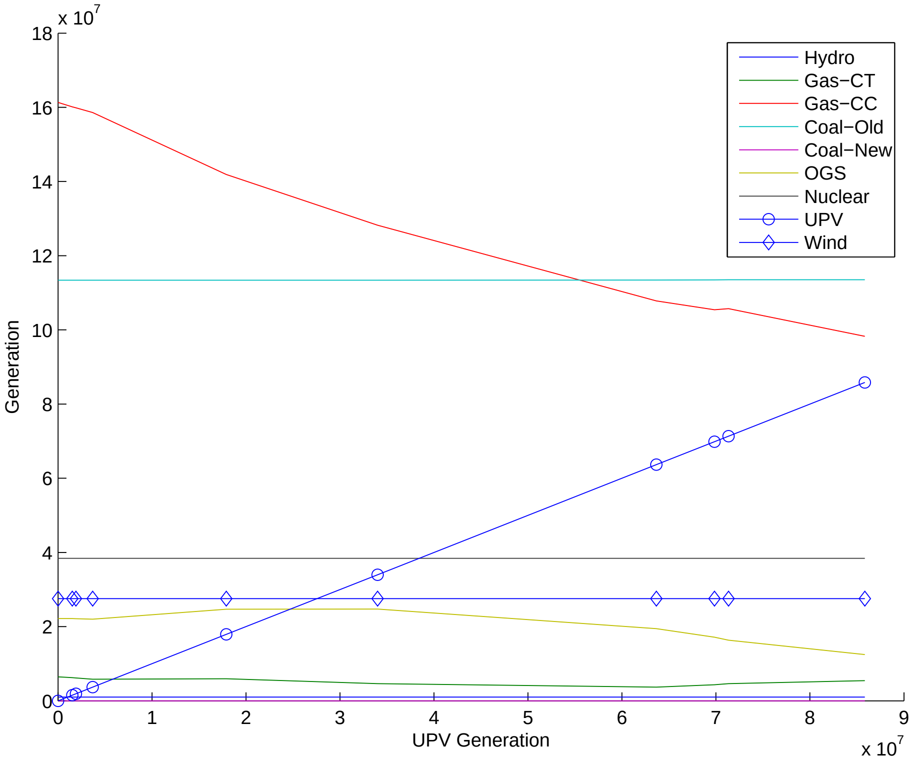

Figure 7-4: 2030 ReEDS Generation by Technology versus PV Generation

These figures thus portray how with 17 timeslices, it can be difficult to capture the hours when PV is producing at peak (or indeed the daytime hours when PV is producing close to zero), highlighting the tradeoffs across model structures.

Considering the interest of this thesis in solar power, and that one of the primary factors of interest to this topic is its production pattern, these figures portray why the Expan model was developed for the purposes of this thesis in place of the use of a more-established and tested model.

7.2.3 Evolution Across Time

In order to provide a representation of the dynamic optimisation process that ReEDS follows, Figures 7-7 and 7-8 show the evolution of the system across time for two cases of cost reductions.

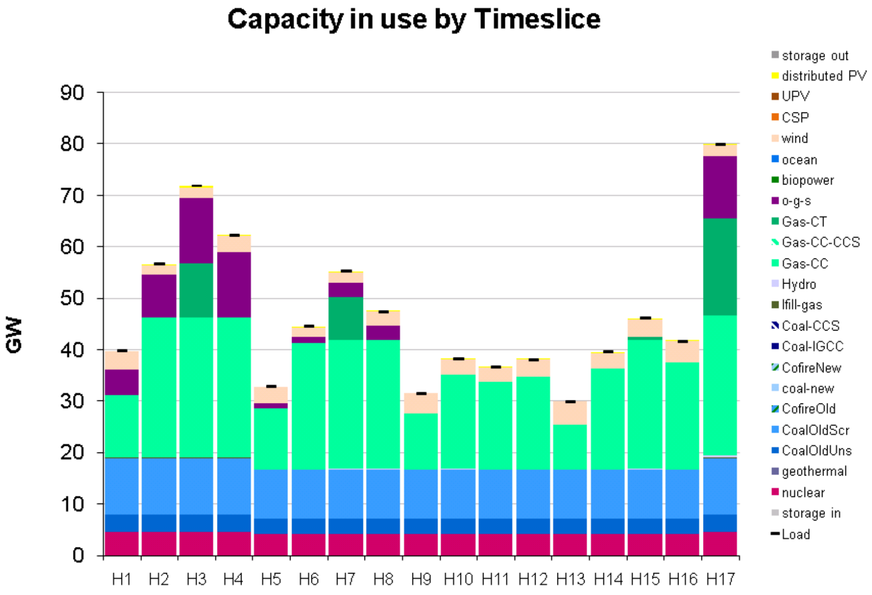

Figure 7-5: ReEDS Generation Profile for 0GW of Installed PV Capacity in 2030

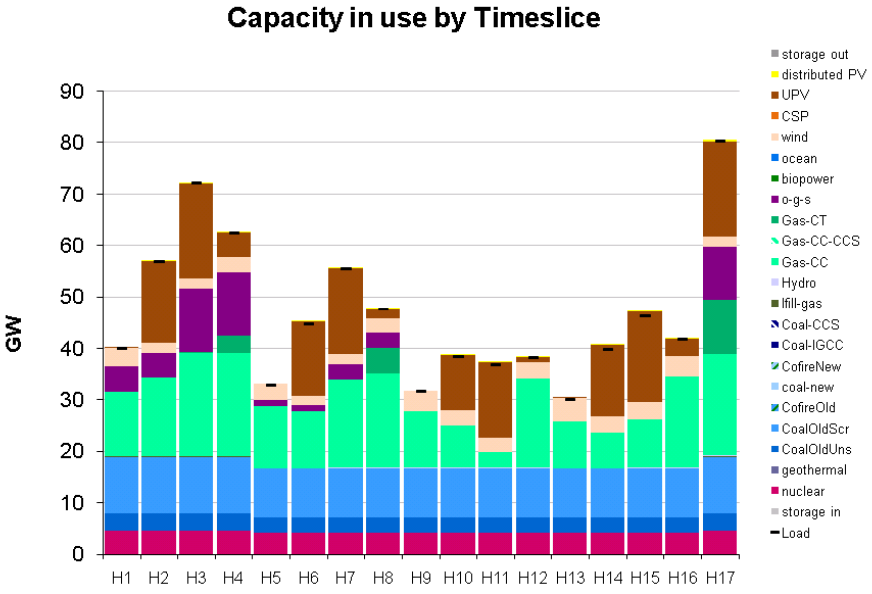

Figure 7-6: ReEDS Generation Profile for 34GW of Installed PV Capacity in 2030

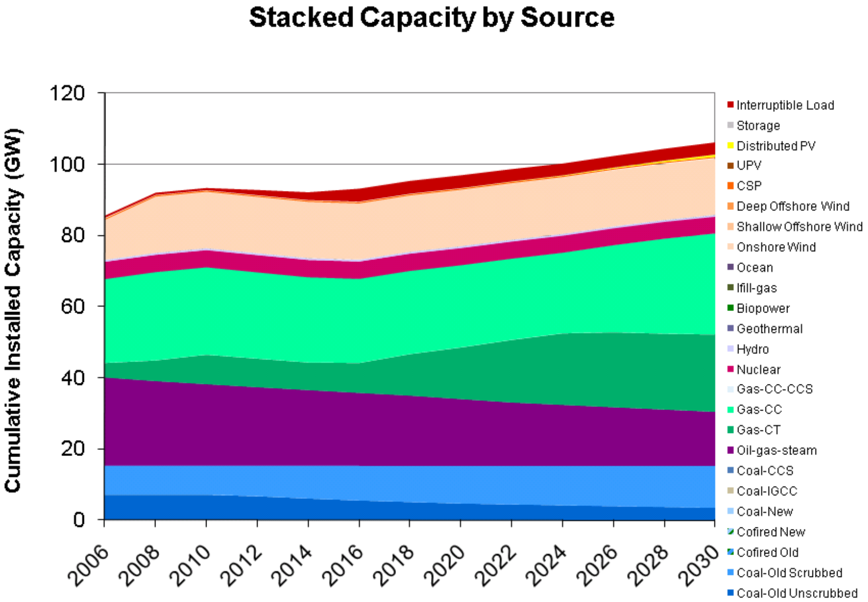

Figure 7-7: Evolution of Installed Capacity for Base Case PV Costs

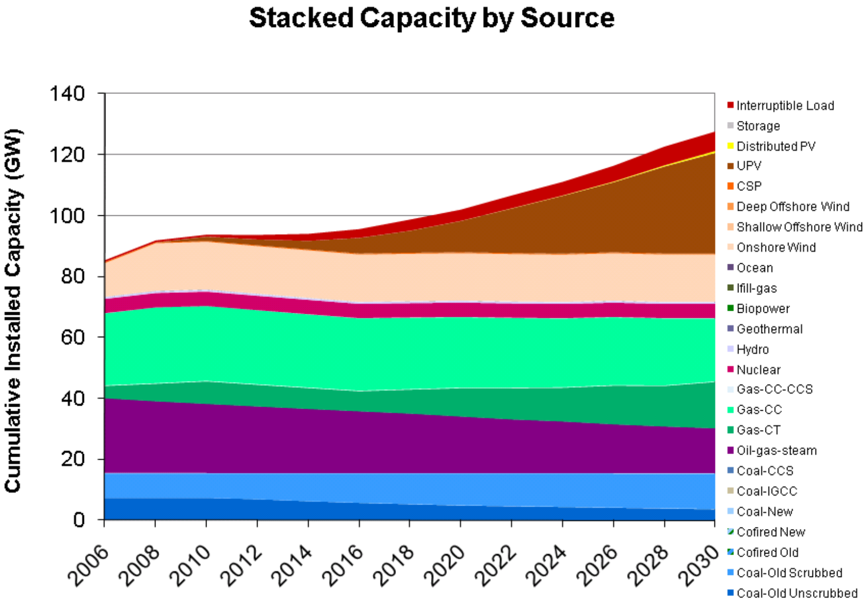

Figure 7-8: Evolution of Installed Capacity for Case with 60% Uniform Reduction in PV Cost Pathway

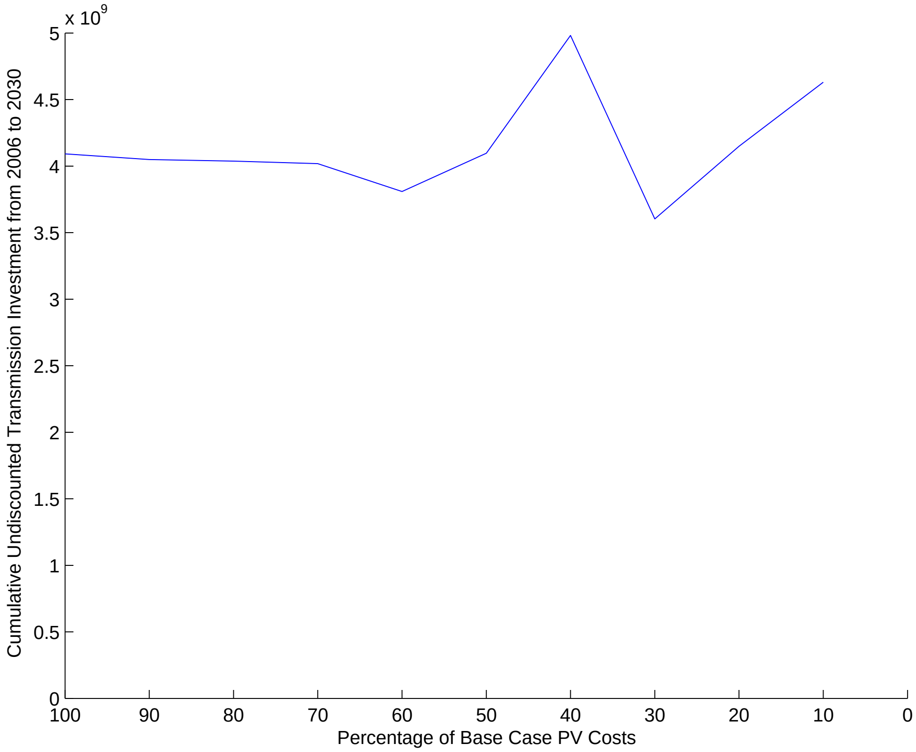

Figure 7-9: ReEDS Transmission Investment versus Declining PV Costs

7.2.4 Transmission Investment

Figure 7-9 shows how transmission expenditure compares across the different cost reduction model outcomes. Similarly to the Expan PV cost reduction case, as PV costs reduce, a more distributed profile of photovoltaic installation is followed. Here, transmission investment generally does not increase, highlighting the distributed role ReEDS assigns to photovoltaics. Note that ReEDS employs a ‘transportation’ model representation of the transmission network.

7.3 USA Results

Figures 7-10 and 7-11 show the results of applying reduced costs of photovoltaics across the whole U.S. system as modelled in ReEDS. Broadly similar results can be noted as for the ERCOT case. One exception is that a small amount of coal capacity retirement is noted at the highest quantities of installed PV capacity. Coal generation can also be noted to decrease when increasing quantities of PV enter the system. Again, coal or nuclear capacity expansion does not feature prominently in the base case.

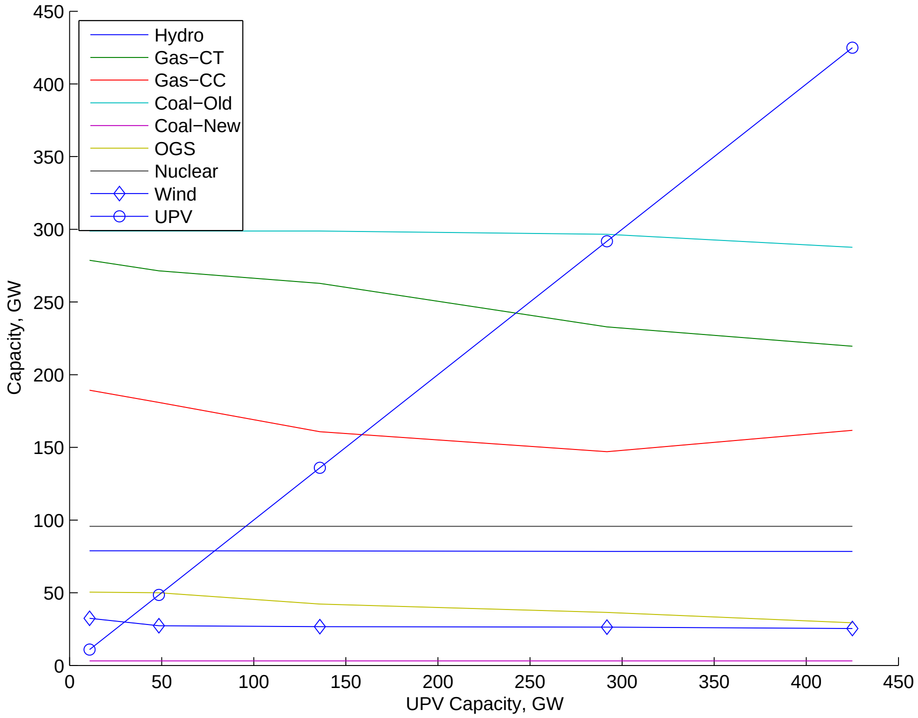

Figure 7-10: 2030 USA ReEDS Installed Capacity versus Declining PV Costs

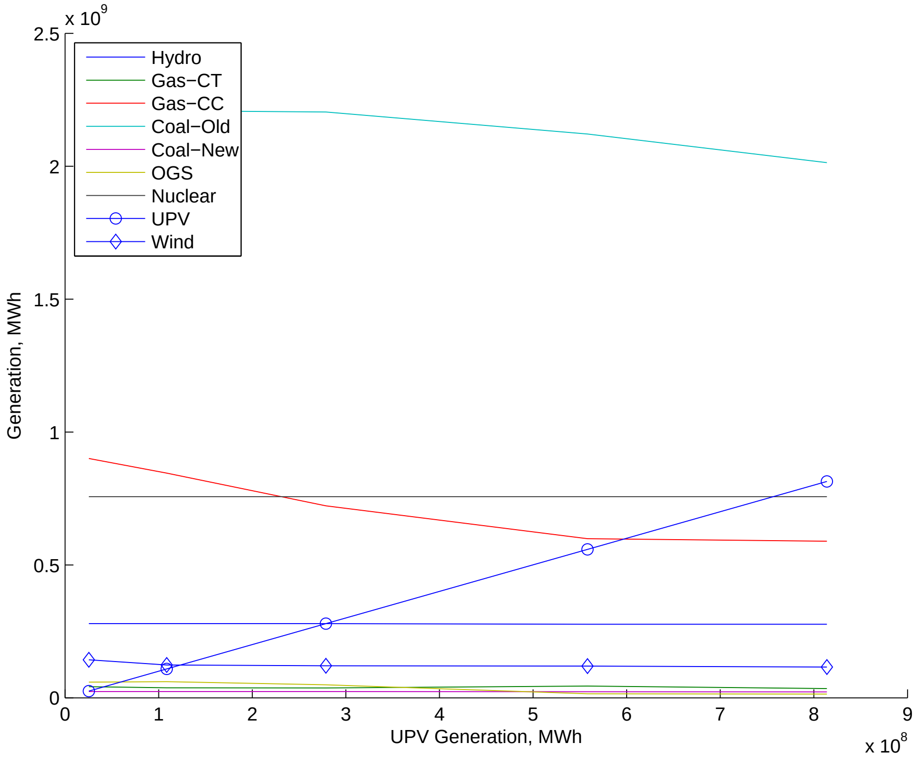

Figure 7-11: 2030 USA ReEDS Generation by Technology versus Declining PV Costs

7.4 Chapter Summary

- ReEDS is an extensive model developed over a number of years at NREL, and has been used in a significant number of publications.[2] The use of ReEDS in this chapter was not designed to reflect that of a full systematic analysis, but rather to provide a suite of illustrative results of an ‘industrial-grade’ model in the same category as the developed Expan model.

- As may be expected considering the differences in model structure, different outcomes are noted across the models. In the ReEDS base case, no coal or nuclear capacity is constructed, but largely gas capacity. Thus, investment is avoided in this gas capacity as photovoltaics enter the system. This highlights how the impact of solar power on the optimum technology mix (and associated emissions impact) depends very much on what new investment would occur if solar power did not enter the system - this base case is subject to much uncertainty.

- Use of the ReEDS model highlighted how once capacity is installed in the power sector, particularly baseload capacity, there is a strong incentive to remain on the system for a long time.

- Use of the ReEDS model highlighted one of the important tradeoffs present when designing capacity expansion models that include renewable power sources - the degree of temporal resolution included.

- Broadly similar results were returned for the U.S. system as were returned for the ERCOT system as a whole.

- In order not to complicate the thesis unduly, and for the sake of coherence, it was decided not to extend the ReEDS model to the many other questions it could answer - for example concentrating solar power, the consideration of solar power deployment under different policy options and the U.S. distribution of installed capacity, amongst others. These could all be major works in themselves, and are a sample of the questions the NREL developers apply, and will apply, to the ReEDS model. Use of the model here has allowed further consideration of the implications of solar power deployment,

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[2] For a list of associated publications, see [87].

and has allowed the relatively simple Expan model to be compared with a more mature model of the same category.

Chapter 8

A Focus on Transmission

This chapter focuses on the issue of electric power transmission - a) stating why it may be of particular interest to solar energy, b) outlining what constitutes the capacity of a transmission line, c) discussing the source of transmission charges, d) assessing cost allocation methodologies, and their respective attributes in the context of large-scale solar power deployment and e) studying the role of transmission charges on renewable generators in a market environment.

Under a traditional, centralised, vertically integrated utility framework, the decision on which transmission facilities to invest in can be made with the goal of globally minimising the system-wide costs and benefits. In the market framework however, who decides to build what transmission where and who foots the bill is a regulatory issue of ongoing concern. This issue has become increasingly important as new renewable generators, frequently supported by public policy, wish to access existing and future transmission systems.

Transmission has thus moved from being a necessary component of the series of actions required to efficiently meet the singular objective of supplying electricity demand within a decision maker's area to being the meeting point of supply and demand of many agents within regional, national, or international electricity markets.

This latter role implies that due to the transmission network's potential influence on market access, market power and geographical extent of competition, the appropriate regulation of transmission activities is thus essential for the maintenance of well-functioning electricity markets (and consequently the efficient deployment of solar and wind power).[1]

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[1] A comprehensive discussion on the role of transmission in the context of past and present transmission policy in the United States is available at [88] and [89].

8.1 The Relevance of Transmission to Solar Power Deployment

As outlined by [90], the underlying reason why transmission is particularly relevant to solar energy (and wind energy) is that unlike other energy sources, the only current practical means of transportation from the areas of highest quality resource to areas of energy demand is by the transmission of electrical energy. This is different to the situation of coal, liquified natural gas and uranium which can be delivered by rail, sea, and road, and also different to the situation of natural gas which can be delivered by pipeline.

It makes economic sense to install CSP facilities or large-scale PV facilities in the areas with the best solar resource, and where land is cheapest. This dual consideration frequently leads the choice location for large scale solar power facilities to be away from the electricity load centres, thus requiring transmission (both shallow and deep upgrades) to incorporate the facilities onto the grid.

As shown in the results of Chapter 6, increased transmission investment beyond the base case was noted in all solar power deployment scenarios, with particularly large investments noted in CSP deployment scenarios or when photovoltaics were brought into the system by an RPS or feed-in-tariff policy. Considering this important role for transmission in the cost-effective deployment of solar power technologies, this chapter focuses on the technical, economic, and regulatory issues related to solar power and transmission.

8.2 The Capacity of a Transmission Line

Much of the discussion in relation to transmission of renewable energy relates to how many MW of power a new transmission line could transport from area A to area B, in effect the ‘available transfer capacity’. The analytical and numerical modelling of Chapters 5 and 6 essentially treated transmission in this respect. However, this is a simplification of the physical laws that govern the operation of power systems, where the power transferred between two nodes relates to the angle and magnitude of voltage at each end of the line, the resistance of the line, the self- and mutual- inductance of the transmission line conductors, and the capacitance of the line. In addition, network flow adds complexity to the situation. This subsection thus seeks to lay out what governs the capacity of an AC transmission line to transmit electric power.

The power transfer capacity of a transmission line is determined by a number of different, inter-related factors. Similarly to a water pipeline, or a bridge across a large river, the transfer capacity of the transmission line depends on static properties such as geometry and constituent materials. Dissimilarly to bridges or water pipelines, the capacity of a transmission line is also related to temporal and spatial varying effects that are external to the line itself. As per [91], all of these factors are broadly categorised as the following; a) thermal constraints, b) voltage constraints, and c) system operation constraints.

8.2.1 Thermal Constraints

The thermal limit of a transmission line is one of the fundamental limits on its power transfer capacity. Essentially, the line must be prevented from overheating. Overheating can cause two problems a) excessive line sag between transmission towers, and b) reduced life expectancy of the line.

Excessive line sag is a problem as it can (i) create a safety hazard and (ii) greatly increase the chance of a line fault - for example a sagging line could touch a tree, leading to a line outage. In addition, thermal expansion of a material can be both temporary and permanent in nature. [4] identifies approximately $100°C$ as the point where thermal expansion can become permanent on a transmission line.

[91] indicates that thermal expansion of a line can reduce the strength of the transmission line conductor material, thus reducing the life expectancy of the conductors.

Overheating derives from the fact that flowing current in a conductor produces I^2R losses. These losses are dissipated in the form of heat, heat which raises the temperature of the conductor, potentially leading to the undesirable effects described above. As R can be considered fixed for a given transmission line, it is thus the current, I, that is the critical factor in determining the thermal limit of a line. Transmission lines thus typically have a ‘rated current’ associated with their operation, a current that is not allowed to be exceeded during normal line operation. The ‘actual’ real-time current rating of a line however is variable as the actual temperature of the line conductors is a function of the local weather conditions’ ability to dissipate the heat generated. This ability is itself a function of ambient temperature, wind speed and wind direction. In addition, the ground clearance requirements can vary from location to location. Thus setting a rated current is not necessarily a trivial exercise, however the standard design paradigm is to design for the worst case conditions. Thus, many transmission lines are also assigned ‘emergency ratings’ - the allowance of increased current flow for a short period of time (before the temperature rises too much) at times when the grid is under tight operating conditions.

Finally, before leaving this section, [4] note that; “thermal limitations on terminating equipment (such as transformers) may be more restrictive than those pertaining to the line itself”’

8.2.2 Voltage Constraints

Transmission lines are often defined by their voltage ratings. Significant deviations from this voltage rating across the line can create problems. For example, if the maximum voltage of a transmission line is exceeded, [91] outline how short circuits, radio interference and noise may occur. In addition, transformers and other components of substations could be damaged. Low voltages on the other hand, can cause “inadequate operation of customer’s equipment and may damage motors” [91].

Voltage across a transmission line generally drops from the sending end to the receiving end, due to reactive power flows and line reactance.[2] As the inductance of a transmission line is typically expressed in Henrys/m, it is clear that this is a greater issue for longer lines than for shorter lines. Why voltage drop across a line is a potential problem is discussed below.

Thus the power transfer capacity of a transmission line depends on the maximum and minimum allowed voltages for a particular line and associated transformers and substations, in addition to the voltage drop which may occur along the line due to the line’s inductance.

8.2.3 System Operation Constraints

This is a broad category of constraint on transmission capacity further divided into a number of categories below:

Reactive Power: If there is a significant amount of reactive power required on a system, the transmission line will have decreased ability to transfer active/real power.

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[2] Under unusual circumstances rarely encountered in power system operation, the voltage at the receiving end can be higher than at the sending end (termed the Ferranti effect). These circumstances include when the line is charged but there is a very light or disconnected load at the receiving end [92].

Network Flow: The path of power flow from source to load depends on the impedance of various paths, with more power flow along a low impedance path. A proportion of the transmission capacity of a transmission line could potentially be utilised by flows from different control areas or jurisdictions, potentially reducing the available remaining capacity from expected.

System Security: Grid codes generally dictate that there is redundancy within the power system to deal with any contingencies that may occur. An 'N-1' criterion for example would require that the system be able to stay operating should any generating unit or transmission line fail. This standard can limit the available capacity of a transmission line so that it can handle additional current should a neighbouring line or generating unit fail.

System Stability: A broad category including a number of sub-categories which [93] outlines as transient stability, dynamic stability, steady-state stability, frequency collapse, and subsynchronous resonance. The following paragraphs consider the complimentary categories of rotor-angle stability and voltage stability.

Essentially, system stability considerations relate to a concern for maintaining synchronisation on the power grid. Equation (8.1) shows that power flow is maximised on a line without resistance when $sin\theta_{ij}$ is equal to one, indicating maximal power flow on such a line is achieved at a phase angle of 90°. [4] however note that to maintain "reasonable expectations" of maintaining synchronism in the event of a fault the maximum values should be in the region of 40° to 50°, thus limiting the "stability limit" to 65% ($sin 40°$) - 75% ($sin 50°$) of potential capacity.

$$P_{ij} = -P_{ji} = \frac{|V_i|\,|V_j|}{X_{ij}} sin\theta_{ij} \tag{8.1}$$

Related to the reactive power considerations above, voltage stability maintenance is another factor in the power transfer capacity of a transmission line. Line inductance and reactive power flow can lead to drops in the voltage at the load. [43] describes how providing the same power at this lower voltage increases current drawn by the load (as $P = IV$), which in turn causes additional reactive power flows and voltage losses in the system. This feedback loop tends to instability and the voltage on the system can collapse. Thus this stability concern feeds back into capacity requirements related to reactive power and voltage levels on the line.

Which of the many factors above are binding in determining the capacity of a transmission line varies depending upon circumstances over short, medium and long timescales. However, a pattern emerges in the above text, with line length having a large influence on what factor is binding. In particular, [4] makes the statement that generally, for short lines, the thermal (current rating) limit binds, while for long lines, it is the ‘stability’ related limits that prevail. Additionally, voltage drop can be limiting for lines of intermediate length.

Following this consideration of the technical issues related to the capacity of a transmission line, the focus of the chapter shifts to economic and regulatory issues in the discussion of the efficient interaction of transmission in an electricity market with renewable sources of electricity.

8.3 Cost Recovery

As outlined previously in Chapter 5, transmission constraints lead to differences in nodal prices between nodes. The summation of the difference across the year leads to a surplus or ‘network revenue’. [73] expresses the difference as follows:

$$NR = \sum_{h=1}^{8760} \sum_{l(ni,nf)} \left(\lambda_{h,nf}.FLE_{h,l(ni,nf)} - \lambda_{ni}.FLE_{h,l(ni,nf)} \right) \tag{8.2}$$

The question naturally arises then whether this network revenue is sufficient to cover the cost of transmission within the system. [73] show that in theory, and under the correct circumstances, the network revenue is sufficient when the level of transmission investment is optimal. However, realities of the power system dictate that these findings do not hold true when real-world considerations are taken into account. These real-world considerations include lumpiness in investments, reliability constraints, and economies of scale.

These findings have been confirmed with the Expan model as shown in Table 8.1. This confirmation additionally serves as a check that the Expan model is behaving similarly to other models in the literature. The scenario considered in Table 8.1 consists of a case where a 5% PV renewable portfolio standard is in place for the system. This translates into a case where 12.16 GW of photovoltaic capacity is developed in the model, the majority of which is located in the western nodes with the best quality resources. This scenario will serve as an illustrative example throughout this chapter.

Table 8.1: Transmission Cost Recovery Comparison for a Chosen Case

	Continuous Case, no existing transmission	Discrete Case, existing system included
Total Network Revenue	M\$290.538	M\$266.127
Total Transmission Fixed Costs	M\$290.538	M\$708.034
Percent Recovery	100%	37.57%

The differences between the two runs represented in Table 8.1 are as follows: the right hand side case contains discrete transmission investments in 1500MW capacity lines, a representation of the underlying ERCOT transmission system, a transmission security reliability constraint, and transmission losses. The left hand side on the other hand contains all continuous variables, no existing transmission lines, no transmission security factor, and no transmission losses. The underlying system is important as the theory dictates that 'optimal' investment recovers costs - and not all the lines of the old system are considered optimal by the model. This is not unexpected as the existing transmission system was developed in the presence of many historical 'real world constraints' which the model does not include.

At this illustrative stage (from the right hand column of Table 8.1), it can be seen that in a real power system, there will be a need for a complementary charge. Note that this is the case for a power system that includes nodal pricing, and thus has locational signals. For those systems that do not have a nodal pricing system but a system-wide electricity price, then the need for a complementary charge is all the more prevalent. The allocation of the required complementary charge is discussed in the next section.

8.4 Cost Allocation

Having shown the need for an additional transmission charge, the decision must be made of where to allocate that charge. If the onset of a new generator onto a power system incurs transmission costs for the system it may be tempting to place the responsibility for these costs on the generator. Such an approach however does not recognise the reality that more entities than this generator will use and benefit from this transmission upgrade. Consumers have access to an additional competitive electricity supplier in the market, and power produced from other generators will also be able to be transferred across the upgraded transmission corridor.

It should also be noted that new demand is a major driver for transmission investment in a power system too.

8.4.1 Principles of Allocation

Before proceeding in the discussion of cost allocation of transmission charges, some principles are set out based on economic and electrical engineering principles.[3]

- Assuming that a transmission investment is only made when the benefits of doing so outweigh the costs, it is economically sound to allocate the costs of the investment to those who benefit. This 'Allocation to Beneficiaries' approach implies that circumstances exist where both generators and consumers should pay. Equivalently, costs could be allocated to users responsible for the investment.
- Transmission charges should be independent of commercial transactions
- Transmission charges can provide locational signals to ensure efficient expansion of a power system. In order to provide this signal, transmission charges by location should be known *ex-ante* to potential investors.

These principles underlie the development of the remainder of this chapter. Note that for simple, well-meshed networks, a 'Postage Stamp' method may be most appropriate due to regulatory advantages of simplicity. This method involves the application of a simple flat charge to all those using the system, independent of where they are located or how much they use the system. However as almost all power systems have some distribution of potential renewable electricity sources, it is questionable whether such a cost allocation methodology will be adequately robust in any system in the coming decades.

8.4.2 Implementation Difficulties

Applying the 'Allocation to Beneficiaries' approach is difficult in practice, for two primary reasons. First of all, to determine the benefits requires comparing two counterfactual worlds - a world with the transmission upgrade and a world without. Determining the world without the line is extremely difficult as it is likely that something else would have been

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[3] These principles derive largely from those laid out by [94].

done as opposed to 'do nothing'. This particular problem does not apply for new lines. For new lines however, the problem shifts to reasonably estimating future counterfactual worlds with or without the line that is in question. Secondly, determining the benefits also requires extensive knowledge of generators' costs, information that could be considered proprietary in a free market context.

8.4.3 Proxies based on Network Utilisation

Considering the difficulty of estimating benefits with the allocation to beneficiaries approach, a 'next-best' approach is to use some proxy to determine beneficiaries. One such proxy is to assume that the usage of the network by an agent is a reasonable representation of the benefit the agent receives from it. The physical behaviour of electrical energy is such however that there is no method to 'track' flows from a generator to a load, and thus perfectly measure network usage. The results of a calculation of determining network usage will thus depend on the method adopted. The following are some possible methodologies:[4]

Contract Path

With this approach, the path taken by electrical energy between the point of injection into, and point of withdrawal from, the system is determined by agreement between the buyer, seller, and any intermediate third parties. Since physical laws of electric power flow are not explicitly included, the corresponding path is somewhat arbitrary, along with the associated allocation. In addition, such an approach can lead to 'pancaking' of costs when numerous third party areas have to be crossed.

MW-Mile

This method attempts to measure network usage by representing both the power transferred and the length of line over which it is transferred. A base load flow case is chosen and the product of power flow on, and the length of, each line is summed over the power system. This process is repeated for another load flow case with a transaction removed. This difference then represents the network usage of that particular transaction and network costs are allocated accordingly to that transaction.

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[4] This section has benefitted from the material provided in [95].

This allocation to individual transactions however violates one of the principles of cost allocation outlined above - transmission charges should be independent of commercial transactions.

Marginal Participations

The marginal participations method determines network use by considering how the flows in a system change when the generation or consumption by a network user increases by 1MW. A major problem with this method however is that Kirchoff's Laws require that if generation (or demand) increases by 1 MW in the system, demand (or generation) must also increase by 1 MW net losses elsewhere. This choice of slack bus will then greatly influence the result of implementing the MP algorithm, adding a sense of arbitrariness to the result.

Aumann-Shapley

The extension of the Aumann-Shapley method of cost allocation for transmission services is described in detail in [96]. This method (grounded in game theory) operates as follows. A generator is given the choice of selecting its matching loads in such a way as to minimise its transmission tariffs. Then the next generator repeats the process, followed by the next generator and the next generator until the final generator by definition will have to accept the remaining loads. Obviously the entrance order of the generators influences the result. To overcome this it has been shown that repeating this process for every possible entrance order of generator and taking the average over all combinations will produce the efficient allocation of costs.

Average Participations

The average participations method uses actual, measured flows and operates on the simple principle that the responsibility of the flow entering a node, $f_{in,k}$, for a flow exiting the node, $f_{out,i}$ is in proportion to the total amount of flows exiting the node, $\sum_i f_{out,i}$, as displayed in equation (8.3) below[5]. While this is an assumption that cannot be proved physically, it is simple to understand, is based on actual measured data, and requires no further assumptions, such as the choice of a slack bus, to be included in the method.

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[5] Equation 8.3 follows the form presented in [97].

$$C(f_{in,k}, f_{out,i}) = \frac{f_{in,k}}{\sum_{i=1}^{n} f_{out,i}} . f_{out,i} \tag{8.3}$$

[94] propose a modified version of the AP method to account for aspects that the 'traditional' Average Participations method does capture - for example, recognition of the contribution that a generator at an importing node would make to the transmission system. In this formulation, the unit contribution of generation at node nd, C_{nd}, is presented as follows:

$$C_{nd} = F_{nd} C_{nd}^{G} - (1 - F_{nd}) C_{nd}^{D} \tag{8.4}$$

Where C_{nd}^{G} is the unit contribution of generation at node nd to the network while C_{nd}^{D} is the unit contribution of demand at node nd to the network, with both determined from the 'traditional' Average Participations algorithm. F_{nd} represents a weighting factor and is defined as the total power exiting a node versus the total power entering and exiting the node:

$$F_{nd} = \frac{\sum_{h,nf} FLE_{h,l(nd,nf)}}{\sum_{h,ni} FLE_{h,l(ni,nd)} + \sum_{h,nf} FLE_{h,l(nd,nf)}} \tag{8.5}$$

In a similar fashion, the unit contribution of demand at each node can also be calculated.

8.5 Implications for Solar Power in Market Environment

8.5.1 Objective Function of Photovoltaic Investors

Using the terminology of Chapter 5, and noting that the variable cost of solar power generation is zero, the objective function of a new solar generator gs at a node nd is as follows:

$$max\, U_{gs} = \left(\sum_{h=1}^{8760} \lambda_{h,nd} . PTP_{h,gs} \right) - PTI_{gs} . FC_{gs} \tag{8.6}$$

Similarly, if there are policy mechanisms to support photovoltaic generation in place, the objective function of the investor under a premium feed-in-tariff scheme and a RPS scheme are as follows:

$$max\, U_{gs} = \left(\sum_{h=1}^{8760} (\lambda_{h,nd} + FIT) . PTP_{h,gs} \right) - PTI_{gs} . FC_{gs} \tag{8.7}$$

$$max\, U_{gs} = \left(\sum_{h=1}^{8760} (\lambda_{h,nd} + \tau).PTP_{h,gs} \right) - PTI_{gs}.FC_{gs} \tag{8.8}$$

Where FIT is the premium feed-in-tariff paid to investors and τ is the dual variable of the RPS constraint, representing the value of a 'renewable energy credit'.

8.5.2 Margin on Solar Investment

Applying the relevant objective functions above to the outputs of the various runs of the Expan model as presented earlier in this document consistently returns an objective value of zero. For further support of this finding, the solar generator's profit from our illustrative example of earlier in this chapter (a run with a 5% RPS in place along discrete modelling of transmission investment) was inspected. The profit, as described by equation (8.8), was \$0. Across these runs, λ_{nd}, the nodal price, is providing the appropriate locational signals to the generators.

This complies with the theory that in an ideal world, with perfect competition, perfect information, and no temporal discontinuities - generation investment will be made to such a degree that generators will make a net profit of zero (note return on capital will be included within the fixed cost). A further justification of this result can be obtained by inspecting the above equations and dividing each by PTI_{gs} - taking this action returns the equations (5.24), (5.36) and (5.38), directly derived from the model optimality conditions.

8.5.3 Effect of Transmission Charge on Generators

Under 'Perfect' Conditions

Having shown that the generator revenues in equations (8.6), (8.7) and (8.8) are equal to \$0 at the optimum solution of the Expan model, it is clear that any additional term in the generator's objective function will shift the equilibria and lead to a different outcome. Thus if any transmission charge is placed on the generator, the equilibrium point will be moved and a different level of investment will be undertaken. This would be equally true should the investor include the transmission costs within the fixed costs of the generator capacity.

This finding implies that when transmission charges are assigned to generators, the centralised model and the market model produce different optimal results. This would imply that all transmission charges should be assigned to demand for the market to produce the social optimum. There are numerous qualifications that should be mentioned however:

- This finding assumes that in the market model there is a perfect transmission planner building the optimal network that the market will construct generation capacity around. This would require the transmission planner to have perfect information of the costs and options of the different agents in the market. Market agents would also be required to have full information of the transmission to be constructed so that they can accurately estimate the energy prices they will receive to offset their investment.
- It also assumes no temporal distortions - in reality transmission planning, investment and development takes significantly longer than the development of a wind or solar plant.
- In the framework of this model, homogeneity is assumed across generators of each technology. In the real world, such differentiation would lead to elements of competitive advantage where a margin will exist and thus transmission charges would not distort the market behaviour.

To further this discussion, we now consider two examples where transmission charges have the potential to align investor's decisions closer to the system optimum. The first example consists of a case where imperfect conditions leads to a system with a transmission infrastructure not in line with the system optimum for the associated generation capacity. The second example consists of a case where renewable generators receive a margin deriving from the design of a renewable energy support scheme.

Example 1: Under Imperfect (Realistic) Generation and Transmission Conditions

For this example we will again refer to the 5% RPS case mentioned throughout this chapter. Assume for this example that imperfect information has resulted in 1 transmission line as opposed to the system optimum 2 being constructed in the 61-63 corridor. At this point in the dynamic evolution of a power system, the construction of that 1 extra line will yield benefits (or losses) to generators and consumers. This example will then consider how the cost allocation methodologies previously outlined can be applied to this particular situation.

Allocation to Beneficiaries

As per Section 8.4.1, 'Allocation to Beneficiaries' is the economic method of choice for cost allocation, and is thus applied first here. To assess the beneficiaries of the addition of the line, the model outputs for the 5% RPS case were compared to the model outputs for the same case but with the transmission system missing a line between nodes 61 and 63. The benefit for each generator g at node nd, is defined as $\Delta\left(\sum_h PTP_{h,g}.\lambda_{h,nd}\right)$, while the benefit for consumers at each node, nd, is defined as -$\Delta\left(\sum_h DMD_{h,nd}.\lambda_{h,nd}\right)$, where Δ represents the difference between the optimum and sub-optimum cases. It should be noted that a full real-world application of the 'Allocation to Beneficiaries' method would involve considering the benefits across the whole life of the line, a more difficult thing to do.

Tables 8.2 and 8.3 portray the winners and losers of an additional line between nodes 61 and 63. In addition, Table 8.4 aggregates the benefits by node. Considering the annualised cost of a line on the corridor to be 39.5 million dollars, it is clear that the benefits of constructing the line far outweigh the costs of doing so. Secondly what is striking is the distribution of the costs and benefits of a single line, with costs and benefits shared amongst many users. Referring to Table 8.2 it is clear that wind and solar generation at the exporting node 61, and demand at node 63 each would be allocated cumulatively 47% of the cost of the line. This implies that 53% would then be allocated widely to users throughout the system.

The largest losers are generation at node 63 in addition to consumers at nodes 65 and 64. This latter finding may be non-obvious but the reasons stem from the nature of electric energy flow. With the newly installed line, increasing amounts of cheaper wind and solar power flow to the greater demand at node 63. This entails that nodes 64 and 65 have less access to these cheaper sources of electricity, leading to increased conventional generation (particularly coal) at these nodes. This thus leads to an increase in electricity prices and thus consumer cost at those nodes, producing a negative consumer benefit with the construction of the line.

Average Participations

Now assuming that the situation was such that allocation to beneficiaries was not practically implementable for this example situation, the Average Participations method could be applied to estimate network usage and thus the cost allocation of the line. An algorithm was developed to implement the method for the outputs of the Expan model, and a copy of the code is included in Appendix C. The application of the algorithm required review and

Table 8.2: Beneficiaries of Additional Line Installation Between Nodes 61 and 63

Network User	$M\$$	Percentage
dmd-63	345	24%
solar-61	168	12%
wind-61	157	11%
coal-64	143	10%
coal-65	122	9%
solar-62	102	7%
gas-64	68	5%
gas-62	66	5%
coal-67	60	4%
coal-60	40	3%
nuclear-65	39	3%
wind-62	37	3%
wind-60	21	2%
OGS-65	13	1%
gas-65	13	1%
solar-60	12	1%
solar-64	12	1%
OGS-67	5	0%
OGS-62	1	0%
Totals	*1425*	*100%*

Table 8.3: Losers from Additional Line Installation Between Nodes 61 and 63

Network User	$M\$$
dmd-65	-147
dmd-64	-129
dmd-67	-89
dmd-61	-81
dmd-62	-46
dmd-60	-21
gas-63	-216
coal-63	-134
OGS-63	-112
gas-60	-43
nuclear-63	-39
gas-67	-33
OGS-60	-10
gas-61	-6
OGS-64	0
Total Cost	*1107*

Table 8.4: Allocation by Node of Generator's Portion of (New) 61-63 Line Cost under Allocation to Beneficiaries Method

	L(61,63)
G-60	2.13%
G-61	32.21%
G-62	20.95%
G-64	22.50%
G-65	18.87%
G-67	3.34%

Table 8.5: Extent of Generator's Use of Transmission Corridor 61-63 by AP method

	L(61,63)
Gen-60	0.15%
Gen-61	75.83%
Gen-62	17.40%
Gen-63	0.01%
Gen-64	5.16%
Gen-65	1.44%
Gen-67	0.00%

interpretation of the relevant literature, along with adaption in order to be applicable to the output formats of the Expan model.

To determine the distribution of use of the transmission corridor between nodes 61 and 63 (and thus the proxy beneficiaries), the method was applied to the case post-expansion of the capacity of the corridor.

To illustrate the operation of the AP method, Figures 8-1, 8-2, and 8-3 are presented. Figure 8-1 displays a snapshot of the system flows, generation and demand at hour 2869 of the year. Figure 8-2 displays the application of the AP algorithm to generation at Node 61 while Figure 8-3 displays the application of the algorithm to demand at Node 63. Hour 2869 has been chosen for this illustration as it is the hour with the greatest solar intensity at node 61 in this dataset.

Table 8.5 displays the results of the weighted average of the contribution to usage of L(61,64) of the generation entities across the year, while Table 8.6 displays the same results for load entities. Taking these contributions and applying the modified version of the Average Participations method (as expressed by equation (8.4)) produces Table 8.7.

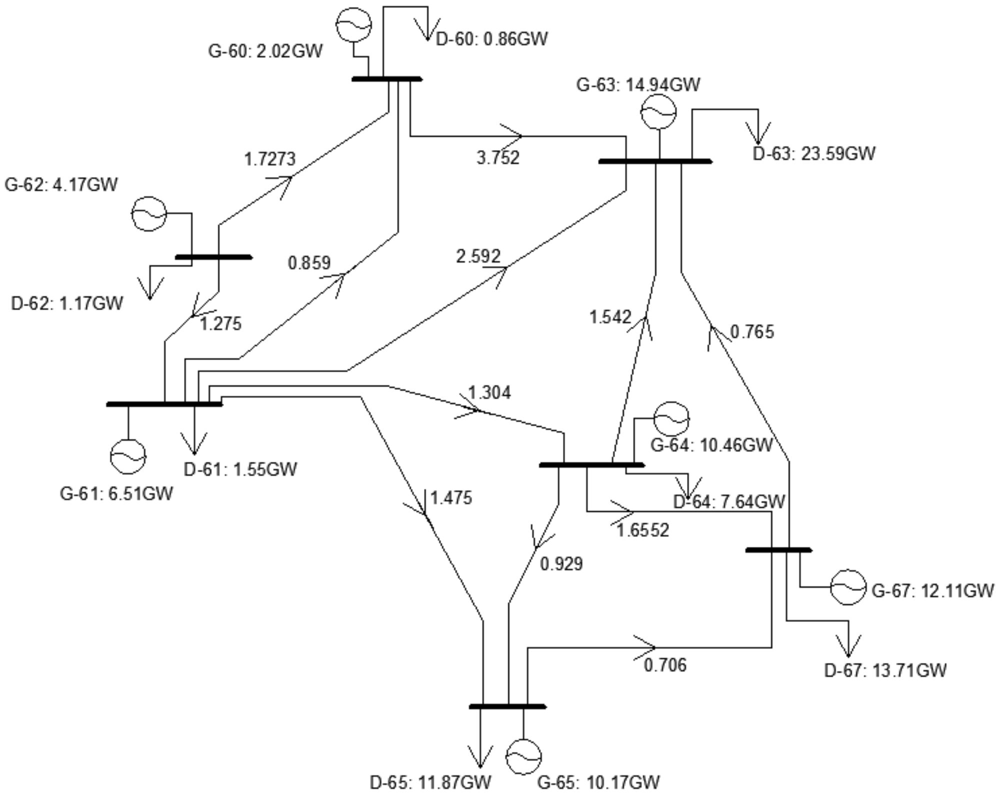

Figure 8-1: Generation, Demand, and Flows at Sample Hour 2869

Table 8.6: Extent of Demand's Use of Transmission Corridor 61-63 by AP method

	L(61,63)
D-60	0.00%
D-61	0.01%
D-62	0.00%
D-63	99.64%
D-64	0.00%
D-65	0.00%
D-67	0.34%

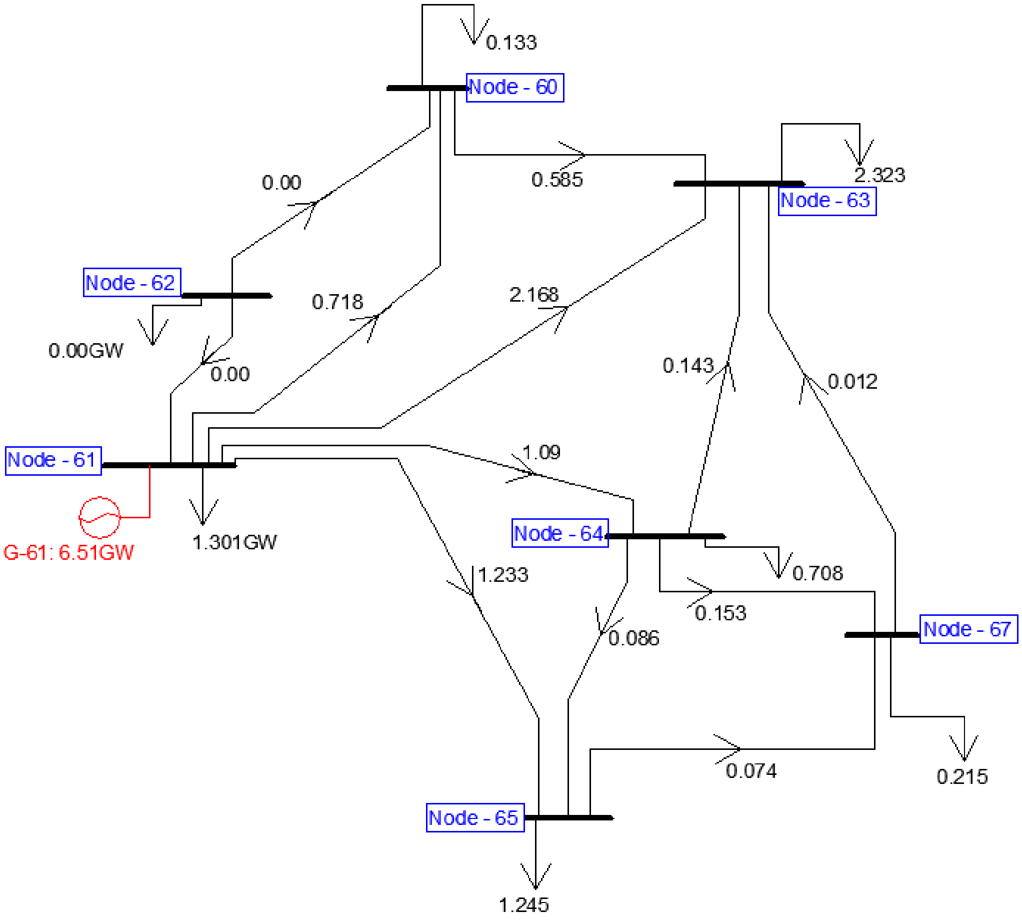

Figure 8-2: Results of Average Participations Methodology Applied to Generation at Node 61 (in hour 2869)

Table 8.7: Contribution Per Unit of Generation (at each node) to Power Flow on Line 61-63 by Modified AP Method

	L(61,63)
G-60	0.0014
G-61	0.6025
G-62	0.1739
G-63	-0.9782
G-64	0.0513
G-65	0.0088
G-67	-0.0034

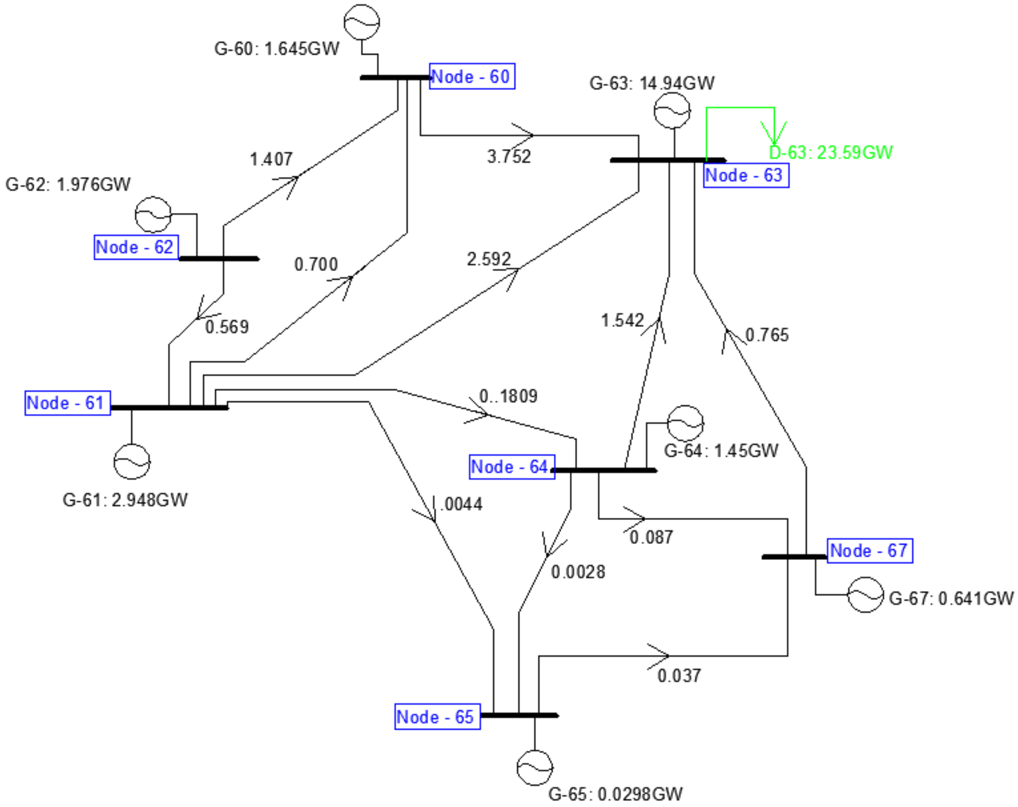

Figure 8-3: Results of Average Participations Methodology Applied to Demand at Node 63 (in hour 2869)

Table 8.8: Allocation Amongst Contributing Generation of Table 8.7

	L(61,63)
G-60	0.17%
G-61	71.90%
G-62	20.76%
G-64	6.12%
G-65	1.05%

Table 8.9: Comparison of AP and AB Allocation of Generator's Portion of Costs

	AB	AP
G-60	2.13%	0.17%
G-61	32.21%	71.90%
G-62	20.95%	20.76%
G-64	22.50%	6.12%
G-65	18.87%	1.05%
G-67	3.34%	0.00%

Comparison of Average Participations (AP) and Allocation to Beneficiaries (AB) results

Comparing the AB and AP determination of the contribution to be paid by generators produces Table 8.9. The notable difference is the greater allocation AP places on the (solar and wind) generation of node 61. This is accurately based on the flows across the 8760 hours of the considered year, when in many hours, zero variable cost generation at node 61 exports to the high-demand node of node 63.

This comparison yields two major points about the use of a 'beneficiary proxy' such as AP as opposed to calculating the actual beneficiaries under the AB method. AP simply estimates the usage by network entities of a particular network facility. It does not provide an estimation of which network entities benefit or lose from the same network facility relative to a counterfactual world without the facility. Secondly, AP will allocate amongst generators and amongst demand but provide no indication of how much to allocate to each on aggregate.

AP cannot capture this class of effect and will thus remain a 'second best' solution to Allocation to Beneficiaries (AB). However, if network usage is to be used as a proxy to estimate the beneficiaries, the results AP provides are reasonable and certainly represent a significant improvement upon methods previously outlined such as 'MW-mile' and 'Contract Path'.

While transmission cost allocation is relevant to each type of generating technology, for reasons previously outlined, transmission investment is necessary for deployment of solar power beyond small-scale levels. Thus how the cost is allocated is relevant to the efficient deployment. This example represents the situation of imperfect conditions on a dynamically evolving power system where a transmission charge levelled on a solar generator can lead to generator and system-wide benefits.

In the long-term for a ‘perfect’ system, we have shown how the locational signals provided by nodal prices at equilibrium should be adequate for optimal investment and transmission charges for generators would have a distorting influence. However, in the dynamic evolution of a real power system between optima, it has been shown here that a window of transmission charges for generators would be beneficial for both the generators and the system.

The zero variable cost economic characteristic of renewable generators, along with the physical laws of power flow however, lead to some non-intuitive findings in the application of estimating the benefits. In particular, in this example, conventional generators benefitted from a line to which they were not directly connected as the wind and solar power was diverted to a different node with the construction of the line.

We next consider the case where a solar power generator derives an incentive from support design to locate in a non-system optimum fashion and thus transmission charges have a potential role in providing appropriate locational signals.

Example 2: Margin Deriving from Mechanism Design

The feed-in-tariff described in equation (5.38) and (8.7) is but one type of feed-in-tariff. Here we consider the case of a flat feed-in-tariff, popular for the certainty and stability it provides investors, and thus its facilitation in the financing of projects. Under such a support scheme, the objective function of the photovoltaic generator is as follows:

$$max\, U_{gs} = \left(\sum_{h=1}^{8760} FIT.PTP_{h,gs} \right) - PTI_{gs}.FC_{gs} \tag{8.9}$$

Noting that the $PTP_{h,trs} = PTI_{trs}.PF_{h,trs}$ in the hours when solar generators are fully dispatched which to a certain level of penetration will always be the case, and considering the marginal unit (i.e. $PTI_{trs} = 1$) the equation above can be rewritten as follows:

$$max\, U_{gs} = FIT \left(\sum_{h=1}^{8760} PF_{h,Gs} \right) - FC_{gs} \tag{8.10}$$

In order to gain more insight into the implications of this equation, the 5% RPS run that has served as an example throughout this chapter is returned to. The dual variable of the associated constraint was 101\$/MWh. While it is possible to directly relate this

Table 8.10: Profit Per Unit of PV Capacity at Each Node Under Flat PV Feed-in-Tariff of \$151.2/MWh

Generator	[1] $\sum_{h=1}^{8760} PF_{h,gs}$	[2] FIT $M\$/GWh$	[3] FC_{gs} $M\$$	[4]=[1].[2]-[3] U_{gs} $M\$$
Solar-60	1843	0.1512	269.94	8.72
Solar-61	1967	0.1512	269.94	27.47
Solar-62	1930	0.1512	269.94	21.88
Solar-63	1692	0.1512	269.94	-14.11
Solar-64	1727	0.1512	269.94	-8.82
Solar-65	1721	0.1512	269.94	-9.72
Solar-67	1733	0.1512	269.94	-7.91

figure with a premium feed-in-tariff, it is not possible to directly compare with the flat feed-in-tariff. For the purposes of this illustrative example, a reasonable representation of an analogous flat feed-in-tariff is the dual variable of the RPS constraint plus the expected nodal price across the system. This produces a feed-in-tariff of $\$101/MWh + \$50.197/MWh = \$151.197/MWh$. Ignoring the magnitude and focussing on the patterns, the application of this flat FIT to equation (8.10) produces Table 8.10, showing the profit (or loss) for PV generation at each node.

Table 8.10 indicates that a flat feed-in-tariff scheme will create margins for solar generators at nodes 60, 61, 62, incentivising investment at those nodes. This is in contrast with the results of the 'optimal' model with the analogous RPS scheme - where investment occurs at nodes 60, 61, 62 and 64 with a net profit of 0 for each solar generation at these nodes.

In addition to not producing the optimal distribution of PV investment, the flat feed-in-tariff and associated lack of locational signal creates an incentive for overinvestment. Within this framework, the only limits on the amount of investment at the western nodes are a) a cap on the total amount to be paid out under the feed-in-tariff program and b) the breakdown of the relationship of $PTP_{h,gs} = PF_{h,gs}.PTI_{gs}$ in certain hours throughout the year as curtailment increasingly occurs due to transmission constraints or due to total supply of solar electricity outstripping total system demand.

One potential way to recover excessive margins and align incentives in accordance with the social optimum is the imposition of well-designed transmission charges.

Under the flat feed-in-tariff scheme, the generator's objective function is then modified as follows:

$$max\, U_{gs} = FIT\left(\sum_{h=1}^{8760} PF_{h,gs}\right) - FC_{gs} - TC_{gs} \tag{8.11}$$

Where TC_{gs} is the imposition of an annual transmission charge on generator gs.

Considering again the example of Table 8.10, a transmission charge could be levied on new generation at nodes 60, 61, and 62, while a negative transmission charge could be put in place for new solar generation at node 64, in order to acknowledge this generation's contribution to the overall system, thus aligning the flat feed-in-tariff world with that of the centralised optimum world. The assumption remains however that the transmission system is centrally planned in this scenario.

Insights about how this transmission charge could be calculated can be derived from Example 1. Allocation to Beneficiaries would be the ideal method as it could reflect the benefit solar power generators receive from the flat feed-in-tariff and thus allocate the cost of any required network improvements accordingly. Additionally, if network usage was to be a proxy for beneficiaries, we have seen how AP could be applied, with its relative strengths compared to other network usage methods and its weakness relative to the difficult-to-implement Allocation to Beneficiaries method.

Appropriately designed, and provided ex-ante, a transmission charge could prevent over-investment at remote nodes. Note this does not mean that generators pay for all transmission to the remote node but that they are charged in such a fashion that investment in transmission will not be required beyond the system optimal (and that the solar power being promoted by public policy is deployed in an efficient manner). It appears that this will be a system-specific issue, depending on the nature of the underlying power system and the distribution of the solar resource.

It is apparent from this discussion that in the event that support schemes for renewable generators do not include a locational signal, appropriately designed transmission charges potentially have an important role in boosting the overall efficiency of the support scheme in delivering its stated goals. The simple example of this chapter highlights that designing transmission charging schemes in isolation from renewable support schemes can lead to inefficient outcomes in a world with large quantities of renewable energy installed. These issues are magnified in importance as increasing levels of renewables enter the grid.

It should be acknowledged finally that flat feed-in-tariff schemes as implemented on occasion implicitly have a locational signal - examples include the cases where there are tiered rates depending on the location (i.e. a different rate for rooftop photovoltaics). This highlights a potential differentiating factor between wind and solar power in this discussion. With photovoltaics, (more so than with wind energy) there is the option of a distributed location of plants should that be the system optimal thing to do.

8.6 Chapter Summary

- A brief discussion has taken place as to why transmission is relevant to solar power deployment.
- Following the somewhat simple treatment of transmission power capacity in the Expan model earlier in the thesis, what actually constitutes the ability of a transmission line to transport electrical energy is discussed.
- Why there is a need for a complimentary transmission charge to be paid by demand or generation was outlined
- Cost allocation methods of transmission charges were discussed.
- It was found that under the framework of the simple Expan model, the allocation of any transmission charge to a generator will distort their objective function, and thus create a new equilibrium from that of the centralised optimum. This is based on assumptions difficult to translate to real world - particularly how the appropriate transmission plan is designed.
- Nodal prices are shown to provide the appropriate (and adequate) locational signals to the generators in the model framework. This assumes that entities are able to adequately estimate future nodal prices. While this assumption may not be realistic, this point at least highlights that the pool single market price approach adopted in many European systems has many disadvantages for the efficient deployment of renewable generation.
- An output case of the Expan model was studied to investigate a situation where, due to (realistic) imperfections, a system is not ‘optimal’ but moving toward the ‘static’

optimal solution. Transmission charges allocated to generators in such a case allow the system to move toward the system optimal. The different results provided by the 'Allocation to Beneficiaries' and 'Average Participations' cost allocation methods were compared and discussed. How the beneficiaries of a transmission line can range significantly beyond the generators and consumers at either end of the line was illustrated by this example.

- A second example has been constructed that illustrates how renewable support schemes that allow a renewable generator not 'see' any locational signal have the potential to produce inefficient outcomes. Appropriate transmission charging in these circumstances has the potential to align agent behaviour closer to the desired social optimum. Alternatively, renewable support schemes that provide a support on top of the system nodal price are shown to allow the appropriate locational signal to be maintained.

It is apparent from the work of the later sections of this chapter just how complex the issue of transmission of electrical energy produced by renewable energy sources is. This is not complexity in terms of the technical challenge of building and operating additional transmission infrastructure but complexity in determining a) to what extent infrastructure should be built and b) who bears the cost. This latter economic and regulatory complexity, in turn stems from technical issues - the distribution of the wind and solar resource, the distribution of the production profile of each generator, and the physical laws of electric power flow. Important factors in determining (a) were illustrated in Section 5.4 earlier in the thesis, while this chapter has focussed on (b), from which a number of principles can be returned to:

- The solution for cost allocation will need to be adapted for each particular situation. Consideration is required of the underlying generation and transmission infrastructure, future expansion plans, and renewable power support schemes that are in place (which themselves could require adaption).

- Considering these factors, in a dynamic, imperfect system, costs of a particular investment should be allocated to the beneficiaries of a particular investment.

- If it is not feasible to determine the beneficiaries, a network usage proxy could be applied such as the Average Participations method.

- Finally, it should be remembered that such processes create transaction costs and that there is always benefit to simplicity in regulation. Should future systems stabilise around an equilibrium point, a return to postage stamp methods of transmission cost allocation may be appropriate. However, to efficiently adapt power systems over the next number of decades in line with stated policy goals worldwide, it is clear that these more complex methods of regulation are necessary to address the complex issues outlined in this chapter.

Chapter 9

Conclusions, Findings and Recommendations

In order to gain an understanding of the interrelated technical, economic and regulatory implications of the large-scale deployment of solar power, the following tasks were undertaken and completed in the preparation of this thesis:

Tasks Completed

- How power systems are designed and operated, how electricity from solar energy is produced, and how these systems interact have been analysed from a technical and economic perspective.
- A linear cost minimisation model, adapted from the literature, and incorporating generation and transmission expansion and operation variables, was designed, developed and applied. The model, entitled Expan, was applied to a simplified version of the ERCOT (Texas) power system for a range of scenarios where large quantities of photovoltaics or concentrating solar power may be deployed - because of decreasing cost of technology, application of solar-specific Renewable Portfolio Standards, or existence of a carbon price.
- The formulation of the Expan model was analytically studied in order to a) understand the tradeoffs that are behind the model results and b) gain insight into the underlying components of the marginal benefit of a solar generator in a network system. The

formulation also included concentrating solar power with thermal storage.

- The NREL ReEDS model was employed to investigate further the findings of the Expan model and as a means to compare different expansion model formulations.

- A particular focus was placed on an important aspect of solar power deployment - the adaption of transmission networks. Using outputs from the Expan model, the impact of transmission charges on solar generators in a market environment, and as beneficiaries of renewable support subsidies, was analysed. As part of this investigation, a method (Allocation to Beneficiaries) to estimate the beneficiaries of a transmission facility was implemented. In addition, an algorithm to approximate network usage (based on a modified version of the Average Participations method), was interpreted, adapted, developed and applied.

Findings

From Solar Energy Characterisation:

- Application of solar radiation data to a duration curve framework highlights the variability of the production of solar photovoltaic plants (Figure 9-1). Without undertaking any further analysis, this figure shows the importance of other technologies, for example energy storage or flexible conventional generation or both, as enabling technologies for power systems with large quantities of solar power capacity installed. This underlies much of the following discussion.

From Analytical Development of Expan Model:

- Resulting from the analytical development undertaken, an expression was developed to consider how network effects influence the 'system marginal benefit' of a wind or PV generator (equation (9.1) - a repeat of equation (5.30)). One noteworthy feature is the influence of the patterns of production of the solar generator, and the influence of the covariance of these patterns with system dual variables.

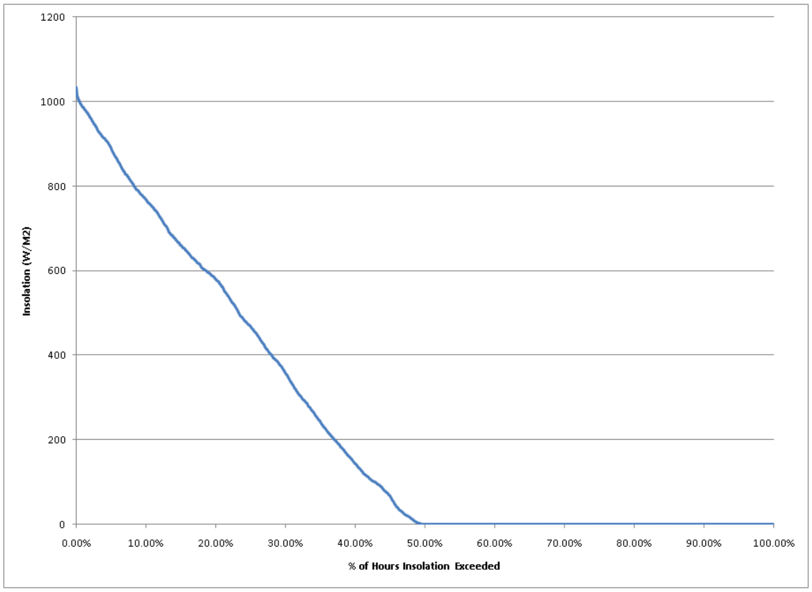

Figure 9-1: Global Insolation Duration Curve for McCamey, Texas
Hourly data from 1998. Figure repeated from Section 2.2.4.

$$\begin{aligned} MV_{gr} &= H.E(\lambda_{nd}).CF_{gr} + H.cov(\lambda_{nd}, PF_{gr}) \\ &- FCt_{l(ni,nd)}.CF_{gr} - H.cov(\beta^1_{l(ni,nd)}, PF_{gr}) \\ &+ 2H.E(\beta^2_{l(ni,nd)}).CF_{gr} + H.cov(\beta^2_{l(ni,nd)}, PF_{gr}) \\ &+ H.E(\alpha_{l(ni,nd)})CF_{gr} + H.cov(\alpha_{l(ni,nd)}, PF_{gr}) \end{aligned} \tag{9.1}$$

- The expression shows that, at a node behind a transmission constraint, the marginal value of PV capacity will decrease relative to the case where no transmission constraints exist. This reduction will lead to a lower quantity of installed PV capacity at that node, again relative to the case where no transmission constraints exist. The cost of relieving this constraint, i.e. the cost of transmission, thus is the underlying factor. However, the expression shows that the extent to which it reduces the marginal value depends on the relative patterns involved.

- The framework also highlights how the marginal value (and potentially the corresponding installed capacity) of a PV generator can increase on the demand side of the transmission constraint, depending on the relevant covariance terms.

These effects contrast from conventional generation as performance of a conventional generator is independent from location in the context of this framework.

- Equation (9.1) highlights how technologies that can shift the relative covariance terms can influence and increase the system value of PV power.
- The framework allows for the interactions of photovoltaics and other technologies on the power system to be analysed. For example, numerical application to the ERCOT power system showed that photovoltaics can increase the value of wind energy. Non-generalisable results indicated an opposite effect for wind power's impact on photovoltaics (Section 6.2.3).
- The development of the framework highlighted how the absolute implications of solar power deployment are system-specific, as the pattern of production across space and time affects outcomes.

From Numerical Analysis:

- Applying the developed Expan model to the ERCOT system for a decreasing cost of photovoltaics shows a decline in baseload generating capacity (Section 6.5), and at a very high level of photovoltaic deployment - an increase in gas capacity (Figure 9-2).

  Note there is a difference between long-term and short-term effects. In the short term (and at lower PV penetration), PV deployment leads to a decrease in gas usage and associated operating costs, as gas is usually the generator on the margin as the PV power is produced. In the long term, as the system adapts to PV deployment, it is optimal to have less baseload capacity as there are fewer hours of the year where it can run at full capacity and recover its costs.
- CSP deployment results returned a similar finding for baseload capacity as PV but a dissimilar finding for gas capacity. The ability of CSP, as presented in this document, to store energy entailed that less backup generation was required for when the sun does not shine in the CSP deployment scenarios (Section 6.4.1).
- It is clear from the various models that the technology displaced by solar power deployment is the 'base case' technology. What that avoided investment will be in a world without photovoltaics is difficult to predict, and depends on many uncertain

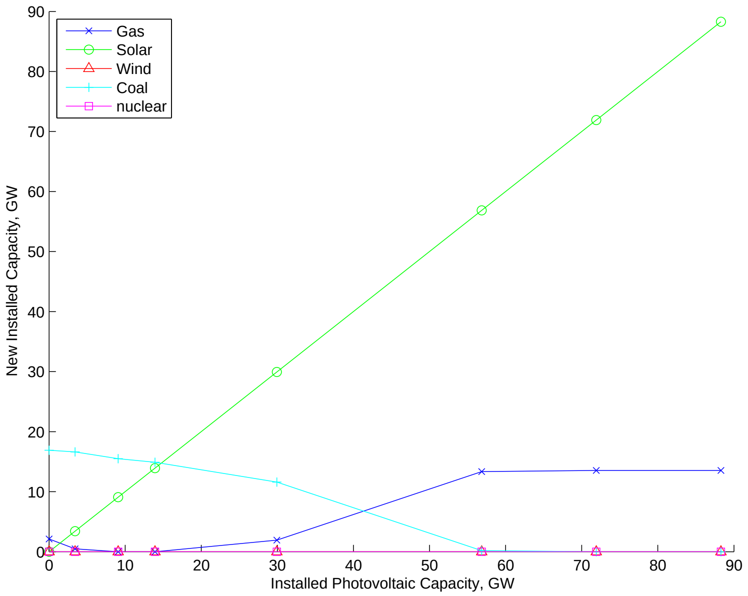

Figure 9-2: New Generation Capacity versus PV Capacity (cost reduction case)
Repeated from Section 6.3.1

factors - with a sample including; carbon legislation, extent of demand participation and smart grid development. This is a relevant consideration - as what technologies solar power displaces determines the carbon reduction benefits provided by the solar power.

- The method of PV deployment was found to lead to changes in the distribution of the installed PV capacity, with implications for associated transmission requirements (Figure 9-3). Particularly, RPS support or premium feed-in-tariff support for PV led to concentration of capacity in the high-quality areas while cost reductions led to a greater distribution in where the PV capacity was installed (Section 6.3.1). This finding was not repeated for the CSP deployment scenarios, where plants generally need to be constructed in the highest quality solar resource areas.

- The concentrating solar power results from the Expan model highlight the benefits of energy storage (and associated higher capacity factor). A fundamental limit to photovoltaics deployment is when production is greater than demand and the resulting surplus energy has zero economic value. This is in contrast to the potential ability of CSP to shift when it produces - and thus is less subject to being curtailed. Figures 9-4 and 9-5 display the difference production profiles between the technologies at

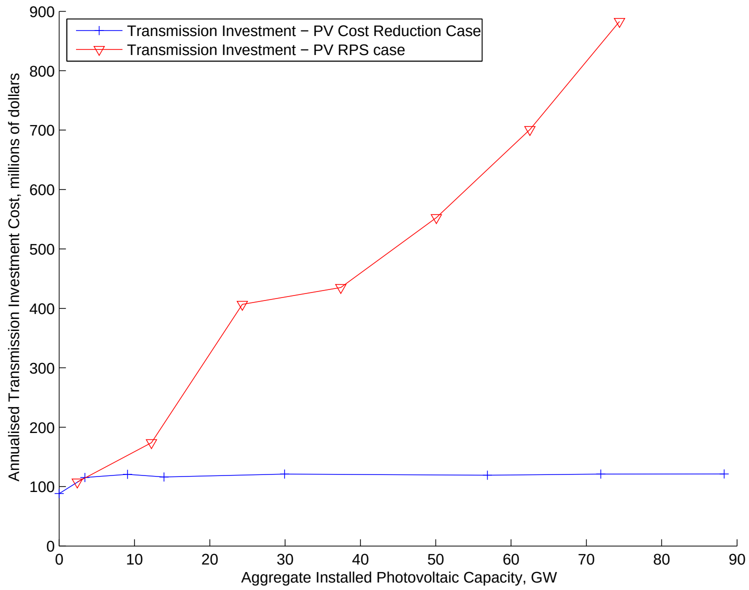

Figure 9-3: Transmission Investment versus PV Capacity for Both Deployment Paths
Repeated from Section 6.3.1

large-scale deployment of each.

- Solar power will lead to shifts in the shape of the price duration curve at each node, and a reduction in market prices in general. The nature of the shift in the price duration curve was different for the PV and CSP deployment scenarios (Sections 6.3.4 and 6.4.4).

- The impact of solar power deployment on carbon emissions was found to vary depending on the counterfactual assumptions chosen (as displayed for the photovoltaic case in Figure 9-6).

From Focus on Transmission (Chapter 8):

- It has been shown that under perfect (unrealistic) conditions, no transmission charge should be allocated to a solar generator, with nodal prices providing an appropriate locational signal. Otherwise, investment decisions will be distorted from the equilibrium point.

- Possible circumstances where a charge could potentially be warranted are where the solar generator is receiving a margin for locating in a non-system optimum fashion (as is shown to be possible under a flat feed-in-tariff support method), or the realistic

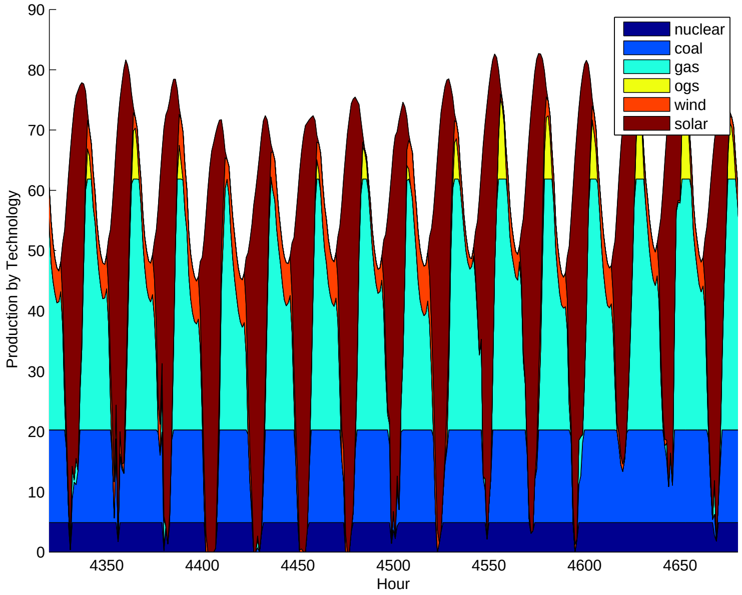

Figure 9-4: Production Profile for 15 Sample Summer Days
30% annual electric energy provided by PV. Repeated from Section 6.3.2

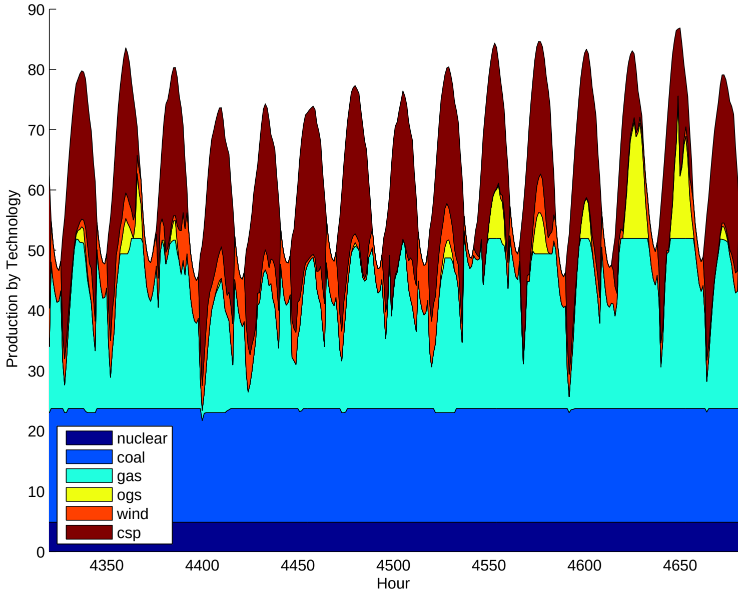

Figure 9-5: Production Profile for 15 Sample Summer Days
37% annual electric energy provided by CSP. Repeated from Section 6.4.2

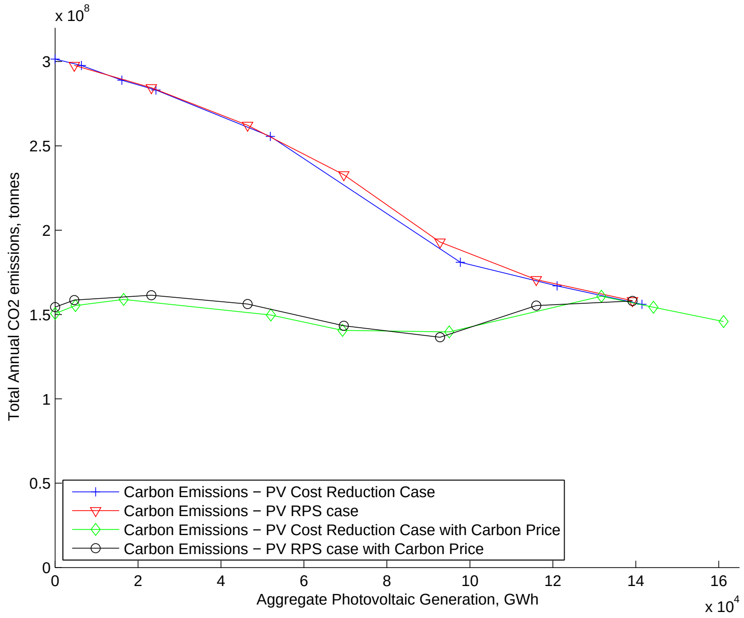

Figure 9-6: Carbon Emissions versus PV Generation (cost reduction and RPS cases)
In the carbon price cases, PV capacity replaces carbon-free nuclear capacity. Repeated from Section 6.3.3

dynamic situation where a transmission investment would have greater benefits than costs (and in the long term move the system closer to an optimum equilibrium).

- A preliminary investigation of the flat feed-in-tariff case highlighted the potential inefficiencies of the deployment of solar power if new solar generators do not see the location signals.

- Studying the benefits of transmission investment to incorporate solar power illustrates that the beneficiaries of transmission corridors are not confined to the associated end-generators and end-loads but users throughout the network to varying degrees. The results of the examples show that who benefits or who loses from a transmission line can be non-intuitive, making this a complex problem.

- Applying the Average Participations network usage estimation methodology as a proxy to Allocation of Beneficiaries returned reasonable, if non-ideal, results. The methodology appears less-arbitrary than other network usage methodologies that are commonly applied, as it is based on the actual flows in a system.

With the technical implications of large-scale solar power deployment garnered from a review of the literature (Section 3.1), and the presentation of many economic implications in the findings above, the regulatory implications are predominantly represented in the following Recommendations section.

Recommendations

- It was apparent from the literature that it makes sense to provide the incentives and develop the control systems so that PV inverters can provide grid services.
- Through this work, it is apparent that power systems could evolve in a number of very different ways in coming decades. Stable signals as regards carbon policy, subsidies to renewables, electric vehicles, demand response programs will all be required for efficient deployment of any range of technologies, solar power deployment or not.
- Depending on particular systems, some evidence was presented here of the potential synergies between wind and photovoltaic generation. This potentially could be considered in the design of support schemes and any resulting transmission plans.
- Considering the reduction in market prices noted at very high levels of solar power deployment, a capacity payment may be necessary to assure system adequacy in a less-deterministic world than that of the Expan model.
- As should be clear from the examples of Chapter 8, transmission charges, the system pricing scheme and renewable energy support schemes all need to be considered together - to produce a combined efficient outcome. In addition, renewable generators need to 'see' the resulting locational signals.

Many of the findings, particularly the regulatory and economic implications above, are valid for wind power. The only difference for solar power in these contexts is the distribution of the resource and the different temporal profile. While the high-level findings are practically equivalent, the system-specific impacts will thus vary. Also important differentiations exist between wind and solar power in the greater potential for photovoltaics as distributed generation, and the ability of concentrating solar power to include thermal storage.

To conclude, the goal of this thesis was to gain an understanding of the implications of large-scale solar power deployment on power systems. It is hoped that reading this resulting work will give: a) a 'policy-maker' greater insight into the implications of different solar power support policies, b) an investor an outline of what factors to consider should large-scale solar power deployment become a reality, and c) a regulator guidelines of how transmission pricing regulation could aid, or otherwise, the efficient deployment of solar power.

Chapter 10

Future Work

As the final phase of this document, a few words are provided here on potential future work that could further the understanding of the implications of large-scale solar power deployment. This proposed future work is broken down into two categories; a) background work that would facilitate the understanding of the relevant issues, and b) direct extensions from this thesis.

Background Tasks:

These tasks are classified as 'background' tasks as they are not direct extensions to this work but would aid the understanding of the issues in general.

- The inclusion of finer timescale representations of renewable energies in long term planning models or general equilibrium models that are related to the energy sector. This work has shown the relevance of wind and photovoltaic production patterns in investment decisions. It is acknowledged that this is a computationally challenging task.
- The requirement for higher spatial and temporal resolution solar radiation data to assess further the technical implications of large-scale solar power deployment is acknowledged by a number of studies.
- Additional work is required to understand the feasibility of maintaining stability on a power system at the higher levels of installed quantities of photovoltaics seen in some of the modelling outcomes.

Direct Tasks:

As apparent from Chapters 6 and 7, the models used in this thesis present a broad array of results. A number of tasks could be undertaken as direct extensions to the work of this thesis:

- The Expan model used the solar insolation profile of one historical year. The wind and demand data considered did not correspond to the same year, potentially missing relevant correlations. A sensitivity analysis using the historical data of different years could be useful in determining any major differences across covariance patterns of interest. Of course, a rigorous sensitivity analysis across all input parameters could be useful.

- Some potential cross-impacts between wind and solar power were highlighted. Further development of this line of inquiry using the developed framework could produce some interesting quantitative results of how the two technologies interact with each other.

- CSP was included in the modelling work, however considering the less-controllable nature of PV output, significantly less focus was placed on CSP in the consideration of the marginal value of a renewable generator in a network (Section 5.4), and in the discussion on transmission (Chapter 8). Considering the non-linear nature of CSP output relative to incoming solar radiation, the number of possible CSP design options, and the potential benefits CSP with storage could provide the power system, further analysis be a useful line of inquiry.

- The Expan model and its associated analytical development could potentially be applied to a more realistic representation of a power system as opposed to the 7-node system used in this document. This approach could run into computational limitations however.

- Designing and implementing the analysis of Chapter 8 highlighted some interesting points of divergence between centralised electricity models and market models. To provide a more thorough assessment of the behaviour of investors and existing generators under both transmission charges and flat feed-in-tariffs, an appropriately designed market model would be a positive development. This task is of a less incremental nature than other tasks in this section.

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Appendix A

GAMS Code of Base Expan Model

```
*PV_GAMSMaster.gms - File to automatically call Expan.gms
*across a range of cost scenarios

$call gams 8760_reform.gms --instance=100         lo=2 o=100.lst lf=100.log
$if errorlevel 1 $abort 'problems with instance 100'

$call gams 8760_reform.gms --instance=60
$if errorlevel 1 $abort 'problems with instance 60'

$call gams 8760_reform.gms --instance=50
$if errorlevel 1 $abort 'problems with instance 50'

$call gams 8760_reform.gms --instance=40
$if errorlevel 1 $abort 'problems with instance 40'

$call gams 8760_reform.gms --instance=35
$if errorlevel 1 $abort 'problems with instance 35'

$call gams 8760_reform.gms --instance=30
$if errorlevel 1 $abort 'problems with instance 30'

$call gams 8760_reform.gms --instance=25
$if errorlevel 1 $abort 'problems with instance 25'

$call gams 8760_reform.gms --instance=20
$if errorlevel 1 $abort 'problems with instance 20'

$call gams 8760_reform.gms --instance=15
$if errorlevel 1 $abort 'problems with instance 15'

$call gams 8760_reform.gms --instance=10           lo=2 o=10.lst lf=10.log
$if errorlevel 1 $abort 'problems with instance 10'
```

```
$TITLE Expan Model
*Developed for Master's Thesis of:
*James Merrick, TPP/Course 6, Massachusetts Institute of Technology

*Expan.gms

Option iterlim = 10000000 ;
Option reslim = 80000 ;

* Code adapted from original formulation of:
* Professor Andres Ramos

SETS
   P     Dispatch Periods             / h1 * h8760  /
   QQ(p) Subset of Dispatch Periods  / h1 * h8760  /
   ND    Nodes                / node-60 * node-65, node-67 /
   TR    Generators /
         solar-61
         solar-62
         solar-63
         solar-60
         solar-64
         solar-65
         solar-67
         gas-61
         wind-61
         gas-62
         OGS-62
         wind-62
         wind-60
         gas-60
         OGS-60
         coal-60
         gas-63
         OGS-63
         coal-63
         nuclear-63
         gas-64
         OGS-64
         coal-64
         gas-67
         OGS-67
         coal-67
         gas-65
         OGS-65
         coal-65
         nuclear-65
                              /

   TRw(TR) Wind Subset of Generators   / wind-61,wind-62,wind-60  /
   TRn(TR) Nuclear Subset of Generators  / nuclear-63,nuclear-65/
   TRc(TR) Coal Subset of Generators  /coal-60, coal-63,coal-64,
   coal-67, coal-65/
   TRg(tr) Gas Subset of Generators   /gas-61, gas-62,gas-60,gas-63,
```

```
   gas-64,gas-67,gas-65,ogs-62*ogs-65,ogs-60,ogs-67/
   TRgas(tr) Gas Subset of Generators (excluding OGS)   /gas-61, gas-62,
   gas-60,gas-63, gas-64,gas-67,gas-65/
   TRs(tr) Solar Subset of Generators   /solar-61,solar-62,solar-60,solar-63,
   solar-64,solar-65,solar-67/
   TRth(tr) Conventional Subset of Generators   /nuclear-63,nuclear-65,coal-60,
   coal-63,coal-64,coal-67, coal-65,gas-61, gas-62,gas-60,gas-63, gas-64,gas-67,
   gas-65,ogs-62*ogs-65,ogs-60,ogs-67/
   TRogs(tr) OGS Subset of Generators   /ogs-62*ogs-65,ogs-60,ogs-67/
   TRr(tr) Renewable Subset of Generators   /solar-61,solar-62,solar-60,solar-63,
   solar-64,solar-65,solar-67,wind-61,wind-62,wind-60  /

   ATG   Generator Attributes
        / pmx, pmn, cvr, efor, q1, cfj,fc, tcf,  co2 /

   ATL   Line Attributes / r, x, flmx, cfj, tcf, Length /
   NDTR(nd,tr) Location of Generators
   /
    node-61.solar-61
    node-61.gas-61
    node-61.wind-61
    node-62.solar-62
    node-62.gas-62
    node-62.OGS-62
    node-62.wind-62
    node-60.solar-60
    node-60.wind-60
    node-60.gas-60
    node-60.OGS-60
    node-60.coal-60
    node-63.solar-63
    node-63.gas-63
    node-63.OGS-63
    node-63.coal-63
    node-63.nuclear-63
    node-64.solar-64
    node-64.gas-64
    node-64.OGS-64
    node-64.coal-64
    node-67.solar-67
    node-67.gas-67
    node-67.OGS-67
    node-67.coal-67
    node-65.solar-65
    node-65.gas-65
    node-65.OGS-65
    node-65.coal-65
    node-65.nuclear-65
   /

s                Segments for the cosine approximation/k1*k8/
as               Atributes of each segment            /m,n/

LE(nd,nd) Line Connections
```

```
 ALIAS (nd,ni,nf)

SCALARS
   SBASE  Base Power (GW)                   / 1 /
   Vll  LineLineVoltage                   / 1000e3 /
*for the purposes of equation vdash = 1000e3^2/1e9 (division to convert RHS of FLJE to GW)
   Vdash  LineLineVoltage                   / 1000 /
   CSL    Line Security Coefficient         / 1 /

PARAMETERS
   INCDEM         Demand Increment Factor
   INC            Fraction of Demand Increase /   0.486/
   PCTND(nd)      Division of Demand by Node           /
node-60           0.014217036
node-61           0.023109936
node-62           0.016747394
node-63           0.392874732
node-64           0.127133063
node-65           0.197620585
node-67           0.228297255
/ ;
*Demand breakdown from ReEDS Model

INCDEM =  1+INC ;

*Call file with generator data
$include DTGT.txt

*Convert to M
dtgt(tr,'cvr')=dtgt(tr,'cvr')/1e6;
dtgt(tr,'FC')=dtgt(tr,'FC')/1e6;
dtgt(tr,'cfj')=dtgt(tr,'CFJ')/1e6;

*This is the method by which automatic cost reductions are implemented
scalar chance/100/;
$ifthen %instance%==100
chance=100;
$endif
$ifthen %instance%==60
chance=60;
$endif
$ifthen %instance%==50
chance=50;
$endif
$ifthen %instance%==40
chance=40;
$endif
$ifthen %instance%==35
chance=35;
$endif
$ifthen %instance%==30
chance=30;
$endif
```

```
$ifthen %instance%==25
chance=25;
$endif
$ifthen %instance%==20
chance=20;
$endif
$ifthen %instance%==15
chance=15;
$endif
$ifthen %instance%==10
chance=10;
$endif

*Following two lines modify fixed costs of solar capacity
dtgt(trs,'FC')=dtgt(trs,'FC')*(chance/100);
dtgt(trs,'cfj')=dtgt(trs,'CFJ')*(chance/100);

Parameter DEM(p);
$include demand.txt

TABLE DTLE(ni,nf,atl) Transmission Line Details
                      r        x    flmx    cfj      tcf    Length
*                                    MW      $                miles
node-61 . node-62   0.0564  0.596    832   1205000    0.1      74
node-62 . node-60   0.0564  0.596   2303   1205000    0.1      171
node-61 . node-60   0.0564  0.596   2473   1205000    0.1      234
node-60 . node-63   0.0564  0.596   2003   1205000    0.1      173
node-63 . node-64   0.0564  0.596   4440   1205000    0.1      302
node-61 . node-63   0.0564  0.596    456   1205000    0.1      328
node-61 . node-64   0.0564  0.596    238   1205000    0.1      295
node-61 . node-65   0.0564  0.596    466   1205000    0.1      354
node-64 . node-67   0.0564  0.596   2207   1205000    0.1      170
node-64 . node-65   0.0564  0.596   6298   1205000    0.1      148
node-65 . node-67   0.0564  0.596   6360   1205000    0.1      204
node-63 . node-67   0.0564  0.596   2138   1205000    0.1      241
 ;

DTLE(ni,nf,'R')=DTLE(ni,nf,'r')*DTLE(ni,nf,'Length');
DTLE(ni,nf,'X')=DTLE(ni,nf,'x')*DTLE(ni,nf,'Length') ;
*These values for resistance and reactance are from Bergen&Vittal page 85

*Convert to M
DTLE(ni,nf,'cfj')=DTLE(ni,nf,'cfj')/1e6;

$ontext
Page 50 of REALISEGRID report has a HVAC OHL single circuit rating of 1500MVA
with a cost range of 400-700 k/km
500,000/km = 805,000/mile = $1,205,000/mile
$offtext

LE(ni,nf) $DTLE(ni,nf,'x') = YES ;

Table ds(s,as)
            m                       n
```

```
k1       -0.993060583       -0.560393213
k2       -0.869687845       -0.410544975
k3       -0.526814649       -0.141932029
k4       -0.054958854       -0.001098792
k5       0.044973831       -0.000599461
k6       0.430352786       -0.093745374
k7       0.86471337       -0.405320389
k8       0.991855854       -0.558644769
;

Parameter WindFactor(p,trw);
$include windfactor2.txt

Parameter solarInsolationFactor(p,trs);
$include TexInsolationFactorV1.txt
*The TexInsolationFactorV1 file has insolation profiles for each node

Parameter PF(p,tr);
PF(p,tr)=1;
PF(p,trw)=windfactor(p,trw);
PF(p,trs)=solarinsolationfactor(p,trs)/1000;

display pf;

Parameter NodalDemand(qq,nd);
NodalDemand(qq,nd)= (PCTND(nd) * DEM(qq) * INCDEM);
Display Nodaldemand;

*Convert to GW
DTGT(tr,'pmx')     = DTGT(tr,'pmx')     / 1e3 ;
DTGT(tr,'pmn')     = DTGT(tr,'pmn')     / 1e3 ;
DEM(p)           = DEM(p)           / 1e3 ;
nodaldemand(qq,nd)=nodaldemand(qq,nd)/1e3;
DTLE(ni,nf,'flmx') = DTLE(ni,nf,'flmx') / 1e3 ;

*Integer variable
* TTC(ni,nf)     New Transmission Capacity Investment
VARIABLES
   PTP(p,tr)             Production      (GW)
   TT(p,nd)              Node Angle      (rad)
   FLE(p,ni,nf)          Line Flow       (GW)
   PTI(tr)               New Installed Capacity     (GW)
   TTC(ni,nf)            New Transmission Capacity Investment (GW)
   L(p,ni,nf)        Losses per line     (GW)
   CSTTL                 Objective Function Cost (M$)
   CO2var                Carbon Emissions(tonnes)
;

POSITIVE VARIABLES  PTP,  PTI, co2var, L;
Positive variable TTC            ;

EQUATIONS
   FO              Objective Function
   KR1(p,nd)       Kirchoff's 1st law for each node
```

```
   e_loss(qq,ni,nf,s) Transmission Losses
   FLJE(p,ni,nf)   Flow Constraint
   PRDTRM(p,tr)    Generation less than capacity in each hour constraint
   NewTran1(p,ni,nf)             New Transmission Constraint1
   NewTran2(p,ni,nf)             New Transmission Constraint 2
   carbonconstraint  Carbon constraint
   solar_req       Solar RPS
;

FO .. CSTTL =E=
SUM((tr),    PTI(tr)    * DTGT(tr,’cfj’)*DTGT(tr,’tcf’) )
+SUM((tr),   ((PTI(tr)+DTGT(TR,’PMX’))     * DTGT(tr,’FC’)))
+SUM((qq,tr),    DTGT(tr,’cvr’) * PTP(qq,tr) )
+SUM((le(ni,nf)),TTC(ni,nf)* DTLE(ni,nf,’cfj’)*DTLE(ni,nf,’tcf’)*DTLE(ni,nf,’Length’) )
+(co2var*0e-5)
;

KR1(qq,nd) ..
   SUM(NDTR(nd,tr), PTP(qq,tr))
 + SUM(LE(ni,nd), FLE(qq,ni,nd)) - SUM(LE(nd,nf), FLE(qq,nd,nf))
    =e= nodaldemand(qq,nd)+
(sum(le(ni,nd),L(qq,ni,nd))/2)+
(sum(le(nd,nf),L(qq,nd,nf))/2)
 ;

E_LOSS(qq,LE(ni,nf),s) ..
L(qq,ni,nf) =G= Vdash * 2 * [dtle(ni,nf,’R’)/ (dtle(ni,nf,’R’)**2
+ dtle(ni,nf,’X’)**2)]* [ds(s,’m’)*(TT(qq,ni) - TT(qq,nf)) + ds(s,’n’)] ;

FLJE(qq,LE(ni,nf)) ..
   FLE(qq,ni,nf) =E= (Vdash*(TT(qq,ni)-TT(qq,nf)))/DTLE(ni,nf,’X’) ;

PRDTRM(qq,tr) ..
   PTP(qq,tr)=l= (DTGT(tr,’pmx’) + PTI(tr)) *(1-DTGT(tr,’efor’)) *PF(qq,tr);

Solar_Req ..
sum((p,trs),ptp(p,trs))=g=(chance/100)*  SUM((p),(dem(p) * INCDEM));

NewTran1(qq,LE(ni,nf)) ..
   FLE(qq,ni,nf) =L= (DTLE(ni,nf,’flmx’) +
   1.5*TTC(ni,nf))*CSL ;

NewTran2(qq,LE(ni,nf)) ..
 -  FLE(qq,ni,nf) -((DTLE(ni,nf,’flmx’)
+   1.5*TTC(ni,nf))*CSL )=l=0 ;

carbonconstraint ..
CO2VAR=e=sum((p,tr),(dtgt(tr,’CO2’)*ptp(p,tr)));

TT.LO(p,nd)       = -1.5 ;
TT.UP(p,nd)       =  1.5 ;
TT.FX(p,’node-65’) =  0 ;

MODEL PLGNRD   / FO,
```

```
 KR1,
 FLJE,
PRDTRM,
e_loss
NewTran1,
NewTran2,
carbonconstraint
*solar_req
 /;


pti.up(trogs)=0;

plgnrd.dictfile=0;
option solvelink=0 ;

plgnrd.optfile=1;

option  optcr=0.0001;

option MIP=cplex, NLP=coinos, MINLP=emp, LP=cplex

SOLVE PLGNRD USING LP MINIMIZING CSTTL ;

*File where output parameter values are calculated
$include Parameter_Calculations.gms

* Now Output to GDX file
execute_unload '8760_reform_output%instance%.gdx' sumgeneration,gen,gen_gas,
gen_solar, gen_wind,gen_coal,gen_ogs,gen_nuclear,cap,cap_gas,cap_solar,
cap_wind,cap_ogs,cap_coal,cap_nuclear,existcap,tran,CO2,generation_tech,
sumgeneration,nodaldemand,capacityfactor,solar_surp,wind_surp,losses,
traninvest,fcg,E_lambda_nd,trancap6162,trancap6260,trancap6160,trancap6063,
trancap6364,trancap6163,trancap6164,trancap6165,trancap6467,trancap6465,
trancap6567,trancap6367,lambda60, lambda61, lambda62, lambda63, lambda64,
lambda65, lambda67,genh_gas, genh_solar, genh_wind, genh_coal, genh_nuclear,
genh_ogs,capcost_nuclear,capcost_coal,capcost_gas,capcost_wind,capcost_solar,
gencost_nuclear,gencost_coal,gencost_gas,gencost_wind,gencost_solar,
gencost_ogs,f,nodalgen,L.l,nodaldemand_with_losses,networkinvestment;
```

Appendix B

Sample MATLAB Code to Plot Figures

```
%James Merrick
%TPP / Course 6
%Massachusetts Institute of Technology

%Sample of MATLAB code to process and plot GDX results
%This sample plots the capacity figures only

i=1;

clear x
for chance=[100 60 50 40 35 30 25 20 15 10]

index=num2str(chance);
call_file=strcat('8760_reform_output',index,'.gdx');

%For graph x-axis, need FCG_Solar
[FCG, uels]=readgdx(call_file,'fcg');
for j=1:length(FCG)
    if FCG(j,1)==8774
        x(i)=FCG(j,2);
        break
    end
end

%Garner Capacity Results from GDX file
%First, capacity investment by technology

%Gas Capacity
[pti_gas, uels]=readgdx(call_file,'cap_gas');
gas_cap_total=sum(pti_gas);
gascap(i)=gas_cap_total;

%Solar Capacity
```

```
[pti_solar, uels]=readgdx(call_file,'cap_solar');
solarcap(i)=sum(pti_solar);
%Wind Capacity
[pti_wind, uels]=readgdx(call_file,'cap_wind');
windcap(i)=sum(pti_wind);
%Coal Capacity
[pti_coal, uels]=readgdx(call_file,'cap_coal');
coalcap(i)=sum(pti_coal);
%Nuclear Capacity
[pti_nuclear, uels]=readgdx(call_file,'cap_nuclear');
nuclearcap(i)=sum(pti_nuclear);

totalcap(i)=gascap(i)+solarcap(i)+windcap(i)+coalcap(i)+nuclearcap(i);

%1a, solar capacity broken down
cap=readgdx(call_file,'cap');
solar_cap_61(i)=zeros(1,length(chance));
solar_cap_62(i)=zeros(1,length(chance));
solar_cap_63(i)=zeros(1,length(chance));
solar_cap_60(i)=zeros(1,length(chance));
solar_cap_64(i)=zeros(1,length(chance));
solar_cap_65(i)=zeros(1,length(chance));
solar_cap_67(i)=zeros(1,length(chance));

for j=1:length(cap)
    if cap(j,1)==8768
        solar_cap_61(i)=cap(j,2);
    elseif cap(j,1)==8769
        solar_cap_62(i)=cap(j,2);
    elseif cap(j,1)==8770
        solar_cap_63(i)=cap(j,2);
    elseif cap(j,1)==8771
        solar_cap_60(i)=cap(j,2);
    elseif cap(j,1)==8772
        solar_cap_64(i)=cap(j,2);
    elseif cap(j,1)==8773
        solar_cap_65(i)=cap(j,2);
    elseif cap(j,1)==8774
        solar_cap_67(i)=cap(j,2);
        end
end

exist=readgdx(call_file,'existcap');
gas_old=exist(1,2)+exist(3,2)+exist(7,2)+exist(10,2)+exist(14,2)+exist(17,2)+exist(20,2);
coal_old=exist(9,2)+exist(12,2)+exist(16,2)+exist(19,2)+exist(2,2);
nuclear_old=exist(13,2)+exist(23,2);
wind_old=exist(2,2)+exist(5,2)+exist(6,2);
ogs_old=exist(4,2)+exist(8,2)+exist(11,2)+exist(15,2)+exist(18,2)+exist(21,2);

%end up loop
i=i+1;
end

%Now plot associated results
```

```
figure (1)
hold on;
plot(x,gascap,'bx-')
plot(x,solarcap,'go-')
plot(x,windcap,'r^-')
plot(x,coalcap,'c+-')
plot(x,nuclearcap,'ms-')
set(gca,'xdir','reverse')
xlabel('Annual Fixed Cost of a Unit of Photovoltaic Capacity, $/kW')
ylabel('New Installed Capacity, GW')
legend('Gas','Solar','Wind','Coal','nuclear','location','northwest')
print -depsc cap_mc
hold off;

figure (12)
hold on;
plot(solarcap,gascap,'bx-')
plot(solarcap,solarcap,'go-')
plot(solarcap,windcap,'r^-')
plot(solarcap,coalcap,'c+-')
plot(solarcap,nuclearcap,'ms-')
xlabel('Installed Photovoltaic Capacity, GW')
ylabel('New Installed Capacity, GW')
legend('Gas','Solar','Wind','Coal','nuclear','location','northwest')
print -depsc cap_cap
hold off;

figure (13)
hold on;
plot(solarcap,solar_cap_60,'bx-')
plot(solarcap,solar_cap_61,'go-')
plot(solarcap,solar_cap_62,'r^-')
plot(solarcap,solar_cap_63,'c+-')
plot(solarcap,solar_cap_64,'ms-')
plot(solarcap,solar_cap_65,'kd-')
plot(solarcap,solar_cap_67,'yh-')
xlabel('Cumulative Solar Capacity')
ylabel('New Installed Capacity, GW')
legend('Solar-60','Solar-61','Solar-62','Solar-63','Solar-64','Solar-65','Solar-67')
print -depsc solarcap_cap
hold off;

figure (16)
hold on;
plot(x,gascap+gas_old,'bx-')
plot(x,solarcap,'go-')
plot(x,windcap+wind_old,'r^-')
plot(x,coalcap+coal_old,'c+-')
plot(x,nuclearcap+nuclear_old,'ms-')
plot(x,ogs_old,'kd-')
set(gca,'xdir','reverse')
xlabel('Annual Fixed Cost of a Unit of Photovoltaic Capacity, $/kW')
ylabel('Total Capacity, GW')
legend('Gas','Solar','Wind','Coal','Nuclear','Oil-Gas-Steam','location','northwest')
```

```
print -depsc mc_totalcap
hold off;

figure (17)
hold on;
plot(solarcap,gascap+gas_old,'b')
plot(solarcap,solarcap,'g')
plot(solarcap,windcap+wind_old,'r')
plot(solarcap,coalcap+coal_old,'c')
plot(solarcap,nuclearcap+nuclear_old,'m')
plot(solarcap,ogs_old,'y')
xlabel('Installed Photovoltaic Capacity, GW')
ylabel('Total Capacity, GW')
legend('Gas','Solar','Wind','Coal','nuclear','location','northwest')
print -depsc solarcap_totalcap
hold off;
```

Appendix C

MATLAB Code to Implement Average Participations Algorithm

```
%James Merrick, June 2010
%Implementation of AP Method (and Modified AP Method) using output
%from GAMS code via GDX file

%Remember this method is an estimate of the use of each transmission line
%by each network entity

%The following two matrices represent the cumulative Average Participations
%contribution by demand and generation at each node
%Element (i,j) is the contribution of node i to line j
MOT_d_count=zeros(7,12); %Demand
MOT_g_count=zeros(7,12); %Generation

%Used for future weighting across 8760 hours
F_count=zeros(12,1);
Cgn_count=zeros(7,12);

%Here, enter the gdx file of your choice to call
call_file='8760_reform_RPS_discrete_STMC_out.gdx';

%Extract flows, generation, and demand from gdx file
[F, uels]=readgdx(call_file,'f');
[NG, uels]=readgdx(call_file,'nodalgen');
[D, uels]=readgdx(call_file,'nodaldemand_with_losses');

%A quick check to determine what is the capacity of solar in the called
%file
solarcap=readgdx(call_file,'cap_solar');
fprintf('\nSolar Capacity in this run is %g GW\n',solarcap);

%Connect what nodes transmission lines connect
con2=[8761 8764
      8762 8761
```

```
      8762 8763
      8762 8764
      8762 8765
      8762 8766
      8763 8761
      8764 8765
      8764 8767
      8765 8766
      8765 8767
      8766 8767];

% To have lines representing positive flows only for calculation simplicity
% later
for i=1:length(F)
    if F(i,4)<0
        swap1=F(i,2);
        swap2=F(i,3);
        F(i,2)=swap2;
        F(i,3)=swap1;
        F(i,4)=-F(i,4);
    end
end

%The average participations algorithm is solved for each hour and then a
%weighted average is taken over 8760 hours

for hr=1:8760
if hr>1
clear F1, clear G1, clear D1, clear SumFout    ;
end

%Extract the flows for each hour in question
k=1;
F1=[hr*ones(12,1) con2 zeros(12,1)];
for i=1:length(F)
if F(i,1)==hr,
if (F(i,2)==con2(k,1)&&F(i,3)==con2(k,2))||(F(i,2)==con2(k,2)&&F(i,3)==con2(k,1))
            F1(k,:)=F(i,:);
            k=k+1;
            else
                F1(k,1)=F(i,1);
                F1(k,2)=con2(k,1);
                F1(k,3)=con2(k,2);
                F1(k,4)=0;
                F1(k+1,:)=F(i,:);
                k=k+2;
            end
       end
end

%Extract demand for the current hour of interest
k=1;
for i=1:length(D)
        if D(i,1)==hr,
```

```
            D1(k,:)=D(i,:);
            k=k+1;
        end
end

%Extract nodal generation for the current hour of interest
G1=[hr*ones(7,1) D1(:,2) zeros(7,1)];
k=1;
for i=1:length(NG)
        if NG(i,1)==hr,
                    if NG(i,2)==G1(k,2),
                        G1(k,:)=NG(i,:);
                        k=k+1;
                    else
                        G1(k,3)=0;
                        G1(k+1,:)=NG(i,:);
                        k=k+2;
                        end
        end
end

con=[F1(:,2) F1(:,3)];


%First, we will consider contribution of generators

%The average participations contribution of generation at node i to usage of node j
MOT_g=zeros(7,12);

%Total flow exiting the node (including demand at that node)
for i=1:length(D1)
SumFout(i,1)=G1(i,2);
SumFout(i,2)=D1(i,3);
for k=1:length(F1)
if  F1(k,2)==G1(i,2) && F1(k,4)>0
    SumFout(i,2)=SumFout(i,2)+F1(k,4);
end

end

end
%Total flow exiting the node excluding demand at that node
SumFout_out(:,2)=SumFout(:,2)-D1(:,3);

%Now calculate the contribution of each generator to flows throughout the
%system
for t=1:length(G1)

%Now core calculations
for i=1:length(con)
    if F1(i,2)==G1(t,2) && F1(i,4)>0
       MOT_g(t,i)=MOT_g(t,i)+((G1(t,3)/SumFout(t,2))*F1(i,4));
        tracki=((G1(t,3)/SumFout(t,2))*F1(i,4));
        for w=1:length(con)
```

```
            if F1(w,2)==F1(i,3)
MOT_g(t,w)=MOT_g(t,w)+((tracki/(SumFout((find(SumFout(:,1)==con(w,1))),2)))*F1(w,4));
trackw=((tracki/(SumFout((find(SumFout(:,1)==con(w,1))),2)))*F1(w,4));
                for q=1:length(con)
                    if F1(q,2)==F1(w,3)
MOT_g(t,q)=MOT_g(t,q)+((trackw/(SumFout((find(SumFout(:,1)==con(q,1))),2)))*F1(q,4));
trackq=((trackw/(SumFout((find(SumFout(:,1)==con(q,1))),2)))*F1(q,4));
                        for r=1:length(con)
                    if F1(r,2)==F1(q,3)
MOT_g(t,r)=MOT_g(t,r)+((trackq/(SumFout((find(SumFout(:,1)==con(r,1))),2)))*F1(r,4));
trackr=((trackq/(SumFout((find(SumFout(:,1)==con(r,1))),2)))*F1(r,4));
                           for p=1:length(con)
                    if F1(p,2)==F1(r,3)
MOT_g(t,p)=MOT_g(t,p)+((trackr/(SumFout((find(SumFout(:,1)==con(p,1))),2)))*F1(p,4));
trackp=((trackr/(SumFout((find(SumFout(:,1)==con(p,1))),2)))*F1(p,4));

                           for last=1:length(con)
                            if F1(last,2)==F1(p,3)
             fprintf(’There is another flow to track [Generation] at hour %g\n’,hr)
                                            end
                           end
                           end
                           end
                         end
                        end
                      end
                end
            end
          end
        end
end
end


%Now implement check that all flows have been allocated
sum_MOT_g=sum(MOT_g,1);
check_g=sum_MOT_g’-F1(:,4);
if norm(sum_MOT_g’-F1(:,4))>.05
    fprintf(’There is a difference in flows at 0.05 threshold at hour %g\n’,hr);
end
if norm(sum_MOT_g’-F1(:,4))>.0001
    fprintf(’There is a difference in flows at 0.0001 threshold at hour %g\n’,hr);
end

%Now, normalise contribution of line
for i=1:length(con)
  for j=1:length(G1)
      if sum_MOT_g(i)>0
MOT_g_n(j,i)=MOT_g(j,i)/sum_MOT_g(i);
      else
          MOT_g_n(j,i)=0;
      end
      %Multiply by flows in order to get weighted average by flow later
      MOT_g_n_w(j,i)=      MOT_g_n(j,i)*F1(i,4);
```

```
      end
end

%Keep count for future weighting
F_count=F_count+F1(:,4);
MOT_g_count=MOT_g_count+MOT_g_n_w;


%Now we will consider contribution of demand

MOT_d=zeros(7,12);

%Sum of flows entering a node (including generation at that node)
for i=1:length(D1)
SumFin(i,1)=D1(i,2);
SumFin(i,2)=G1(i,3);
for k=1:length(F1)
if  F1(k,3)==D1(i,2) && F1(k,4)>0
    SumFin(i,2)=SumFin(i,2)+F1(k,4);
end
end
end
%Sum of flows entering a node (excluding generation at that node)
SumFin_in(:,2)=SumFin(:,2)-G1(:,3);


%Will consider contribution of demand at each node sequentially
for t=1:length(D1)


%Now core calculations
for i=1:length(con)
    if F1(i,3)==D1(t,2) && F1(i,4)>0

        MOT_d(t,i)=MOT_d(t,i)+(D1(t,3)/SumFin(t,2))*F1(i,4);
        tracki=(D1(t,3)/SumFin(t,2))*F1(i,4);
        for w=1:length(con)
            if F1(w,3)==F1(i,2)
MOT_d(t,w)=MOT_d(t,w)+(tracki/(SumFin((find(SumFin(:,1)==con(w,2))),2))*F1(w,4));
trackw=(tracki/(SumFin((find(SumFin(:,1)==con(w,2))),2))*F1(w,4));

                for q=1:length(con)
                    if F1(q,3)==F1(w,2)
MOT_d(t,q)=MOT_d(t,q)+(trackw/(SumFin((find(SumFin(:,1)==con(q,2))),2))*F1(q,4));
trackq=(trackw/(SumFin((find(SumFin(:,1)==con(q,2))),2))*F1(q,4));
                        for r=1:length(con)
                        if F1(r,3)==F1(q,2)
MOT_d(t,r)=MOT_d(t,r)+(trackq/(SumFin((find(SumFin(:,1)==con(r,2))),2))*F1(r,4));
trackr=(trackq/(SumFin((find(SumFin(:,1)==con(r,2))),2))*F1(r,4));
                            for p=1:length(con)
                             if F1(p,3)==F1(r,2)
MOT_d(t,p)=MOT_d(t,p)+(trackr/(SumFin((find(SumFin(:,1)==con(r,2))),2))*F1(r,4));
                        for last=1:length(con)
                             if F1(last,3)==F1(p,2)
```

```
              fprintf(’There is another flow to track [Demand] at hour %g\n’,hr)
                            end
                        end
                    end
                    end
                    end
                    end
                    end
                end
            end
        end
    end
end
end

%Follow same procedures as for generation
sum_MOT_d=sum(MOT_d,1);

check_d=sum_MOT_d’-F1(:,4);
if norm(sum_MOT_d’-F1(:,4))>.05
    fprintf(’There is a difference in flows at 0.05 threshold at hour %g\n’,hr);
end
if norm(sum_MOT_d’-F1(:,4))>.1
    fprintf(’There is a difference in flows at 0.1 threshold at hour %g\n’,hr);
end

for i=1:length(con)
  for j=1:length(G1)
      if sum_MOT_d(i)>0
          MOT_d_n(j,i)=MOT_d(j,i)/sum_MOT_d(i);
      else
          MOT_d_n(j,i)=0;
      end
          MOT_d_n_w(j,i)=MOT_d_n(j,i)*F1(i,4);
  end
end


MOT_d_count=MOT_d_count+MOT_d_n_w;


%Calculate contributions as per LO&IPA approach (Modified Average
%Participations)
Fgn=SumFout_out(:,2)./(SumFout_out(:,2)+SumFin_in(:,2));
one_vector=ones(length(Fgn),1);
for i=1:7
    for j=1:12
Cgn(i,j)=Fgn(i)*MOT_g_n(i,j)-(one_vector(i)-Fgn(i))*(MOT_d_n(i,j));
Cgn_w(i,j)=Cgn(i,j)*F1(j,4);
    end
end
Cgn_count=Cgn_count+Cgn_w;

%This end then ends loop over all hours
```

```
end

%Now calculate weighted means
%These matrices are those used as outputs

for i=1:length(con)
    for j=1:length(G1)
MOT_d_count_weightedmean(j,i)=MOT_d_count(j,i)/F_count(i);
    end
end

for i=1:length(con)
    for j=1:length(G1)
MOT_g_count_weightedmean(j,i)=MOT_g_count(j,i)/F_count(i);

    end
end

for i=1:length(con)
    for j=1:length(G1)
Cgn_count_weightedmean(j,i)=Cgn_count(j,i)/F_count(i);
    end
end
```