KTH ROYAL INSTITUTE
OF TECHNOLOGY

Doctoral Thesis in Electrical Engineering

Optimisation and Incentive Mechanisms for Robust Generation Dispatch and Capacity Investment in Electricity Markets

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Stockholm, Sweden 2023

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Abstract

Power systems constitute a large-scale critical infrastructure and therefore, it is crucial that their operation be robust to deviations from normal functioning of its independent components. Furthermore, due to their large size, any inefficiencies in electricity market design can be very costly and therefore, must be optimised.

The first part of the thesis explores how generators must be optimally dispatched while maintaining robustness of the power system, which we model as the look ahead security constrained optimal power flow (LASCOPF) problem. LASCOPF optimises the generation dispatch given any objective, typically, a generation cost minimisation, over a planning horizon of multiple dispatch intervals, subject to physical constraints on the power system such as generator ramping constraints. In addition, we consider the $N-1$ contingency criterion, which is modelled as a set of security constraints that ensure that the system can transition to a feasible operating point if an outage in any one of its components were to occur. We observe that the problem size is quadratic in the number of intervals in the planning horizon and therefore, propose a reduced LASCOPF formulation for which the dependence is linear. We extend these results to the $N-k$ contingency criterion, which requires security against multiple simultaneous contingencies and observe that the problem size depends upon the number of permutations of contingencies. To overcome this, we propose a further reduced problem for which the dependence is on the number of permutations of contingencies. We model LASCOPF specifically using DC power flow under both generator and transmission line contingencies, and AC power flow under generator contingencies. For these, we prove that, barring borderline cases, the reduced formulations are equivalent to the corresponding comprehensive formulations. Numerical results on benchmark and real systems show that the reduced formulations have a significant computational advantage over the corresponding comprehensive ones.

The second part of the thesis explores how to use incentive mechanisms in electricity market design to overcome inefficiencies. The first problem we consider is that power generation causes environmental pollution with an associated damage cost, which we model as a negative externality. By definition, negative externalities are not included in the competitive market clearing used in electricity markets and, as we show, cannot be incorporated into the price. Since producers control generation sources, we propose a Pigouvian tax on them as an incentive to incorporate their pollution damage in their costs. The second problem we consider is producers' strategic behaviour where producers can declare higher costs to increase the prices and therefore, their profits. However, we show that even if producers are forced to declare costs truthfully, they may decrease their generation capacity to achieve the same effect. To overcome strategic behaviour of both these kinds, we propose to subsidise producers with their marginal contributions to the consumer surplus as an incentive. Our tax and subsidy mechanism is derived by aligning producers' profit maximisation with the social welfare maximisation resulting in an optimal generation dispatch.

The problems solved in this thesis contribute towards improving the efficiency of electricity markets by minimising generation costs and externalities such as environmental pollution while keeping the power system robust to outages in individual components.

Keywords: Optimal power flow, Look-ahead, $N-k$ contingency criterion, Renewable energy, Environmental externalities, Electricity generation capacity, Strategic behaviour, Incentives

Sammanfattning

Kraftsystem utgör en storskalig kritisk infrastruktur och därför är det avgörande att deras drift är robust mot avvikelser från normal funktion hos dess oberoende komponenter. Dessutom, på grund av deras stora storlek, kan eventuella ineffektiviteter i utformningen av elmarknaden bli mycket kostsamma och måste därför optimeras.

Den första delen av avhandlingen undersöker hur generatorer måste skickas optimalt samtidigt som robustheten hos kraftsystemet som vi modellerar som LASCOPF-problemet (*look ahead security constrained optimal power flow* på engelska). LASCOPF optimerar generationsutskick givet varje mål, typiskt en minimering av produktionskostnaden, över en planeringshorisont med flera sändningsintervall som är föremål för fysiska begränsningar på kraftsystemet såsom generatorrampningsbegränsningar. Dessutom överväger vi $N-1$-kontingenskriteriet som är modellerat som en uppsättning säkerhetsbegränsningar som säkerställer att systemet kan övergå till en genomförbar driftpunkt om ett avbrott i någon av dess komponenter skulle inträffa. Vi observerar att problemstorleken är kvadratisk i antalet intervall i planeringshorisonten och föreslår därför en reducerad LASCOPF-formulering där beroendet är linjärt. Vi utökar dessa resultat till $N-k$-kontingenskriteriet som kräver säkerhet mot flera samtidiga oförutsedda händelser och observerar att problemets storlek beror på antalet permutationer av oförutsedda händelser. För att övervinna detta föreslår vi ett ytterligare minskat problem där beroendet är av antalet permutationer av oförutsedda händelser. Vi modellerar LASCOPF specifikt med användning av DC-strömflöde under oförutsedda händelser i både generatorer och transmissionsledningar, och AC-strömflöde under oförutsedda händelser i generatorer. För dessa bevisar vi att, med undantag för gränsfall, de reducerade formuleringarna är likvärdiga med motsvarande omfattande formuleringar. Numeriska resultat på benchmark och verkliga system visar att de reducerade formuleringarna har en betydande beräkningsmässig fördel jämfört med motsvarande omfattande.

Den andra delen av avhandlingen utforskar hur man kan använda incitamentmekanismer i elmarknadsdesign för att övervinna ineffektivitet. Det första problemet vi tar upp är att elproduktion orsakar miljöföroreningar med tillhörande skadekostnader som vi modellerar som en negativ externitet. Per definition ingår inte negativa externa effekter i den konkurrensutsatta marknadsclearing som används på elmarknader och kan, som vi visar, inte inkorporerad i priset. Eftersom producenter kontrollerar produktionskällor, föreslår vi en Pigouvian skatt på dem som ett incitament att inkorporera deras föroreningsskador i deras kostnad. Det andra problemet vi överväger är producenternas strategiska beteende där producenter kan deklarera högre kostnader för att öka priserna och därmed deras vinster. Men vi visar att även om producenterna tvingas deklarera kostnader sanningsenligt, kan de minska sin produktionskapacite för att uppnå samma effekt. För att övervinna strategiskt beteende av båda dessa slag, föreslår vi att subventionera producenter med deras marginella bidrag konsumentöverskottet som ett incitament.

Vår skatte- och subventionsmekanism härleds genom att anpassa producenters vinstmaximering med den sociala välfärdsmaximeringen, vilket resulterar i en optimal generationsutskick.

De problem som lösts i denna avhandling bidrar till att förbättra effektiviteten på elmarknaderna genom att minimera produktionskostnader och externaliteter som miljöföroreningar samtidigt som kraftsystemet hålls robust mot avbrott i enskilda komponenter.

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Watch Dominion.

Contents

Chapter **1**

Introduction

1.1 Background

Power systems constitute a critical infrastructure, which serves the power needs of most people globally and on which almost all other infrastructures e.g., communication, transport etc. rely. Therefore, it is important to ensure their robustness to failures.

One can see the importance of robustness through the blackouts that have taken place throughout history such as the 1965 USA and Canada blackout [1], the 1978 Thailand blackout, the 2003 USA blackout [2] and the 2019 Argentina, Paraguay and Uruguay blackout. The 2003 Italy blackout [3] exposed the interdependence of power systems and communication networks in that both rely on each other for proper functioning. The failure of the power system resulted in a failure of the communication system and the lack of communication [4] in turn made hindered recovery of the power system, which required a coordinated effort at geographically distant locations. Most notably, the 2012 India blackouts [5] affected over 620 million people, making it the largest blackout in the history of the world.

Common to all the blackouts listed above is that they were caused by an outage in a single component, such as a transmission line or a generator. The effects of these outages cascaded into a series of contingencies throughout the grid and therefore caused system-wide blackouts. This reveals that the interconnected nature of the power systems makes it prone to cascading failures and therefore, in addition to ensuring that individual components are robust to contingencies, it is important to operate power systems in a manner in which the system as a whole is secure against contingencies in individual components.

In addition to ensuring security, an important problem pertaining to power systems is to ensure their sustainability. Sustainability is one of the central goals of society today and one of the most effective ways to ensure it is to decrease environmental pollution, in particular carbon emissions. Power generation is one of the major sources of carbon emissions. In 2021, globally, the emissions per unit

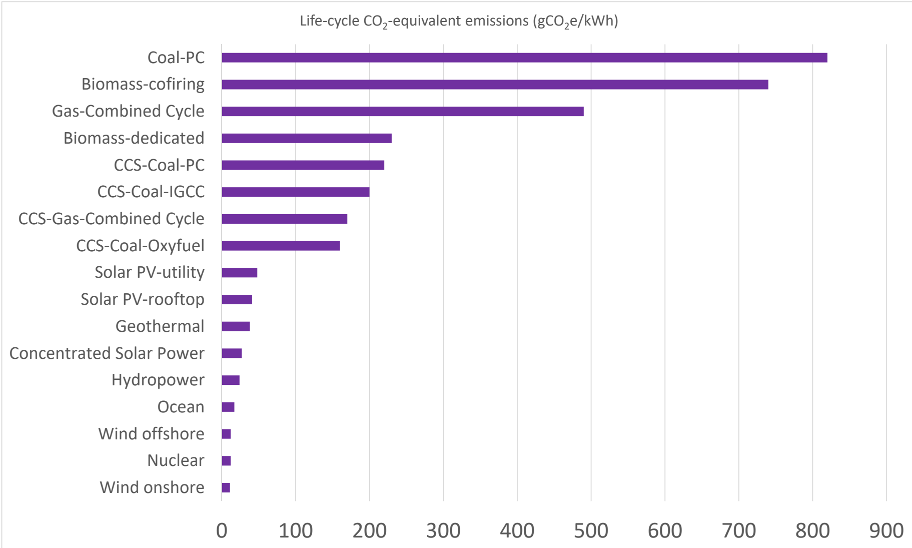

Figure 1.1: Median values of life-cycle greenhouse gas emissions for various generation sources.

of energy generated was $441gCO_2e/kWh$ (gram of carbon dioxide equivalents per kilowatt-hour of energy consumed) [6]. These must be drastically reduced in order to meet the goals set out by the Paris Agreement [7, 8].

Figure 1.1 shows that the emissions per unit energy vary drastically with the energy source based on data from [9]. Therefore, pollution can be significantly reduced if the design of electricity markets is such that low-polluting energy sources are prioritised. Figure 1.2 shows the share of electricity from low-polluting sources in Sweden, in all the continents and in the world over time based on data from [6]. As can be seen, globally, the share has remained almost constant. Therefore, to increase their share, investment in low-polluting energy sources must be encouraged.

However, low-polluting energy sources such as wind are highly intermittent [10] and therefore, their generation levels may vary significantly in short intervals of time. Also, they cannot be forecast accurately, and therefore, their actual generation levels may differ from their planned generation levels. Due to this, as their market share increases, the robustness of the system decreases. Therefore, robustness and sustainability of the power system are competing goals and it is important that they both be considered.

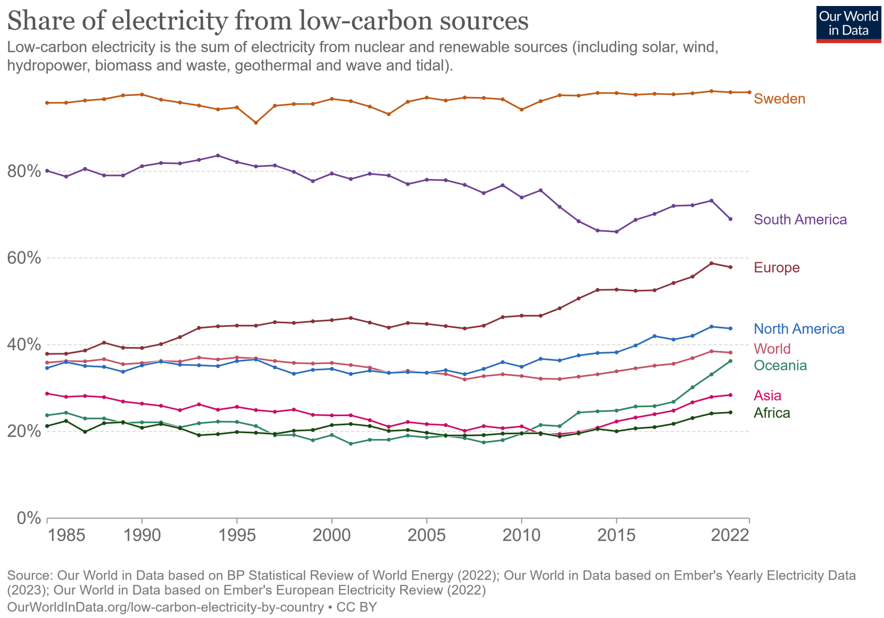

Figure 1.2: Share of electricity from low-polluting sources in Sweden, in all the continents and in the world from 1965 to 2022.

1.2 Stages of power system operation

Operation of the power system entails, amongst other things, dispatching generators and loads. Since, at the scale of power systems, electricity cannot be stored[1] and therefore, electricity must be consumed by loads at the same it is produced by generators. Therefore, electricity is traded in spot markets. Globally, electricity is typically traded in liberalised multi-settlement spot markets. First, based on a forecast, quantities are traded in forward markets. Then, in the real-time market, all that remains is to close the gaps between the forecast and realised quantities[2].

In Sweden, there is one forward market: the day-ahead market where electricity is bought and sold at exchanges such as Nordpool [11] and EPEX Spot [12]. Here, producers and consumers come together to trade electricity based on forecasts, e.g., weather forecasts that would determine the production of wind and demand forecasts that would determine consumer utilities. This is done in a way that satisfies the physical constraints of power systems. Forward markets are fo-

[1] While energy storage may be used, they are costly, their capacities are insignificant compared to the amount of energy exchanged.

[2] In this thesis, we do not discuss the Intraday market that offers another opportunity producers and consumers to trade their day-ahead positions before real-time delivery.

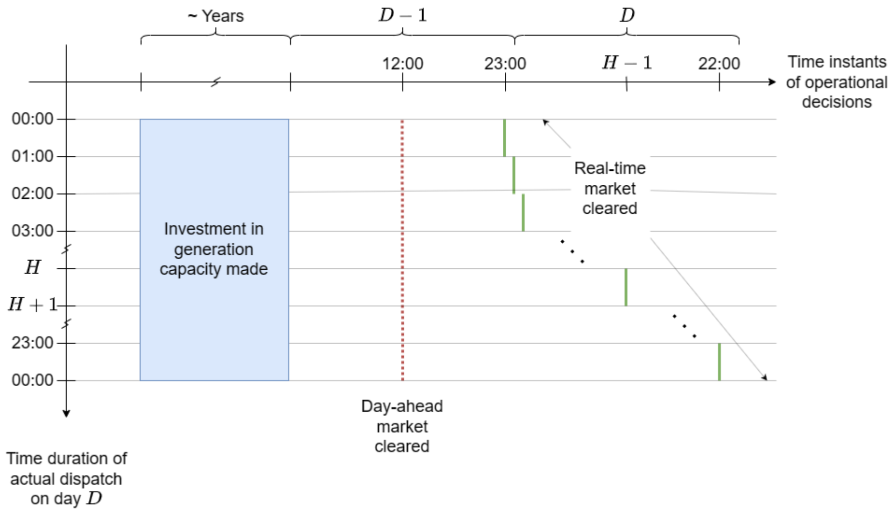

Figure 1.3: Timeline of the the different stages of power system operation.

cussed on improving the economic efficiency of electricity markets. Therefore, they are typically operated over larger geographical areas in order to allow cheaper generation resources to have a wider reach. E.g., Nordpool is jointly operated over the Nordic-Baltic region [11].

Figure 1.3 represents the different stages in the power system operation considered in this thesis based on the design of Swedish electricity markets. Since spot markets can only be cleared, i.e., generators and loads can only be dispatched at specific instants of time, time is discretised into dispatch intervals and the market is cleared for the end of every interval. In Sweden, a dispatch interval is one hour long [11]. As shown in Figure 1.3, the day-ahead market is cleared once per day at noon for all hours of the following day.

Unlike day-ahead markets, the focus of real-time markets is to robustly operate the power system. Since the forecasts made at the time of day-ahead market clearing may differ from the realised values, this entails settling imbalances in the system, i.e., ensuring that electricity generation matches the demand for electricity. In addition, the real-time market incorporates security against power contingencies and blackouts [13]. Therefore, to ensure control on the system real-time markets are operated by individual transmission system operators (TSOs). In Sweden, the TSO, Svenska kraftnät operates the real-time market in collaboration with TSOs of only the Nordic region using the Nordic balancing Model [14]. As shown in Figure 1.3, the real-time market is cleared an hour before the actual dispatch.

Based on their forecast of profits in the spot markets, producers make long-term investments in their generation capacity. As discussed previously, it is important for sustainability to ensure that investment is made in low-polluting energy sources. As shown in Figure 1.3, investment in generation capacity is made over a long timescale of years, where any decision would have an impact over a large number of spot market dispatch intervals.

Since power systems are utilised by almost all infrastructures, the scale of their operation and therefore, their operation costs are very high. The operation costs include, amongst others, generation costs and investment costs in generators and transmission lines. In 2022, globally, the amount of power generated was 27,812.74 TWh [6]. In Sweden alone, the amount was 171.68 TWh [6] and the averages prices varied from 634 SEK/MWh in the north to 1620 SEK/MWh in the south [15]. Therefore, even small improvements in the efficiency of electricity markets can result in huge gains.

1.3 Research questions

With the goal of ensuring the security and sustainability of the power system and improving the efficiency of electricity markets, this thesis attempts to answer the following research questions.

RQ1. An important way to ensure the robustness of power systems against contingencies is to securely dispatch generators such that, even if a contingency were to occur, the system can regain a stable operating state. This motivates the following question.

> How should generators be dispatched in the real-time market to ensure security against contingencies?

→ This question is answered in Papers A and B.

RQ2. Whilst environmental pollution in the power system must be minimised, it is a problem faced by society as a whole, not one that individual participants in the electricity markets consider. Therefore, environmental pollution is an externality. This motivates the following question.

> How can environmental externalities be incorporated in the electricity day-ahead market clearing?

→ This question is answered in Papers C and D.

RQ3. One of the biggest inefficiencies in electricity markets is the strategic behaviour of producers [16]. The price of electricity is decreasing in the amount of electricity produced. Therefore, producers may declare a false cost that is higher than their true cost at the time of market clearing in order to increase the prices [17]. While doing so may decrease their production, due to the increase in prices, their profits may increase. However, this increase of producers' profits is detrimental to the social welfare overall. This motivates the following question.

> How can producers be incentivised to not behave strategically in the electricity day-ahead market?

→ This question is answered in Paper C.

RQ4. Another way in which producers can behave strategically to increase prices is by withholding their generation capacity. This motivates the following question.

> How can producers be incentivised to not behave strategically while investing in generation capacity?

→ This question is answered in Paper D.

RQ5. Due to the large number of components involved, the operation of the power systems is computationally intensive. This motivates the following question.

> How can the computational complexity of the algorithm used to dispatch the generators be improved while preserving the quality of the solution?

→ This question is answered in Papers A and B.

1.4 Thesis structure

The remainder of this thesis is organised as follows. In Chapter 2, we model the components of the power system that will be required in other chapters. In Chapter 3, we model competitive market clearing in the day-ahead market and highlight the problems due to pollution and strategic generation. Furthermore, we discuss studies about these in literature and our solution to these problems in Papers C and D. In Chapter 4, we model the requirements of security in the real-time market and discuss how they have been incorporated in literature and in Papers A and B. In Chapter 5, we model the strategic generation capacity investment decisions of producers and how the investment in low-polluting energy sources may be less than what is socially optimal. Furthermore, we discuss studies about these in literature and our solution to these problems in Paper D. In Chapter 6, we provide a summary of the papers included in this thesis and discuss our contributions to the papers, and in Chapter 7, we conclude the thesis and discuss potential extensions of the work presented for the future.

Chapter 2

Power generation and transmission system

In this thesis, we model the power system as the aggregate of power generators and loads, the busses to which they are connected, and the transmission lines through which power is supplied. Figure 2.1 illustrates the components of the power system in the IEEE 30-bus test system [18]. The sections that follow present an abstraction of these components as would be required in later chapters to model the electricity spot markets and generation capacity investment.

2.1 Generators

The power system consists of a set of generators that employ various technologies and fuels, e.g., coal, wind and hydropower, to produce electricity. Let $\mathcal{J}$ denote the set of generators and j index individual busses such that $j \in \mathcal{J}$. The generation of a generator varies continuously over time. However, since the spot markets can only be cleared at specific instants of time, it is customary to discretise time into dispatch intervals and index individual intervals by t such that $t \in \mathbb{N}$[1]. In Sweden, a dispatch interval is one hour long [11].

For every generator j in every interval t, we denote by $p_j^t \in \mathbb{R}$ its active power generation level[2] [19], which lies within lower and upper capacity limits, $\underline{K}_j \in \mathbb{R}$ and $\overline{K}_j \in \mathbb{R}$, respectively, i.e.,

$$\underline{K}_j \leq p_j^t \leq \overline{K}_j \ \forall j \in \mathcal{J}, \forall t \in \mathbb{N}, \tag{2.1}$$

where $0 \leq \underline{K}_j \leq \overline{K}_j$ since p_j^t is non-negative. An availability factor A_j^t, where $0 \leq A_j^t \leq 1$, may also be attributed to certain technologies such as wind and solar,

[1] Here, $\mathbb{N}$ is the set of non-negative integers.

[2] This thesis does not address the subject of unit commitment and therefore, we assume for simplicity that all generators are committed.

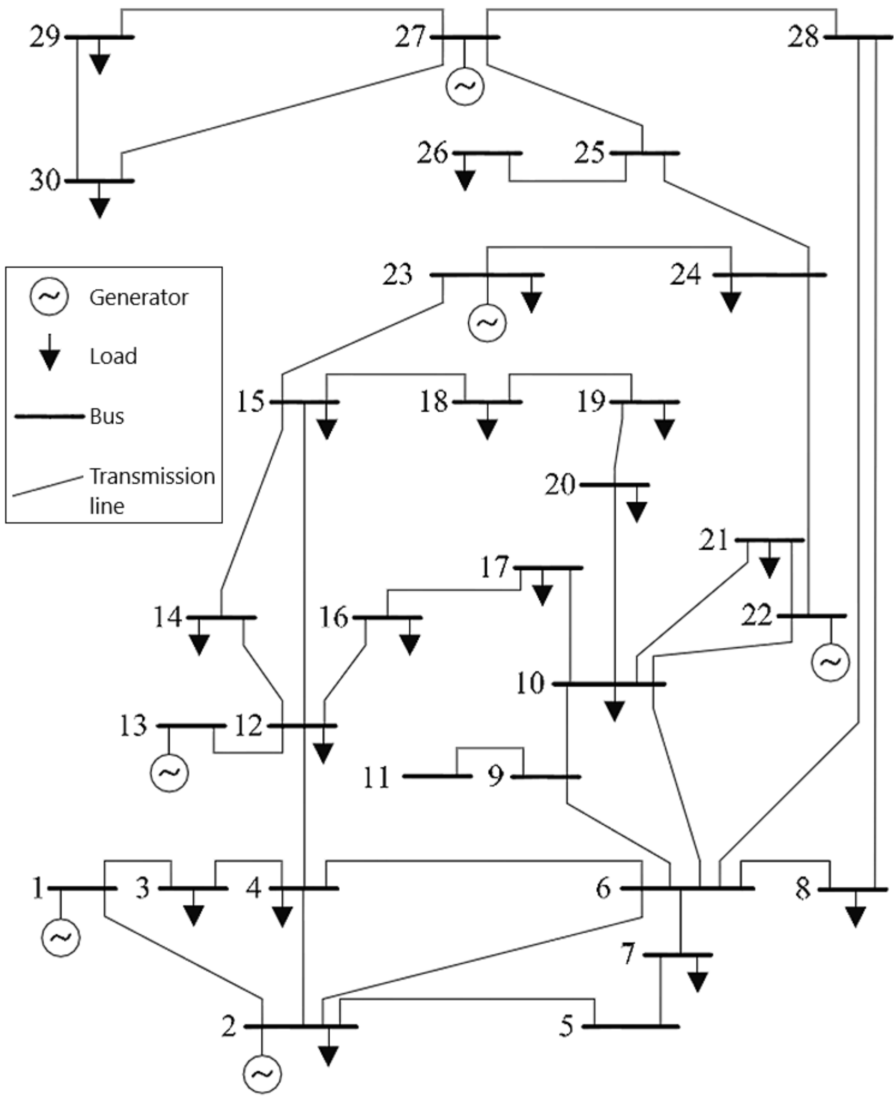

Figure 2.1: Schematic of the IEEE 30-bus test system representing its generators, loads, busses and transmission lines.

which would determine, based on weather conditions, how much of their upper generation capacity is accessible. Accordingly, the generation level would be limited above by $A_j^t \overline{K}_j$. Note that, for these technologies, $\underline{K}_j = 0$ since $\underline{K}_j \leq A_j^t \overline{K}_j$.

For every generator j in every interval t, we denote by $q_j^t \in \mathbb{R}$ the reactive power generation level whose magnitude is limited by its capacity limit $\overline{Q}_j \in \mathbb{R}$, i.e.,

$$-\overline{Q}_j \leq q_j^t \leq \overline{Q}_j^t, \tag{2.2}$$

where $\overline{Q}_j \geq 0$.

For every generator j, the difference in the active power generation level between every pair of adjacent intervals, t and $t-1$, lies within the ramping limit[3] [20], $\overline{R}_j \in \mathbb{R}$, i.e.,

$$-\overline{R}_j \leq p_j^t - p_j^{t-1} \leq \overline{R}_j \;\forall j \in \mathcal{J}, \forall t \in \mathbb{N}\backslash\{0\}, \tag{2.3}$$

where $\overline{R}_j \geq 0$ and $\overline{R}_j \to \infty$ for every generator j that does not have ramping constraints. Note that, for technologies with availability factors, $\overline{R}_j = \overline{K}_j$ since $-1 \leq A_j^t - A_j^{t-1} \leq 1$.

Every generator j has a generation cost $C_j \in \mathbb{R}$ [21], which is a function of its active power generation[4], p_j^t, such that $C_j := C_j\left(p_j^t\right)$. Naturally, C_j is non-negative, i.e., $C_j \geq 0$ and non-decreasing in p_j^t, i.e., $\partial C_j/\partial p_j^t \geq 0$. To simplify the market clearing models, we assume that C_j is convex in p_j^t, i.e., $\partial^2 C_j/\partial {p_j^t}^2 \geq 0$. Here, since C_j is non-decreasing and convex in p_j^t, it is piecewise differentiable and piecewise twice-differentiable in p_j^t, respectively, with only jump discontinuities. In order to handle the jump discontinuities and to allow the derivative of C_j with respect to p_j^t to exist everywhere, we have only considered its right-hand derivative[5] at every p_j^t without explicitly denoting it. We will follow this as a convention for all piecewise differentiable functions.

Generation of electricity by every generator j in every interval t is accompanied by environmental pollution where the amount of pollution depends upon the generation technology used [22] and the amount of active power generated [6]. Let $x_j^t \in \mathbb{R}$ denote the amount of pollution, which is a function of the active power generated, p_j^t, such that $x_j^t := x_j^t\left(p_j^t\right)$. Naturally, x_j^t is non-negative, i.e., $x_j^t \geq 0$ and non-decreasing in p_j^t, i.e., $\partial x_j^t/\partial p_j^t \geq 0$. Here, since $x_j^t \geq 0$ and non-decreasing in p_j^t, it is piecewise differentiable in p_j^t with only jump discontinuities. For simplicity, we assume that x_j^t is convex in p_j^t, i.e., $\partial^2 x_j^t/\partial {p_j^t}^2 \geq 0$ and therefore, it is piecewise twice-differentiable in p_j^t, with only jump discontinuities.

[3]For simplicity, we only model the ramping limits for the active power generation levels. A complete representation of ramping limits would also constrain the reactive power generation levels.

[4]For simplicity, we model the generation cost as a function of its active power generation. A complete representation of its cost would also include its reactive power generation.

[5]The right-hand derivative of function $g(z)$ with respect to z is defined as

$$\left.\frac{\partial g(z)}{\partial z}\right|_{+} = \lim_{h\to 0^+} \frac{g(z+h) - g(z)}{h}.$$

2.2 Busses

In this thesis, we model that a bus in a power system serves as a point of connection for loads and generators located at a given geographical location to the rest of the system as shown in Figure 2.1. Loads and generators are connected to busses either directly or if they are small, via local distribution grids[6]. Let $\mathcal{N}$ be the set of busses and n index individual busses such that $n \in \mathcal{N}$.

At every bus n, in every interval t, there exists, in general, an active power load $d_n^t \in \mathbb{R}$, which is non-negative, i.e.,

$$d_n^t \geq 0 \; \forall n \in \mathcal{N}, \forall t \in \mathbb{N}. \tag{2.4}$$

In addition, there exists, in general, a reactive power load $e_n^t \in \mathbb{R}$. For every bus n with no load, $d_n^t = e_n^t = 0 \; \forall t \in \mathbb{N}$.

The matrix $[A_{nj}]_{nj}$ can be used to describe the bus n at which each generator j is located by defining it as

$$A_{nj} = \begin{cases} 1 \text{ if } j \text{ is located at } n, \\ 0 \text{ otherwise} \end{cases} \qquad \forall n \in \mathcal{N}, j \in \mathcal{J}. \tag{2.5}$$

Accordingly, the active power injection [23] into (or the net power generated at) bus n in interval t is

$$\sum_j A_{nj} p_j^t - d_n^t \tag{2.6}$$

and the reactive power injection is

$$\sum_j A_{nj} q_j^t - e_n^t. \tag{2.7}$$

Every bus n in every interval t has a voltage phasor $v_n^t \in \mathbb{C}$ whose magnitude lies within its lower and upper limits [23], $\underline{V}_n \in \mathbb{R}$ and $\overline{V}_n \in \mathbb{R}$, respectively, i.e.,

$$\underline{V}_n \leq \left| v_n^t \right| \leq \overline{V}_n \; \forall n \in \mathcal{N}, \forall t \in \mathbb{N}, \tag{2.8}$$

where $0 \leq \underline{V}_n \leq \overline{V}_n$. In addition, every bus n has a shunt, which connects it to the ground. The shunt will have an admittance $\hat{y}_n \in \mathbb{C}$.

At every bus n, environmental pollution results in a negative externality $E_n \in \mathbb{R}$, which is a function of the total pollution at the bus, $\sum_j A_{nj} x_j^t$, such that $E_n := E_n \left(\sum_j A_{nj} x_j^t \right)$. Naturally, E_n is non-negative, i.e., $E_n \geq 0$ and non-decreasing in $\sum_j A_{nj} x_j^t$, i.e., $\partial E_n / \partial x_j^t \geq 0$. In addition, we assume that E_n is convex in $\sum_j A_{nj} x_j^t$, i.e., $\partial^2 E_n / \partial {x_j^t}^2 \geq 0$. Here, since E_n is non-decreasing and

[6]This thesis does not model distribution grids.

convex in $\sum_j A_{nj} x_j^t$, it is piecewise differentiable and piecewise twice-differentiable in $\sum_j A_{nj} x_j^t$, respectively, with only jump discontinuities.

Since the electricity market has a large number of consumers that are each very small in size, an individual consumer's influence on the market is negligible. Therefore, they are typically modelled as a continuum rather than discrete entities and are assumed to be price-takers. At every bus n in every interval t, consumers have a utility $U_n^t \in \mathbb{R}$ [24], which is a function of the active power load at the bus, d_n^t, such that $U_n^t := U_n^t\left(d_n^t\right)$. Naturally, U_n^t is non-negative, non-decreasing in d_n^t and, since consumers with higher utility will be prioritised over those with lower utility, is concave in d_n^t, i.e., $U_n^t \geq 0$, $\partial U_n^t / \partial d_n^t \geq 0$ and $\partial^2 U_n^t / \partial {d_n^t}^2 \leq 0$, respectively. Since U_n is non-decreasing and concave in d_n^t, it is piecewise differentiable and piecewise twice-differentiable in d_n^t, respectively, with only jump discontinuities.

2.3 Transmission lines

Transmission lines connect busses in the power system to each other and the lines together form the transmission network as shown in Figure 2.1. Let $\mathcal{L}$ denote the set of transmission lines and l index individual lines such that $l \in \mathcal{L}$.

The matrices $[S_{ln}]_{ln}$ and $[T_{ln}]_{ln}$ can be used to describe, for every line l, if it originates or ends, respectively, at bus n by defining them as

$$(S_{ln}, T_{ln}) = \begin{cases} (1,0) \text{ if } l \text{ originates at } n, \\ (0,1) \text{ if } l \text{ ends at } n, \\ (0,0) \text{ otherwise} \end{cases} \qquad \forall l \in \mathcal{L}, \forall n \in \mathcal{N}. \tag{2.9}$$

Every transmission line l has an admittance $y_l \in \mathbb{C}$. Based on this, we can define the bus admittance matrix[7] $[Y_{nn'}]_{nn'}$ [25] as

$$Y_{nn'} = \begin{cases} \hat{y}_n + \sum_l y_l (S_{ln} + T_{ln}) & \text{if } n = n', \\ -\sum_l y_l (S_{ln} T_{ln'} + T_{ln} S_{ln'}) & \text{otherwise.} \end{cases} \tag{2.10}$$

For every pair of busses n and n', $Y_{nn'}$ is non-zero only if $n = n'$ or if n and n' are connected with a transmission line and therefore, the bus admittance matrix, $[Y_{nn'}]$, is sparse.

Based on these quantities, the flow of power through transmission line l in interval t is determined by either

$$\sum_{nn'} S_{ln} T_{ln'} Y_{nn'}^* \left(\left| v_n^t \right|^2 - v_n^t v_{n'}^{t*} \right) \tag{2.11}$$

or

$$\sum_{nn'} T_{ln} S_{ln'} Y_{nn'}^* \left(\left| v_n^t \right|^2 - v_n^t v_{n'}^{t*} \right), \tag{2.12}$$

[7] In this thesis we will describe power flows and losses in terms of the bus admittance factors rather than the individual admittances since it is customary to do so in literature.

where the difference between the two is due to the power losses due to the resistance of the transmission lines.

The magnitude of the flow of every transmission line l in every interval t must be within its capacity limit $\overline{F}_l \in \mathbb{R}$ [26], i.e.,

$$\left| \sum_{nn'} S_{ln} T_{ln'} Y^*_{nn'} \left(\left| v^t_n \right|^2 - v^t_n v^{t*}_{n'} \right) \right| \leq \overline{F}_l \ \forall l \in \mathcal{L}, \forall t \in \mathbb{N} \tag{2.13}$$

and

$$\left| \sum_{nn'} T_{ln} S_{ln'} Y^*_{nn'} \left(\left| v^t_n \right|^2 - v^t_n v^{t*}_{n'} \right) \right| \leq \overline{F}_l \ \forall l \in \mathcal{L}, \forall t \in \mathbb{N}, \tag{2.14}$$

where $\overline{F}_l \geq 0$.

Finally, at every bus n, in every interval t, there must be power balance [27]. This allows us to express the power injected at bus n in interval t based on (2.6) and (2.7) and based on the bus admittance matrix as

$$\sum_j A_{nj} \left(p^t_j + \jmath q^t_n \right) - d^t_n - \jmath e^t_n = v^t_n \sum_{n'} Y^*_{nn'} v^{t*}_{n'} \ \forall n \in \mathcal{N}, \forall t \in \mathbb{N}. \tag{2.15}$$

Here, in every interval t, the sum of the right hand side over all busses, $\mathcal{N}$, contains the power flows through all transmission lines in both directions, which cancel each other out such that the resultant is the sum of losses. This resultant is also naturally equal to the net power injected into the system, which is the sum of the left hand side over all busses, $\mathcal{N}$.

The set of constraints that have been laid out so far comprise the alternating current (AC) power flow model [26]. However, this model is non-linear as can be seen in constraints (2.13) and (2.14), making it difficult to consider exactly in market clearing models. Therefore, often, a linear approximation of the AC power flow model, the direct current (DC) power flow model, is used instead, which is described in the following section.

2.4 DC power flow approximation

The DC power flow model makes the following assumptions [23]:

1. In every interval t, the magnitude of the voltage at every bus n is the same, i.e.,
$$\left| v^t_n \right| = 1 \ \forall n \in \mathcal{N}, \forall t \in \mathbb{N} \tag{2.16}$$
in the per-unit system [28].

2. In every interval t, the phase angle of the voltage between every pair of busses n and n' is small such that
$$\sin \left(\angle v^t_n - \angle v^t_{n'} \right) \approx \angle v^t_n - \angle v^t_{n'} \ \forall n \in \mathcal{N}, \forall n' \in \mathcal{N}, \forall t \in \mathbb{N}. \tag{2.17}$$

3. For every transmission line l, the resistance is negligible compared to the reactance such that
$$\mathrm{Re}(Y_{nn'}) \approx 0. \tag{2.18}$$

Due to assumptions 1 and 2, the reactive power injection at every bus can be determined based only on the active power injection at every bus and therefore, constraints in (2.2) are ignored. Also, due to assumption 3, the voltage magnitude constraints in (2.8) are implicitly satisfied.

In addition, based on all the assumptions above, the real power flows through transmission line l in interval t from (2.11) and (2.12) are both equal in magnitude and can be simplified to

$$\sum_{nn'} S_{ln} T_{ln'} \mathrm{Im}(Y_{nn'}) \left(\angle v_n^t - \angle v_{n'}^t\right) = -\sum_{nn'} T_{ln} S_{ln'} \mathrm{Im}(Y_{nn'}) \left(\angle v_n^t - \angle v_{n'}^t\right). \tag{2.19}$$

The terms above can be consolidated into the power transfer distribution factor (PTDF) matrix $[H_{ln}]_{ln}$ [23], which is defined as

$$H = S\,\mathrm{Im}(Y)T^T(S-T)((S-T)^T S\,\mathrm{Im}(Y)T(S-T))^{-1}, \tag{2.20}$$

which is dense, unlike the bus admittance matrix, $[Y_{nn'}]_{nn'}$. Using the PTDF matrix, the flow through every line l can be expressed in terms of the real power injection from (2.6) at all busses, $\mathcal{N}$, in every interval t as

$$\sum_n H_{ln} \left(\sum_j A_{nj} p_j^t - d_n^t\right). \tag{2.21}$$

Based on the PTDF matrix, the capacity limit on the real power flow of transmission line l in interval t [26] takes the form

$$\left|\sum_n H_{ln} \left(\sum_j A_{nj} p_j^t - d_n^t\right)\right| \leq \overline{F}_l \;\forall l \in \mathcal{L}, \forall t \in \mathbb{N}. \tag{2.22}$$

Finally, based on assumption 3, in every interval t,

$$\mathrm{Re}\left(\sum_n v_n^t \sum_{n'} Y_{nn'}^* v_{n'}^{t*}\right) = 0 \;\forall t \in \mathbb{N} \tag{2.23}$$

Therefore, given the location of all generators from (2.5), for every interval t, the power balance constraints in (2.15) can be simplified to the single constraint [27],

$$\sum_j p_j^t = \sum_n d_n^t \;\forall t \in \mathbb{N}. \tag{2.24}$$

2.5 Producers

Unlike consumers, producers in the electricity market are few in number and may each employ multiple large generators [29], such that they form an oligopoly. Let $\mathcal{I}$ denote the set of producers and i index individual producers such that $i \in \mathcal{I}$. Every producer i, in general, employs multiple generators at multiple busses. Let $\mathcal{J}_i$ denote the set of generators operated by producer i. Every generator j will be operated by a single producer such that $\bigcup_i \mathcal{J}_i = \mathcal{J}$ and $\mathcal{J}_i \cap \mathcal{J}_{i'} = \emptyset$ if $i \neq i'$.

Chapter **3**

Day-ahead market

The goal of the day-ahead market is to maximise the economic welfare created when electricity is exchanged from producers to the consumers [12]. Therefore, the day-ahead market carries out a *competitive market clearing.* The following sections discuss the competitive market clearing and problems associated with it.

3.1 Competitive market clearing

The economic welfare created by exchange of a good is the difference between the utility created by consumption of a good and the cost of producing that good [21]. For the electricity market, in every interval t, the economic welfare is the sum of the consumer utilities at all busses, $\mathcal{N}$ less the sum of generation costs of all generators, $\mathcal{G}$ such that the maximum economic welfare is

$$\max_{\left(p_j^t, d_n^t | j \in \mathcal{J}, n \in \mathcal{N}\right)} \left(\sum_n U_n^t \left(d_n^t\right) - \sum_j C_j \left(q_j^t\right) \right). \tag{3.1}$$

In order to carry out a competitive market clearing, producers must declare their costs and consumers must declare their utilities. Based on these declarations, in every interval t, the market operator solves the economic welfare maximisation in (3.1), subject to constraints (2.1), (2.4), (2.22) and (2.24). Here, we have assumed the DC power flow model described in Section 2.4. This maximisation yields a dispatch instruction $\left(p_j^t, d_n^t | j \in \mathcal{J}, n \in \mathcal{N}\right)$, i.e., the active power generation levels of every generator j and demand at every bus n such that the generators will follow a least-cost dispatch and the demand at busses with the higher utilities will be satisfied. The price would, in general, be different at different busses [30], and would be the point of intersection of the marginal generation cost with the marginal consumer utility.

Observe that the maximisation is conducted for a single interval at a time and therefore, ramping constraints in (2.3) cannot be incorporated. The authors in [31] argue that ramping constraints are internalised by producers and therefore, do not need to be considered explicitly. Following a similar reasoning, most market operators globally do not explicitly consider ramping constraints while clearing the day-ahead market [32].

3.2 Pollution externality

One problem with competitive market clearing is that it maximises the economic welfare rather than the social welfare. The social welfare created by exchange of a good is the aggregate of the economic welfare and any externalities due to the exchange. For the electricity market, in every interval t, the social welfare is the economic welfare less the negative externality due to pollution at all busses $\mathcal{N}$, such that the maximum social welfare is

$$\max_{\left(p_j^t, d_n^t \mid j \in \mathcal{J}, n \in \mathcal{N}\right)} \left(\sum_n \left(U_n^t \left(d_n^t\right) - E_n \left(\sum_j A_{nj} x_n^t \right) \right) - \sum_j C_j \left(q_j^t\right) \right). \tag{3.2}$$

Figure 3.1 compares the competitive market clearing solution with the social welfare maximising solution for a simple system with one bus and one generator. The figure illustrates the marginal consumer utility, the marginal generation cost and the marginal total cost, where the total cost is the sum of the generation cost and the pollution externality. The competitive market clearing solution is obtained from the intersection of the marginal utility with the marginal generation cost, whereas the social welfare maximising solution is obtained from its intersection with the marginal total cost. The figure illustrates that when the externality is accounted for, the generation level is lower. The solid shaded region illustrates the maximum social welfare. However, for the competitive solution, in addition to the maximum social welfare, there is a striped region of *negative social welfare* that will be realised where the marginal total cost exceeds the marginal consumer utility. Therefore, the competitive solution results in lower social welfare.

Producers and consumers in electricity markets are profit-maximising participants. In order for the market to robustly achieve its sustainability goals, these goals need to be incorporated into the profit maximisation goals of these individual participants. Accordingly, the European Commission prescribes using market mechanisms to reduce carbon emissions from power systems [33]. Since it is the generation of electricity that is the natural target of sustainability actions, these market mechanisms must target producers.

The least-cost dispatch resulting from the competitive market clearing is based only on the generation cost. However, in order to prioritise low-polluting generation technologies, the pollution externality must be considered in the least-cost dispatch, too. Since the competitive market clearing does not consider the true cost of generation, it lacks the incentive to use generation resources with low pollution levels.

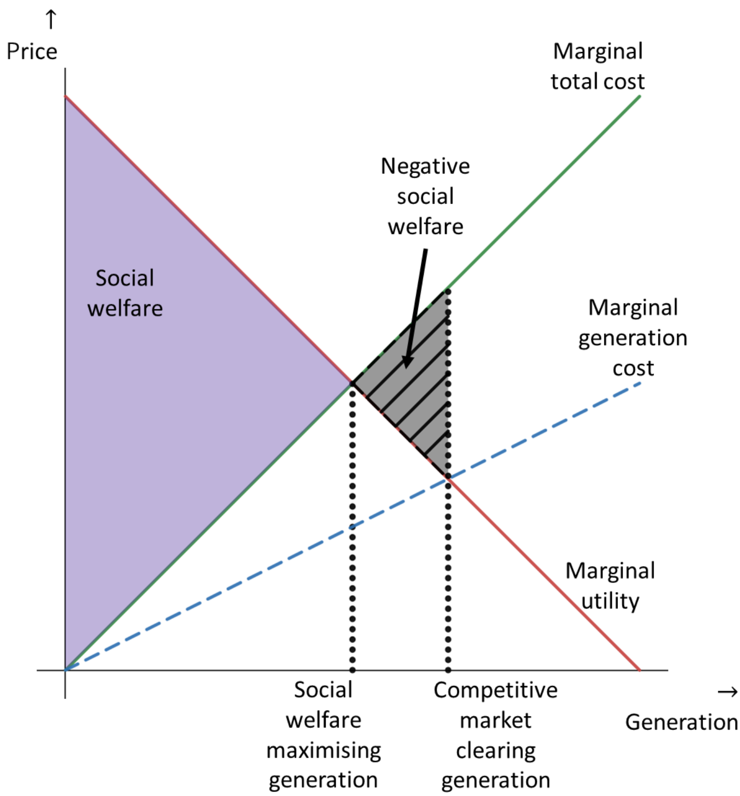

Figure 3.1: Illustration of the competitive market clearing vs. the social welfare maximising solution.

In the economics literature, Pigouvian taxes on producers [34] have been proposed to manage negative externalities. The amount of tax on a producer would be equal to their marginal contribution to the externality. The carbon tax [35] is a type of Pigouvian tax which is often employed as a market mechanism to manage pollution in different systems.

Carbon caps [36, 37] are another solution to manage pollution. However, they form an ad-hoc measure [38], which does not properly represent the pollution externality. This is because they simply limit the total amount of pollution and hence the generation based on time-average values of the associated costs rather than trade off the cost of pollution damage with the social welfare created due to power generation. Also, they are levied on producers in electricity markets based on their time-average market shares with respect to the amount of power generated, even though there is no direct relationship between pollution levels and generation levels.

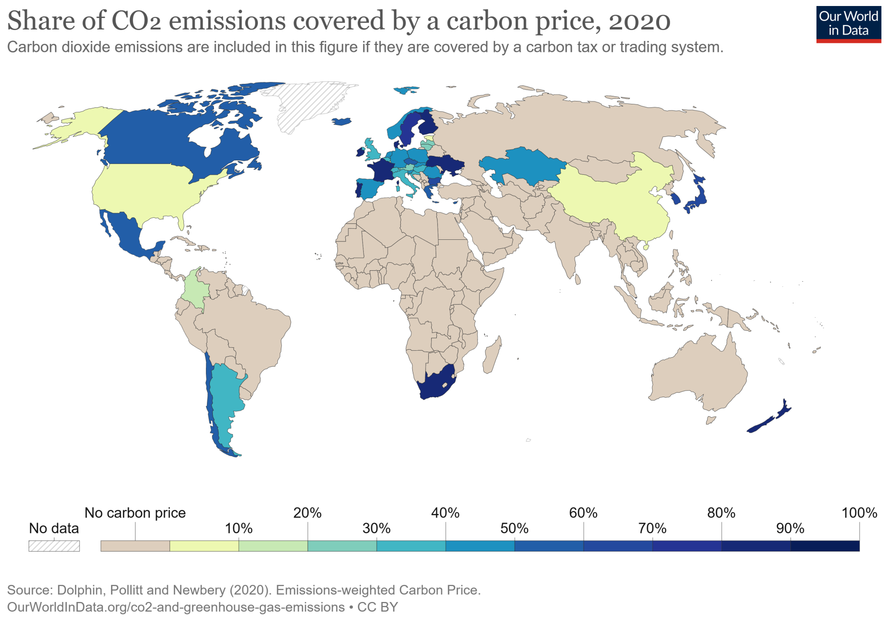

Figure 3.2: Country-wise share of pollution managed using carbon taxes or carbon allowances as of 2020.

On the other hand, carbon taxes properly represent the pollution externality and depend only upon the amount of pollution generated by each producer.

Whilst carbon taxes and allowances have extensively been discussed in literature, globally, only a handful of countries have adopted carbon taxes to manage pollution, as indicated in Figure 3.2, and even the ones that do, only manage a small fraction of their pollution this way. Also, carbon taxes applied to electricity generators are not handled by the day-ahead market operator. Rather, they are imposed by a separate entity for all sectors including power systems outside the competitive market clearing framework. Therefore, the competitive market clearing would still consider only the generation costs.

Consequently, countermeasures against pollution within day-ahead markets are realised in an ad-hoc manner, e.g., sometimes market operators have to go against competitive market clearing and dispatch low-polluting wind or solar generation units [39] or, in systems with large hydro plants and reservoirs, to dispatch hydro units [40]. Therefore, from an administrative point of view, it is possible for market operators to handle externalities as part of market clearing. For the reasons above and because power systems are responsible for a large share of emissions [6], it is worthwhile doing so.

However, the solution to this problem is not as straightforward as including the externality in the generation price. While the price is a function of the total generation level, the externality is a function of the total pollution level, with no direct relationship between the two. Rather, the amount of pollution created depends heavily upon the generation technology.

Since the market operator may suffer from information asymmetry about producers' internal operations it may be unable to track the pollution level per individual generating unit and therefore, cannot include it in the price. Simply including the externality in the price is also a problem since it may incentivise producers to increase the pollution levels to increase prices.

The authors in [41] also modelled pollution in general markets separately from production as a decreasing function of a continuous pollution abatement parameter such that the cost of production increases with this parameter. However, this approach may not be suited to electricity markets for two reasons. First, for electricity markets, the dependence of the amount of pollution on abatement efforts is negligible compared to the choice of generation technology. Generation technologies cannot be effectively represented by a continuous parameter. Second, a single producer may, in general, control several generation units, each with their own generation technology. These problems are overcome in Papers C [42] and D [43]. In Papers C and D, we explicitly compare the economic welfare maximisation to the social welfare maximisation in electricity markets and show that Pigouvian taxes based on each producer's total pollution levels may be used to manage pollution in a manner that is integrated into the competitive market clearing process, even under the assumption that market operators face information asymmetry.

3.3 Strategic behaviour

Another problem with competitive market clearing is that producers can behave strategically, where they can limit their generation levels to increase prices. Although they produce less, the increase in prices may increase their profits.

At every bus n, in every interval t, the optimality condition of the competitive market clearing results in a price[1] P_n^t as

$$P_n^t\left(\sum_j A_{nj}p_j^t\right) = \frac{\partial C_j}{\partial p_j^t} + \omega_j^t = \frac{\partial U_n^t}{\partial d_n^t}\ \forall n \in \mathcal{N}, \forall j \in \mathcal{J}, A_{nj} = 1, \forall t \in \mathbb{N}, \tag{3.3}$$

where ω_j^t is the sum of all Karush-Kunh-Tucker (KKT) multipliers from all constraints on p_j^t resulting from the competitive market clearing, (3.1), subject to constraints (2.1), (2.4), (2.22) and (2.24).

[1] In general, every bus will have a different price if any transmission line is congested. However, in practice, for computational efficiency, some transmission line constraints are ignored and the pricing is zonal rather than nodal.

The profit of a producer is their revenue less the cost. For every producer i, in every interval t, the maximum profit is

$$\max_{(p_j \mid j \in \mathcal{J}_i)} \left(\sum_n P_n^t \left(\sum_j A_{nj} p_j^t \right) \sum_{j \in \mathcal{J}_i} A_{nj} p_j^t - \sum_{j \in \mathcal{J}_i} C_j \left(p_j^t \right) \right), \tag{3.4}$$

subject to constraints (2.1). This results in the optimality condition

$$P_n^t A_{nj} = \frac{\partial C_j}{\partial p_j^t} + \rho_j^t + \frac{\partial P_n^t}{\partial p_j^t} \sum_{j \in \mathcal{J}_i} A_{nj} p_j^t \ \forall j \in \mathcal{J}, \forall t \in \mathbb{N}, \tag{3.5}$$

where ρ_j^t is the sum of the KKT multipliers on p_j^t. Therefore, to maximise profits, producers declare a false cost for which the marginal cost is the RHS above such that the price is set accordingly. This optimality condition results in different lower generation levels compared to (3.3).

Figure 3.3 compares the competitive market clearing solution with the profit maximising solution for a simple system with one bus and one generator. The figure illustrates the marginal consumer utility, the marginal generation cost and the marginal declared generation cost, where the declared cost is false, to maximise profits. As before, the competitive market clearing solution is obtained from the intersection of the marginal utility with the marginal generation cost, whereas the profit maximising solution is obtained from its intersection with the marginal declared cost. Therefore, the generation level is lower and price is higher. The solid shaded region illustrates the economic welfare. Compared to the competitive solution, the profit maximising solution is missing a region of economic welfare, which is striped, that is not realised due to the false declared cost. Therefore, the profit maximising solution results in lower economic welfare. The producer's profit is illustrated by the part of the solid shaded region below the price. We can see that the profit increases even though social welfare decreases due to the false cost declaration.

Producers' strategic behaviour [16] has been extensively studied [44–48] and has been shown to exist particularly in electricity markets [49]. In the economics literature, several methods have been proposed to mitigate strategic behaviour. Loeb and Magat proposed a general market mechanism [50] that provides as a subsidy the consumer surplus to a monopolist producer, which would incentivise them to maximise the total social welfare and is therefore, incentive compatible. Accordingly, it analytically solves the problem without burdening the regulator with gaining information about the producer's cost. It was shown in [51], for electricity markets in particular, that the consumer utility at a bus can be determined from the prices at that bus, making it possible to implement the mechanism in [50]. A problem with the scheme proposed in [50] is that granting the entire consumer surplus as a subsidy causes funding problems for the regulator. The Incremental Surplus Subsidy (ISS) [52] alleviates this problem by only providing the increase in consumer surplus as compared to the previous regulatory period. Since ISS incentivises *increases*

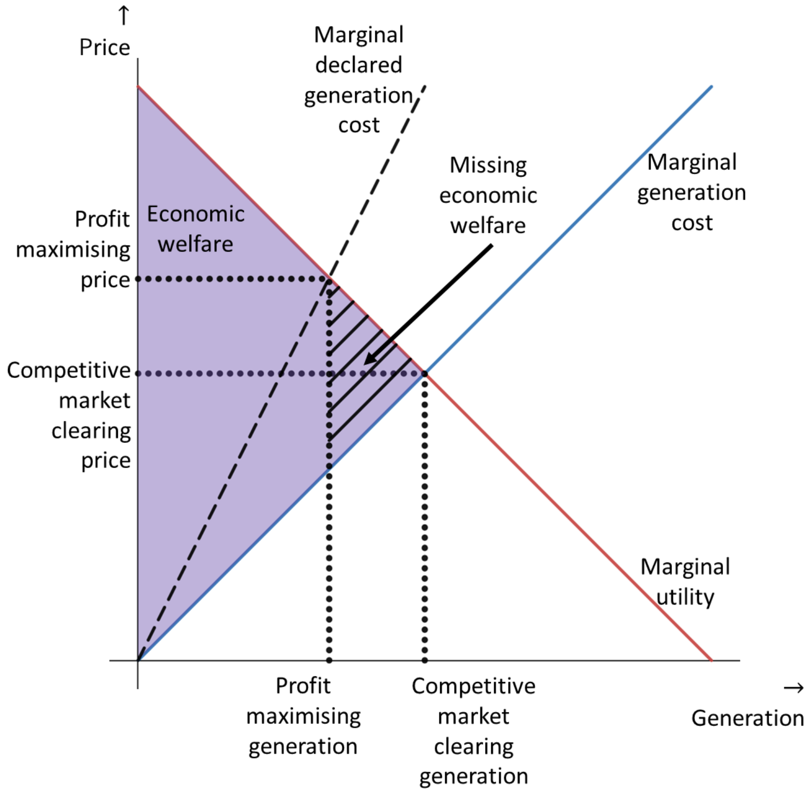

Figure 3.3: Illustration of the competitive market clearing vs. the profit maximising solution.

in consumer surplus, its use lies mostly in incentivising investments that result in permanent increases rather than mitigating strategic production. However, ISS is prone to challenges. Producers may decrease production under expectations that ISS would be implemented so that they may receive a larger subsidy. Also, regulators would have to be careful about mergers, acquisitions and divestitures by not taxing a producer that sold its assets for decreasing consumer surplus but also not subsidising assets that were simply transferred from one producer to another.

Although there are several proposals in the economics literature to grant producers the difference in economic welfare and their profits, the use of price caps have been proposed [53] to mitigate strategic behaviour in electricity markets. They are widely adopted in electricity markets around the world [54, 55] since they are less information intensive in the sense that the market operator does not need to monitor the internal operations of every producer. However, price caps have the following drawback. Any efficient electricity market must have rare instances of load-shedding [56]. It is in these instances that producers' profit, even if they employ cheap energy sources, would be high enough to profit enough to recover their investment costs since the price would be set by the high marginal utility rather than the low marginal cost. Note that this is not an instance of strategic behaviour; even the socially optimal solution would have this result. However, with price caps, which would typically be much lower than the marginal utility, this would not be possible, exacerbating the problem.

In Paper C [42], we propose to grant a subsidy to producers based on their marginal contribution to the consumer surplus. Accordingly, we avoid the issues associated with price caps. Also, since we only grant the marginal consumer surplus, the funding burden on the market operator is low. In addition, in our scheme, the surplus in a single regulatory period is independent of the outcomes in previous periods, the problems of ISS are overcome. We also explicitly model nodal pricing and that the price at one bus can depend upon the generation at another.

Chapter 4

Real-time market

The dispatch determined by the day-ahead market is based on 12 to 36-hour old forecasts of net demand, i.e., the demand less the renewable generation [57]. Therefore, in the real-time market [13], there needs to be a re-dispatch based on updated forecasts of the net demand. In addition, the day-ahead market does not contain any measures to ensure a secure operation of the power system. Therefore, to ensure secure operation, typically, security constraints are included in the real-time market [13].

Since the power system is a critical infrastructure, it is important to ensure its security. Due to the interconnected nature of individual components of the power system, a failure in any component may cause other components to operate beyond their limits, which, in turn, may push other components beyond their limits. Therefore, power systems are at a risk of cascading failures.

Security in power systems entails ensuring that components operate within their limits even in the event of contingencies and is implemented following the $N-k$ contingency criterion [58]. The $N-k$ contingency criterion ensures that, even if a sequence of k contingencies were to occur, where $k \in \mathbb{N}$, the rest of the power system can maintain a stable operation where all components operate within their limits. Security would take the form of constraints on the generation dispatch.

Typically, power systems are operated under the $N-1$ contingency criterion. However, several markets have adopted the $N-k$ contingency criterion for $k > 1$ in order to improve security. The government of the state of New South Wales in Australia has imposed an $N-2$ planning standard in the Sydney region transmission network [59] and TenneT in Netherlands considers the $N-2$ contingency criterion as a benchmark to test its transmission systems [60].

The sections that follow list the types of contingencies considered in this thesis, different ways in which security may be enforced and model the competitive market clearing in the real-time market.

4.1 Types of contingencies

Let $\mathcal{C}$ denote the set of contingencies and c index individual contingencies such that $c \in \mathcal{C}$. Let u denote the interval in which contingency c would take place such that $u \in \mathbb{N}, u > 0$.

Contingencies could take place in any component of the power system, e.g., a transmission line, a generator, a transformer or a shunt. This thesis considers contingencies in transmission lines and generators where $\mathcal{C}_{\mathcal{L}}$ and $\mathcal{C}_{\mathcal{J}}$ denote the sets of transmission line and generator contingencies, respectively, such that $\mathcal{C}_{\mathcal{L}} \subseteq \mathcal{L}$, $\mathcal{C}_{\mathcal{J}} \subseteq \mathcal{J}$ and $\mathcal{C}_{\mathcal{L}} \cup \mathcal{C}_{\mathcal{J}} \subseteq \mathcal{C}$.

The $N-k$ contingency criterion, in general, requires security against a sequence of multiple contingencies, $(c_1, \ldots, c_k)$ where the sequence could contain contingencies of different types such that $c_1, \ldots, c_k \in \mathcal{C}_{\mathcal{L}} \cup \mathcal{C}_{\mathcal{J}}$. These contingencies would take place in intervals $(u_1, \ldots, u_k)$, respectively, where $u_1 \leq \ldots \leq u_k$.

The state of the power system in every interval t is determined by the set of voltage phasors at all busses, $\mathcal{N}$, and active and reactive power generation levels at all generators, $\mathcal{J}$, $\left(v_n^t, p_j^t, q_j^t | n \in \mathcal{N}, j \in \mathcal{J}\right)$. Following a contingency, in general, the state of the system may change. Let the addition of superscript (c, u) to any quantity denote the post-contingency value of that quantity, i.e., the value after interval u, had contingency c taken place in interval u. E.g., $p_j^{t(c_1,u_1)(c_2,u_2)}$ is the active power generation of generator j in interval t after the sequence of contingencies c_1 and c_2 has occurred in intervals u_1 and u_2, respectively, where $t > u_2$.

Transmission line contingencies

We model transmission line contingency c as the disconnection of transmission line $l = c$ [23]. Unlike other networks such as communication networks, where the flows through edges are chosen as required, the power flows through the network of transmission lines are determined from the bus injections using Kirchoff's laws from (2.11) and (2.12) in the AC power flow model, and (2.21) in the DC power flow model. Therefore, following every transmission line contingency, the power flows would be redistributed through the remaining transmission lines, which, if not kept within limits, may overload other lines causing them to overheat and disconnect in turn, leading to a cascade of failures [61]. Therefore, it is important to ensure that, in every interval t, the post-contingency state of the system $\left(v_n^{t(c,u)}, p_j^{t(c,u)}, q_j^{t(c,u)} | n \in \mathcal{N}, j \in \mathcal{J}\right)$ satisfies the power system constraints.

Since the power flows are redistributed through the remaining transmission lines, in addition to the state of the system, some parameters may also change. Since the change in parameters would be independent of the interval u in which the contingency would take place, the superscript (c) is used to denote the parameter under contingency c.

Under the AC power flow model, if transmission line $l = c$ is disconnected in interval u, the admittance of the line becomes zero, i.e., $y_l^{(c)} = 0$ and therefore, the terms in the bus admittance matrix that depend upon it will change, i.e., $Y^{(c)}_{nn'} = Y^{(c)}_{n'n} = 0$, $Y^{(c)}_{nn} \neq Y_{nn}$ and $Y^{(c)}_{n'n'} \neq Y_{n'n'}$, where n and n' are the busses to which line l is connected such that $S_{ln} = T_{ln'} = 1$. Accordingly, the state under contingency c in every interval $t > u$ would satisfy constraints (2.1) to (2.4), (2.8) and (2.13) to (2.15) defined in the previous chapter with the same parameters except the following, which contain the changed parameters.

- The transmission line flow limits for line l when modified from (2.13) and (2.14) would be implicitly satisfied

- The power balance constraints for busses n and n', which would be modified from (2.15) to

$$\sum_j A_{nj} \left(p_j^{t(c,u)} + \jmath q_n^{t(c,u)} \right) - d_n^t - \jmath e_n^t = v_n^{t(c,u)} \sum_{n''} Y^{(c)*}_{nn''} v^{t(c,u)*}_{nn''}$$
$$\forall c \in \mathcal{C}_{\mathcal{L}}, \forall l \in \mathcal{L}, l = c, \forall n \in \mathcal{N}, S_{ln} = 1, \forall u, t \in \mathbb{N}, t > u \quad (4.1)$$

  and

$$\sum_j A_{n'j} \left(p_j^{t(c,u)} + \jmath q_{n'}^{t(c,u)} \right) - d_{n'}^t - \jmath e_{n'}^t = v_{n'}^{t(c,u)} \sum_{n''} Y^{(c)*}_{n'n''} v^{t(c,u)*}_{nn''}$$
$$\forall c \in \mathcal{C}_{\mathcal{L}}, \forall l \in \mathcal{L}, l = c, \forall n' \in \mathcal{N}, T_{ln'} = 1, \forall u, t \in \mathbb{N}, t > u, \quad (4.2)$$

  respectively

In case of a sequence of contingencies that contains multiple transmission line contingencies, the constraints above would be modified for each contingent transmission line.

Under the DC power flow model, the state under contingency c in every interval $t > u$ would satisfy all the constraints (2.1), (2.3) and (2.4) defined in the previous chapter with the same parameters. The following constraints would change.

- Following a transmission line contingency c in interval u, the PTDFs from (2.20) for every other line l and bus n would change [23]. This is because, unlike the bus admittance factors, which contain the admittance of individual lines, PTDFs map the power flows though all lines, $\mathcal{L}$, given the injections at all busses, $\mathcal{N}$. Accordingly, for every transmission l, in every interval $t > u$, the transmission line flow limits modified from (2.22) are

$$\left| \sum_n H^{(c)}_{ln} \left(\sum_j A_{nj} p_j^{t(c,u)} - d_n^t \right) \right| \leq F_l \ \forall c \in \mathcal{C}_{\mathcal{L}}, \forall l \in \mathcal{L}, l \neq c, \forall u, t \in \mathbb{N}, t > u. \quad (4.3)$$

- Following a transmission line contingency, the system may split into islands, i.e. components that are disconnected from each other. Following a sequence of contingencies $(c_1, \dots, c_k)$ that contains multiple transmission line contingencies, say $m^{(c_1,\dots,c_k)}$, where $m^{(c_1,\dots,c_k)} \in \mathbb{N}, m^{(c_1,\dots,c_k)} \leq k$, there may be up to $m^{(c_1,\dots,c_k)}+1$ islands. The power balance constraint from (2.15) would have to be satisfied for each island individually. Let s index individual islands such that $s \in \mathbb{N}, s < m^{(c_1,\dots,c_k)}$ and let the set of busses in each island following the contingency sequence be denoted by $\left(\mathcal{N}_s^{(c_1,\dots,c_k)} | s \in \mathbb{N}, s \leq m^{(c_1,\dots,c_k)} + 1\right)$, where $\bigcup \mathcal{N}_s^{(c_1,\dots,c_k)} = \mathcal{N}$ and $\mathcal{N}_s^{(c_1,\dots,c_k)} \cap \mathcal{N}_{s'}^{(c_1,\dots,c_k)} = \emptyset$ if $s \neq s'$. Following a contingency c in interval u, the power balance constraint in every interval $t > u$ would need to be modified from (2.24) to

$$\sum_{n \in \mathcal{N}_s^{(c)}} \sum_j A_{nj} p_j^{t(c,u)} = \sum_{n \in \mathcal{N}_s^{(c)}} d_n^t \ \forall c \in \mathcal{C}_{\mathcal{L}}, \forall s, u, t \in \mathbb{N}, s \leq m^{(c)} + 1, t > u. \tag{4.4}$$

  Here, under a single contingency c, $m^{(c)} + 1 \in \{1, 2\}$ depending upon whether the transmission line created islands or not.

Generator contingencies

In this thesis, without loss of generality, a generator contingency c is modelled as the complete shutdown[1] of generator $j = c$ [23]. The shutdown of generator $j = c$ in interval u means that the generator does not producer any active or reactive power in every interval $t > u$, i.e.,

$$p_j^{t(c,u)} = 0 \ \forall c \in \mathcal{C}_{\mathcal{J}}, \forall j \in \mathcal{J}, j = c, \forall u, t \in \mathbb{N}, t > u \tag{4.5}$$

and

$$q_j^{t(c,u)} = 0 \ \forall c \in \mathcal{C}_{\mathcal{J}}, \forall j \in \mathcal{J}, j = c, \forall u, t \in \mathbb{N}, t > u. \tag{4.6}$$

Immediately following the shutdown of a generator, the kinetic energy stored in spinning parts of other generators is used to compensate for the generation shortfall, resulting in a decrease in the frequency of the entire system. This may, in turn, cause other generators to shutdown, leading to a cascade of failures [62]. Therefore, it is important to ensure that, in every interval t, the post-contingency state of the system $\left(v_n^{t(c,u)}, p_j^{t(c,u)}, q_j^{t(c,u)} | n \in \mathcal{N}, j \in \mathcal{J}\right)$ satisfies the power system constraints. In case of a sequence of contingencies that contains multiple generator contingencies, the constraints above would be modified for each contingent generator.

[1]For simplicity, we only model shutdowns of entire generation units even though generators may also face contingencies where a fraction of their capacity faces a shutdown. However, this is without loss of generality since security against the complete shutdown of a generator would implicitly ensure security against a partial shutdown. Also, if a generator is only at a risk of a partial shutdown, it can be modelled as two units, where one is considered for contingencies and is not.

4.2 Types of security against contingencies

There are two main classes of approaches to managing contingencies, preventive security and corrective security [63]. Preventive security against a contingency ensures that the state of the system does not need to change in response to the contingency whereas corrective security presumes that the state will change following a contingency in order to attain a stable operating point. The sections that follow describe these classes of security in detail.

Preventive security

Let $\mathcal{C}_{\mathcal{P}}$ be the set of contingencies secured using preventive security. Preventive security against contingency c requires that the state of the system does not change following the contingency, i.e.,

$$\left(v_n^{t(c,u)}, p_j^{t(c,u)}, q_j^{t(c,u)} | n \in \mathcal{N}, j \in \mathcal{J}\right) = \left(v_n^t, p_j^t, q_j^t | n \in \mathcal{N}, j \in \mathcal{J}\right)$$
$$\forall c \in \mathcal{C}_{\mathcal{P}}, \forall u, t \in \mathbb{N}, t > u. \quad (4.7)$$

For this to be possible, the pre-contingency state of the system $\left(v_n^t, p_j^t, q_j^t | n \in \mathcal{N}, j \in \mathcal{J}\right)$ must simultaneously satisfy the pre-contingency and post-contingency constraints.

Corrective security

Let $\mathcal{C}_{\mathcal{C}}$ be the set of contingencies secured using corrective security. Unlike preventive security, corrective security against contingency c allows the state of the system to deviate following a contingency. Instead the following things happen in the aftermath of the contingency. Immediately after the contingency, short-term generation reserves compensate for the contingency's effects. E.g., following a generator contingency, reserve generators would make up for the shortfall in generation by increasing their generation levels.

Short-term reserves may only be used for a predetermined amount of time after which the other generators must change their generation levels to satisfy the post-contingency constraints. Without loss of generality, we discretise time such that one dispatch interval is equal to this predetermined amount of time[2].

For every generator j that is not contingent $j \neq c$, the difference between post-contingency active power generations levels in interval $t = u + 1$ and the pre-contingency levels in interval u must lie within its ramping limits, i.e.,

$$-\overline{R}_j \leq p_j^{t(c,u)} - p_j^{t-1} \leq \overline{R}_j \; \forall c \in \mathcal{C}_{\mathcal{C}}, \forall j \in \mathcal{J}, j \neq c, \forall u, t \in \mathbb{N}, t = u + 1. \quad (4.8)$$

[2] In general, any number of dispatch intervals, whole or fractional, could be equal to this predetermined amount of time. The formulations developed can be simply generalised to account for this by including ramping constraints corresponding to how time is discretised such that the results developed in the thesis would apply.

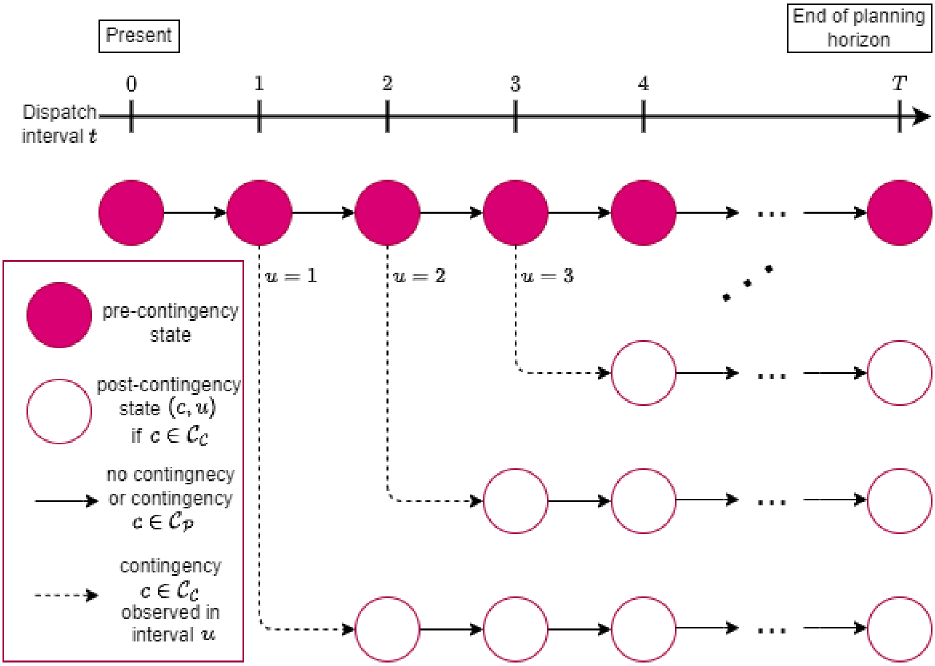

Figure 4.1: Illustration of the dispatch following a contingency under corrective security.

In addition, the difference in generator j's active power generation levels between adjacent intervals post-contingency must also lie within its ramping limits, i.e.,

$$-\overline{R}_j \leq p_j^{t(c,u)} - p_j^{t-1(c,u)} \leq \overline{R}_j \; \forall c \in \mathcal{C}_{\mathcal{C}}, \forall j \in \mathcal{J}, j \neq c, \forall u, t \in \mathbb{N}, t > u + 1. \quad (4.9)$$

Figure 4.1 illustrates our model of operation under corrective security. Every column corresponds to a dispatch interval t. The first row corresponds to the pre-contingency states where the pre-contingency state in each interval t is represented by a shaded circle. If no contingency or a contingency with preventive security would take place, the dispatch would follow the first row. The solid arrow between each adjacent pair of circles represents the ramping constraints (2.3) between them. Every row after the first corresponds to a contingency interval u, where the rows are in decreasing order of u. If a contingency would take place in interval u, the system would transition from the pre-contingency state to the post-contingency state in that interval. The dashed arrow between the states represents the ramping constraints (4.8) that would apply to the dispatch immediately before and immediately after the contingency. Thereafter, the system would remain in the post-contingency state such that the post-contingency state in each interval $t > u$ is represented by an empty circle. The solid arrow between each adjacent pair of circles represents the ramping constraints (4.9) between their corresponding dispatches.

Consider, in general, a sequence of multiple contingencies secured using corrective security $(c_1, \ldots, c_v)$ where $v \in \mathbb{N}, v > 0$ which would take place in intervals $(u_1, \ldots, u_v)$, respectively, where $u_1 \leq \ldots \leq u_r < u_{r+1} = \ldots = u_v$, where $r \in \mathbb{N}$, i.e., the $r+1$-th to v-th contingencies in the sequence take place in the same interval strictly after the r-th contingency. In this case, the constraint (4.8) can be generalised to

$$
\begin{aligned}
-\overline{R}_j \leq p_j^{t(c_1,u_1)\ldots(c_v,u_v)} - p_j^{t-1(c_1,u_1)\ldots(c_r,u_r)} \leq \overline{R}_j \\
\forall v, r, u, t \in \mathbb{N}, v \leq k, \forall c_1, \ldots, c_v \in \mathcal{C}_{\mathcal{C}}, \forall j \in \mathcal{J}, j \notin \{c_1, \ldots, c_v\}, r < v, \\
u_1 \leq \ldots \leq u_r < u_{r+1} = \ldots = u_v, t = u_v + 1. \quad (4.10)
\end{aligned}
$$

Here, k is be the maximum number of contingencies that would considered simultaneously under the $N-k$ contingency criterion.

Comparison of preventive and corrective security

The advantages of preventive security over corrective security are as follows.

- Preventive security can be incorporated into single-interval formulations. Corrective security, on the other hand, requires ramping constraints to be satisfied and therefore, must consider at least two intervals.

- Preventive security is computationally less intensive than corrective security. This is because corrective security requires a different post-contingency state to be defined for each contingency $c \in \mathcal{C}_{\mathcal{C}}$, for each interval in which the contingency may take place $u \in \mathbb{N}, u > 0$, for each interval thereafter $t \in \mathbb{N}, t > u$ that would be considered in the formulation, whereas under preventive security, all constraints are placed on the pre-contingency state.

- Preventive security does not require short-term generation reserves unlike corrective security.

The advantages of corrective security over preventive security are as follows.

- Any contingency may, in principle, be secured using corrective security, unless the contingency is so large that it is impossible to do so in any way. On the other hand, a contingency may be secured using preventive security only if the pre-contingency state can simultaneously satisfy pre-contingency and post-contingency constraints.

  Of the contingencies considered in this thesis, only transmission line contingencies under the DC power flow model that do not divide the system into islands may be secured using preventive security. This is because, only active power generation is considered and there are no active power losses in transmission lines. Therefore, the active power injections and therefore, the active power generation levels at every bus may remain the same while the power flows through transmission lines redistribute following the contingency. Accordingly, the modified transmission line flow constraints from (4.3) may be satisfied simultaneously with all the pre-contingency constraints.

Following a contingency, if the system were to be divided into islands, the net power injections and therefore, the total active power generation in one island would increase and in the other would decrease by the same amount. This amount would be the pre-contingency flow through the contingent transmission line such that the post-contingency net injection in each island is zero, satisfying the power balance constraints from (4.4). If preventive security were used, the contingent transmission line would be constrained to have zero flow pre-contingency such that the power balance constraints from (4.4) would be satisfied by the pre-contingency state. This would mean that the contingent transmission line would never be utilised pre-contingency.

Under the AC power flow model, transmission line losses and therefore, generation levels will change following a contingency. Therefore, these contingencies may only be secured using corrective security.

Following generator contingencies, generation levels of the remaining generators must change to account for the generation shortfall in order to satisfy the power balance constraints from (2.15) or (2.24). If preventive security were used, the contingent generators would be constrained to have zero generation levels pre-contingency such that the generator contingency constraints from (4.5) and (4.6) would be satisfied by the pre-contingency state. This would mean that the contingent generator would never be utilised pre-contingency.

- Corrective security is less costly than preventive security. This is because the pre-contingency system under preventive security would be constrained by post-contingency constraints This potentially eliminates pre-contingency states with lower operating costs from the set of feasible states that do not satisfy the post-contingency constraints. On the other hand, the pre-contingency state under corrective security only have to allow transition to a feasible post-contingency state.

4.3 Competitive market clearing

Since the real-time generation dispatch is technically a re-dispatch of the dispatch computed in the day-ahead market with updated forecasts and security constraints included, one generally expects the dispatch to not vary much [64]. Therefore, literature at this stage has often assumed that demand is inelastic, i.e., it is independent of the price such that the consumer utilities are ignored. Therefore, the competitive market clearing does not consider utilities and instead solves a cost minimisation problem. Note that the demand may still change after the day-ahead market is cleared.

For a model of real-time generation dispatch we can consider a planning horizon of T intervals. The competitive market clearing would obtain the minimum generation cost, which is

$$\min_{\left(p_j^t \mid j \in \mathcal{J}\right)} \sum_{t=1}^{T} \sum_{j} C_j\left(p_j^t\right), \tag{4.11}$$

subject to the physical constraints depending upon the power flow model used and any security constraints based on the contingencies considered and how they are modelled.

Power systems used to be operated based on solutions to the optimal power flow (OPF) problem [65], which only considered physical constraints on the power system. The inclusion of security constraints were first proposed in [66], the security-constrained OPF (SCOPF) problem. However, OPF and SCOPF are single-interval formulations, i.e., $T = 1$ and, as mentioned before, only preventive security can be modelled in single interval formulations. Therefore, SCOPF models [67] only considered transmission line contingencies. Some SCOPF formulations [68–70] model generator contingencies and propose to reserve generator capacity, i.e., limit the generation of some generators so that they may be able to compensate for the generation shortfall following a generator contingency, as a means to recover from contingencies. Note that these reserves are distinct from the short-term reserves (fast-spinning generators). The reserves mentioned here can be stably dispatched, like any other generator, over multiple dispatch intervals. However, they cannot explicitly model the corresponding contingencies and their reserve requirements but only reserve capacity in an ad-hoc manner.

However, in recent years the increase in the amount of renewable energy sources has increased intermittency in the available generation capacity [10, 71] and traditional generators are often called upon to accommodate for the increased intermittency. Since these traditional generators would have to change their generation levels based on the generation capacity of renewable energy sources, it is important to consider their ramping limits [72]. Inclusion of ramping limits couple adjacent generation levels in a formulation. The Look-ahead OPF (LAOPF) offers an extension to OPF that takes ramping limits into account [73–75].

The inclusion of security constraints into LAOPF results in the Look-ahead security-constrained OPF (LASCOPF) problem [76]. LASCOPF, due to its inclusion of ramping constraints, is intended to be robust to unanticipated changes in net demand [57]. Therefore, LASCOPF considers generation cost minimisation over a planning horizon of multiple consecutive dispatch intervals, i.e., $T > 1$, based on short-term forecasts of weather and net demand. As stated before, LASCOPF formulations have the advantage over SCOPF formulations in that they can consider contingencies that require corrective security in addition to preventive security.

Recall that the authors in [31] argue that producers internalise ramping constraints and therefore, they do not need to be considered explicitly. For these reasons, market-operators of day-ahead markets [15] and some ISOs of real-time markets [13] do not consider any ramping constraints. Therefore, these ISOs only consider SCOPF models and by consequence, must rely on an ad-hoc allocation of reserves for security. However, this is only true of the ramping constraints for the pre-contingency state in (2.3) under the assumption that producers do not behave strategically. Therefore, LASCOPF must be explicitly solved because generators do not consider security constraints.

Early LASCOPF formulations [77, 78] consider a planning horizon of two dispatch intervals, i.e., $T = 2$ where, if there is a contingency in the first interval, the dispatch in the second interval is changed. LASCOPF with $T = 2$ has also been formulated using AC power flow [77, 79, 80]. Decomposition methods have been proposed [81] to solve LASCOPF with $T = 2$ efficiently. Some LASCOPF formulations [72, 82] considered ad-hoc reserves to manage generator contingencies but explicitly considered that the deployment of reserves would depend upon their ramping constraints and therefore, modelled a planning horizon of $T = 2$.

Over the years, an increasing number of Independent System Operators (ISOs), tasked with operating real-time markets [13], have implemented LASCOPF (viz., multi-interval real-time markets) such as the ISOs in USA, NYISO [83], CAISO [84], the Midcontinent ISO [85] and PJM [86], and in Canada, Ontario's Independent Electricity System Operator (IESO) [87]. In USA, ERCOT [88,89] uses LASCOPF over five minute intervals with an hour look-ahead to obtain indicative prices. Its use is also being considered in Australia [90].

ISOs use the solution to LASCOPF to determine the dispatch in the next dispatch interval and as a prediction of the dispatch in subsequent dispatch intervals [91]. Then, after the dispatch interval is realised the problem is solved again based on an updated forecast to determine the locational marginal prices for the subsequent dispatch interval. This follows the principle of receding horizon control [92].

The authors of [93] considered LASCOPF under the $N - 1$ contingency criterion using the DC power flow but with a voltage-phase angle representation. They propose a message passing based decomposition algorithm to handle the vast computational complexity of the problem. Their formulation considers corrective security against transmission line contingencies in every dispatch interval. However, ramping constraints are imposed only on the pre-contingency dispatches as in (2.3) and between the post-contingency and pre-contingency dispatches in the interval of contingency as in (4.8). The effect of a contingency in one dispatch interval on subsequent ones and therefore, ramping limits of the form in (4.9) are ignored. There is one set of decision variables per interval for the pre-contingency state and one set for the post-contingency state per corrective contingency. Therefore, the number of decision variables is linear in the number of intervals in the planning horizon, i.e., $\mathcal{O}(T)$. A similar (but simpler) LASCOPF formulation is also used by ISOs.

The authors in [94] developed a stochastic LASCOPF formulation under the $N - 1$ contingency criterion using AC power flow for use in the event of unreliable forecasts. The authors in [95] developed a similar formulation while also considering flexible resources. However, these formulations require a computationally tractable solution to LASCOPF. Furthermore, all the LASCOPF formulations above only model the $N-1$ contingency criterion.

In this thesis, we address two formulations of LASCOPF in Papers A [96] and B [97]. In Paper A, we model LASCOPF using the DC power flow approximation given both transmission line contingencies with preventive security and generator contingencies with corrective security. In Paper B, we model a generalised LASCOPF formulation, where, instead of the competitive market clearing in (4.11), we have a generalised objective as a function of the pre-contingency dispatch, the ramping constraints (2.3) and a generalised constraint that represents the remaining physical constraints. In addition, we consider corrective security for a generalised contingency such that we consider the ramping constraints and a generalised constraint to represent the other contingency constraints. In these formulations, we consider the effect of a contingency on the remainder of the planning horizon after the contingency takes place such that we consider the ramping constraints in (2.3), (4.8) and (4.9). Our treatment of generator contingencies results in a lower cost solution than an ad-hoc allocation of reserves. This is because, we explicitly consider the pre-contingency generation levels of the contingent generator, allowing us to compute the shortfall to be covered and the ramping limits of all other generators, allowing us to optimally allocate the reserves while ensuring that ramping limits are satisfied.

First, we consider LASCOPF under the $N-1$ contingency criterion, LASCOPF$_1$. Since a contingency may take place in any interval in the planning horizon and its effect is modelled for the remainder of the planning horizon, the number of decision variables is $\mathcal{O}\left(T^2\right)$. This is represented in Figure 4.1 where a set of decision variables, where each set represents a given state of the system, is represented by a circle. Due to this, the problems may be computationally intensive. To overcome this, we formulate reduced LASCOPF, LASCOPF-r$_1$, where we assume that the post-contingency decision variables are independent of the interval u in which the contingency takes place. In Figure 4.1, all the empty circles in the same column, i.e., for the same value of t, would collapse into a single circle. This would mean that a single set of post-contingency decision variables would simultaneously satisfy (4.8) and (4.9). The number of decision variables is thus reduced to $\mathcal{O}(T)$ as in [93], even while considering a more comprehensive description of security against contingencies.

Next, unlike to other works on LASCOPF in literature, we also model the general $N-k$ contingency criterion for $k>1$. For this, we formulate LASCOPF$_k$ and reduce it to LASCOPF-r$_k$. However, due to the ramping constraints in (4.10), the decision variables in LASCOPF-r$_k$ would still depend upon the order in which contingencies would take place and therefore, the number of decision variables would be linear in the number of k-permutations of the contingencies. To improve the computational efficiency, we propose LASCOPF-ru$_k$ where decision variables are independent of the order in which contingencies would take place and therefore, the number of decision variables would be linear in only the number of k-combinations of the contingencies.

In addition, for the $N-k$ contingency criterion, for $k>1$, we propose a further reduced formulation where the decision variables are independent of the order in which the contingencies take place. We prove that, barring borderline cases, the reduced formulations are equivalent to the original ones. We carried out computational time simulations on test cases to show that the reduced formulations indeed compute faster than the corresponding original ones.

In Paper A, we prove that, barring borderline cases, if the comprehensive formulations are feasible then the corresponding reduced ones are feasible and the formulations have the same optimal solutions. In Paper B, we draw similarities between the DC and AC power flow models, and conjecture the same for the AC power flow model. In Paper A, we discussed how approaches such as Benders decomposition and contingency filtering [98, 99] can further improve computational tractability. In Paper B, we show how the generalised formulation for the $N-k$ contingency criterion for $k>1$ can be used to model recovery against contingencies.

Chapter **5**

Generation capacity investment

In this chapter, we discuss the problem of investment in generation capacity in order to facilitate investment in low-polluting generation sources. Low-polluting energy sources, by their nature, have very low operational costs [100] since they are typically fuelled by renewable energy sources like wind and solar that are free or efficient sources like nuclear. A least-cost dispatch with low-polluting energy sources in the generation portfolio would, accordingly, result in low market clearing prices in the electricity spot market, which would, in turn, result in low profits for producers. Also, shifting away from traditional power plants towards low-polluting energy plants would require high investment costs. The low profits in the electricity spot market together with high investment costs disincentivises producers to make the shift, resulting in strategic investments in generation capacity. The sections that follow model investment in generation capacity, obtain the social welfare maximising investments and strategic investments.

5.1 Model

To formulate a model of generation capacity investment, we denote by Δk_j the increase in generation capacity for generator j, where $\Delta k_j \in \mathbb{R}$ and Δk_j must be non-negative, i.e.,

$$\Delta k_j \geq 0 \; \forall j \in \mathcal{J}. \tag{5.1}$$

Let $k_j \in \mathbb{R}$ denote the generation capacity before investment such that

$$\overline{K}_j = k_j + \Delta k_j \; \forall j \in \mathcal{J}, \tag{5.2}$$

where, recall that $\overline{K}_j$ is the capacity.

Increase in generation capacity has an associated investment cost. Every generator j has an investment cost $\mathfrak{C}_j \in \mathbb{R}$, which is a function of the increase in its generation capacity, Δk_j, such that $\mathfrak{C}_j := \mathfrak{C}_j\left(\Delta k_j\right)$. Naturally, $\mathfrak{C}_j$ is non-negative, i.e., $\mathfrak{C}_j \geq 0$ and non-decreasing in Δk_j, i.e., $\partial \mathfrak{C}_j / \partial \Delta k_j \geq 0$. In addition, we assume that $\mathfrak{C}_j$ is convex in Δk_j, i.e., $\partial^2 \mathfrak{C}_j / \partial {\Delta k_j}^2 \geq 0$. Here, since $\mathfrak{C}_j$ is non-decreasing and convex in Δk_j, it is piecewise differentiable and piecewise twice-differentiable in Δk_j, respectively, with only jump discontinuities.

5.2 Social welfare maximising investment

Including the pollution externality, the social welfare in the investment timescale is the sum of social welfare created in the day-ahead market in a planning horizon of, say, T intervals less the sum of investment costs of all generators, where $T \in \mathbb{N}$. First, the maximum social welfare generated in the day-ahead market in a planning horizon of T intervals can be expressed as

$$W = \max_{\left(p_j^t, d_n^t | j \in \mathcal{J}, n \in \mathcal{N}, t \in \mathbb{N}, t \leq T\right)} \sum_{t=1}^{T} \left(\sum_n \left(U_n^t \left(d_n^t\right) - E_n \left(\sum_j A_{nj} x_n^t \right) \right) - \sum_j C_j \left(q_j^t\right) \right), \quad (5.3)$$

subject to constraints (2.1), (2.3), (2.4), (2.22), (2.24), (5.1) and (5.2). Note that $W := W \left(\Delta k_j | j \in \mathcal{J}\right)$ since the constraints (2.1) and therefore, the maximum objective value would depend upon $\left(\Delta k_j | j \in \mathcal{J}\right)$. Based on this, the maximum social welfare generated in the investment timescale is

$$\max_{\left(\Delta k_j | j \in \mathcal{J}\right)} \left(W \left(\Delta k_j\right) - \sum_j \mathfrak{C}_j \left(\Delta k_j\right) \right). \quad (5.4)$$

5.3 Strategic investment

As we discussed in Chapter 3, producers in electricity markets act strategically [49]. To mitigate the negative effects of strategic behaviour, laws exist, which force producers to generate at their entire capacity and declare their true costs to protect consumers from higher prices, e.g., in [101]. Accordingly, the price from (3.3) would not be a function of generation levels.

However, due to the KKT multiplier ω_j^t, the price would be a function of the increases in generation capacities. Therefore, as modelled by [102,103], in addition to falsely declaring higher generation costs, withholding of generation capacity would decrease generation but increase prices and overall, profits.

Producer i's profit maximisation in the investment timescale is the sum of the profits in the day-ahead market in a planning horizon of T intervals less the sum of investment costs of all generators. First, the maximum social welfare generated in

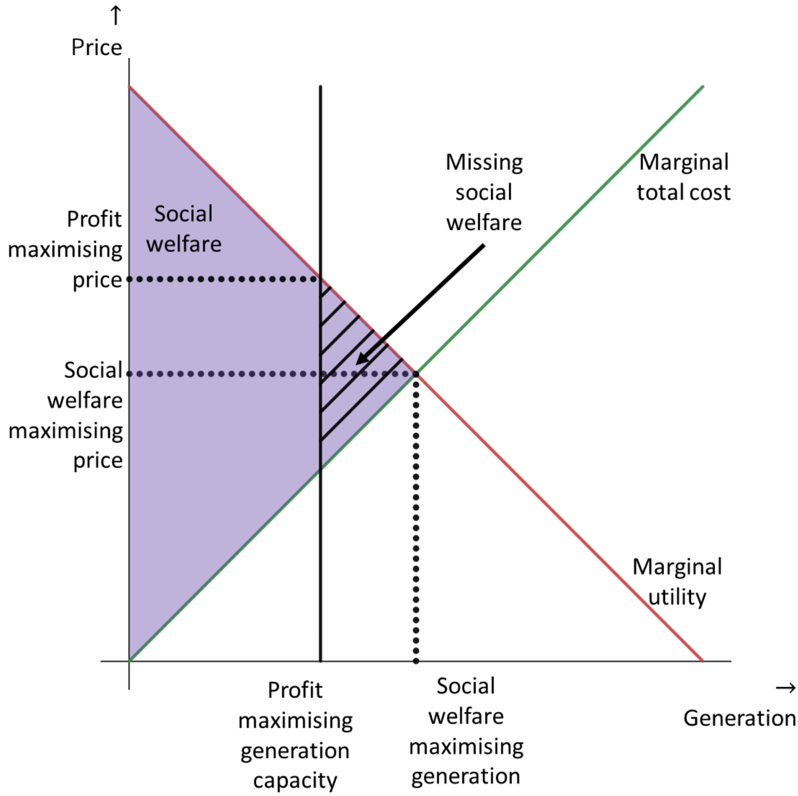

Figure 5.1: Illustration of strategic investment in generation capacity.

the day-ahead market in a planning horizon of T intervals, Y^i can be expressed as

$$Y^i = \max_{\left(p_j^t | j \in \mathcal{J}_i, t \in \mathbb{N}, t \leq T\right)} \sum_{t=1}^{T} \left(\sum_n P_n^t \sum_{j \in \mathcal{J}_i} A_{nj} p_j^t - \sum_j C_j \left(q_j^t\right) \right), \tag{5.5}$$

subject to constraints (2.1), (2.3), (5.1) and (5.2). Like W, $Y^i := Y^i \left(\Delta k_j | j \in \mathcal{J}_i\right)$. Based on this, the maximum profit generated in the investment timescale is

$$\max_{\left(\Delta k_j | j \in \mathcal{J}_i\right)} \left(Y^i \left(\Delta k_j\right) - \sum_{j \in \mathcal{J}_i} \mathfrak{C}_j \left(\Delta k_j\right) \right) \tag{5.6}$$

the optimiser of which differs from that of (5.4).

Figure 5.1 compares the competitive market clearing solution with and without strategic investment in generation capacity for a simple system with one bus and one generator. This figure illustrates the marginal consumer utility, the marginal total cost of the generator and the profit-maximising generation capacity. The marginal cost of the generator would follow the cost curve until its capacity is reached, at which point it would asymptotically increase to infinity. The social welfare maximising solution is obtained from the intersection of the marginal utility with the marginal total cost. Here, we have assumed that the social welfare maximising generation capacity is greater than the generation level. If the producer would strategically invest, the generation level would be lower and the marginal utility curve would intersect the asymptote. Therefore, the price would be higher. The solid shaded region illustrates the social welfare. Compared to the social welfare maximising solution, the profit maximising solution is missing a region of social welfare, which is striped and is not realised due to the low generation capacity. Therefore, the profit maximising investment results in lower economic welfare. The producer's profit is illustrated by the part of the solid shaded region below the price. We can see that the profit increases even though social welfare decreases.

Strategic investments [104, 105] in generation capacity would have the same effect on prices [106] as in the profit maximising optimality condition in (3.5). It incentivises producers to decrease investment in capacity. However, unlike strategic generation, laws cannot explicitly prevent strategic investments since that would entail forcing companies to invest in generation capacity. Therefore, solutions must be based on economic incentives.

There are two problems related to investment in low-polluting energy sources: a lack of consideration of pollution externalities and strategic investment in generation capacity. The authors in [41] consider the problem of pollution together with strategic behaviour in production decisions for general markets. They model pollution as a decreasing function of a continuous pollution abatement parameter and that the cost of production increases with this parameter. However, this approach may not suit electricity markets for three reasons. First, for electricity markets, the dependence of the amount of pollution on abatement efforts is negligible compared to the choice of technology. These generation technologies cannot be represented by a continuous parameter. Second, a single producer may, in general control several generation units, each with their own generation technology. Third, as we stated before, in power systems, the cost of generation is lower for lower-polluting energy sources. These problems are overcome in the formulation we propose in Paper D [43]. In Paper D, we consider a discrete set of generation technologies, each with their own pollution and costs as functions of generation levels without assuming any correlation between the two. Each producer may control multiple such units. We also explicitly model transmission lines, buses and ramping limits of generators. We also model nodal pricing, i.e., different prices at different buses where the price at one bus can depend upon the generation at another. To address the problems, we propose to levy on producers a Pigouvian tax so that producers internalise the pollution externality and grant a subsidy to producers based on their marginal contribution to the consumer surplus to incentivise socially optimal investment in generation capacity.

Chapter 6

Summary of original work

Paper A - A Scalable Formulation for Look-Ahead Security-Constrained Optimal Power Flow

Lamia Varawala, Mohammad Reza Hesamzadeh, György Dán and Ross Baldick

IEEE Transactions on Control of Network Systems, vol. 9, no. 1, pp. 138-150, Mar 2022, doi: 10.1109/TCNS.2022.3140711

Summary

In this paper, we consider the problem of obtaining the real-time generation dispatch which minimises generation costs and satisfies physical and security constraints on the power system. We consider the DC power flow approximation and model transmission line contingencies as preventive contingencies and generator contingencies as corrective contingencies. We propose the look-ahead security-constrained optimal power flow (LASCOPF) formulation, which considers the physical constraints on the power system and security constraints for transmission line and generator contingencies under the $N-1$ contingency criterion, LASCOPF_1. Since a contingency may take place in any interval of the planning horizon considered and its effect must be captured by decision variables for the remainder of the planning horizon, the number of decision variables in the formulation is a quadratic function the number of intervals in the planning horizon, making the problem computationally intensive for longer horizons. To overcome this, we propose the reduced LASCOPF formulation, LASCOPF-r_1 in which the number of decision variables is only linear in duration of the planning horizon. We prove that, barring borderline cases, if LASCOPF_1 is feasible then LASCOPF-r_1 is feasible and the two problems have equivalent optimal solutions. We also consider reduced LASCOPF under the $N-k$ contingency criterion, LASCOPF-r_k. Here, since up to k contingencies can take place in any order, the number of decision variables is linear in the number

of k-permutations of contingencies, making the problem computationally intensive for a large set of contingencies. To overcome this, we propose the further reduced LASCOPF formulation, LASCOPF-ru$_k$ in which the number of decision variables is linear in only the number of k-permutations of contingencies. We prove that, barring borderline cases, if LASCOPF-r$_k$ is feasible then LASCOPF-ru$_k$ is feasible and the two problems have equivalent optimal solutions. We simulate the LASCOPF$_1$ and LASCOPF-r$_1$ formulations on the IEEE 118-bus, the IEEE 300-bus, and the 2383-bus Polish systems to demonstrate the computational advantage of LASCOPF-r$_1$.

Contributions

The LASCOPF formulations, the proofs for the equivalence between the pairs of formulations and the numerical results were developed by the author of this thesis. The paper was written by the author of this thesis in collaboration with the co-authors.

Paper B - A Generalised Approach for Efficient Computation of Look Ahead Security Constrained Optimal Power Flow

Lamia Varawala, György Dán, Mohammad Reza Hesamzadeh and Ross Baldick

European Journal of Operational Research, 2023, doi: 10.1016/j.ejor.2023.02.018

Summary

In this paper, we consider the problem of real-time generation dispatch under the $N-1$ contingency criterion against corrective contingencies. Here, we consider a generalised formulation such that the dispatch minimises any function of the pre-contingency dispatch and satisfies any physical and security constraints on the power system. For this, we propose the generalised look-ahead security-constrained optimal power flow (LASCOPF) formulation, LASCOPF$_1$. Since a contingency may take place in any interval of the planning horizon considered and its effect must be captured by decision variables for the remainder of the planning horizon, the number of decision variables in the formulation is a quadratic function the number of intervals in the planning horizon, making the problem computationally intensive for longer horizons. To overcome this, we propose the reduced LASCOPF formulation, LASCOPF-r$_1$ in which the number of decision variables is only linear in duration of the planning horizon. We also consider LASCOPF and reduced LASCOPF under the $N-k$ contingency criterion, LASCOPF$_k$ and LASCOPF-r$_k$, respectively. Here, since up to k contingencies can take place in any order, the number of decision vari-

ables is linear in the number of k-permutations of contingencies, making the problem computationally intensive for a large set of contingencies. To overcome this, we propose the further reduced LASCOPF formulation, LASCOPF-ru$_k$ in which the number of decision variables is linear in only the number of k-permutations of contingencies. We also generalise the LASCOPF$_k$ formulation to model recovery against contingencies. Furthermore, we present LASCOPF under the contingency criterion using DC and AC power flow under generator contingencies. We prove for DC power flow and, by identifying a common structure, conjecture for AC power flow that barring borderline cases, if LASCOPF$_k$ is feasible then LASCOPF-r$_k$ is feasible and the two problems have equivalent optimal solutions. We also prove and conjecture, respectively, that, barring borderline cases, if LASCOPF-r$_k$ is feasible then LASCOPF-ru$_k$ is feasible and the two problems have equivalent optimal solutions. Finally, we present numerical results on the IEEE 14-bus, IEEE 30-bus and IEEE 300-bus test cases, and the 1354-bus part of the European power system using AC power flow to demonstrate the computational advantage of the reduced formulations under the $N-1$ and $N-k$ contingency criteria.

Contributions

The LASCOPF formulations, the proofs for the equivalence between the pairs of formulations and the numerical results were developed by the author of this thesis. The paper was written by the author of this thesis in collaboration with the co-authors.

Paper C - A Pricing Mechanism to Jointly Mitigate Market Power and Environmental Externalities in Electricity Markets

Lamia Varawala, Mohammad Reza Hesamzadeh, György Dán, Derek Bunn and Juan Rosellón

Energy Economics, vol. 121, May 2023, doi: 10.1016/j.eneco.2023.106646

Summary

In this article, we model the electricity market and explicit constraints on the power system. We model pollution as a negative externality in electricity markets. Electricity markets typically follow competitive market clearing with a least-cost dispatch which does not include negative externalities. We argue that these externalities should be integrated into the competitive market clearing. However, we show that the externalities cannot be priced since the total pollution cannot be

represented as a function of the total generation. In addition, we show that, within a competitive market framework, producers have an incentive to declare false costs to increase prices and therefore, their profits. We show that price caps are ineffective against such strategic behaviour. Therefore, we develop an incentive-based tax and subsidy mechanism equal to producers' marginal contribution to the pollution externalities and their marginal contribution to the consumer surplus. This makes producers internalise pollution externalities such that is indirectly integrated into the competitive market clearing and eliminates the incentive for strategic behaviour. We use an analytical example to demonstrate the problems and our incentive mechanism as a solution. In addition, we demonstrate price caps and how our solution overcomes the drawbacks of price caps.

Contributions

The electricity market model, the model for pollution as a function of generation and the analytical examples were developed by the author of this thesis. The paper was written by the author of this thesis in collaboration with the co-authors.

Paper D - Incentive Scheme for Efficient Generation Investment in Renewable Energy Sources

Lamia Varawala, Mohammad Reza Hesamzadeh and György Dán

Submitted for publication

Summary

In this article, we model explicit constraints on the power system, pollution due to generation and investment in generation capacity. We identify two problems in the way of reducing environmental pollution. First, pollution is a negative externality in electricity markets. Electricity markets typically follow competitive market clearing with a least-cost dispatch which does not include negative externalities. We argue that these externalities cannot be incorporated into the price since it would incentivise producers to increase pollution and propose that the market operator impose a Pigouvian tax on producers to make them internalise their marginal contribution to pollution externalities. Doing so would prioritise low-polluting generation units in the least-cost dispatch. Second, low-polluting generation units have low operational costs and therefore, when they are utilised, prices in the system are low, in turn resulting in lower profits for producers. Coupled with low profits, producers would incur high investment costs to install new low-polluting generation units. This encourages producers to invest less, strategically. To overcome

this, we propose to grant producers a subsidy equal to their marginal contribution to the consumer surplus. Finally, we show that the proposed tax and subsidy can be implemented without increasing the regulator's information burden. We use analytical examples to demonstrate how the least cost dispatch would differ when pollution externalities are considered as compared to when they are not. Also, we show that the investment in generation capacity is higher when our incentive mechanism is incorporated.

Contributions

The electricity spot market model, the model for pollution as a function of generation, the model for investment in generation capacity and the analytical examples were developed by the author of this thesis. The paper was written by the author of this thesis in collaboration with the co-authors.

Chapter 7

Conclusion and future work

7.1 Conclusion

In this thesis, we address concerns of robustness, sustainability and economic efficiency by modelling optimisation problems and developing incentive mechanisms for the day-ahead electricity market, the real-time electricity market and generation capacity investment. First, we considered secure operation of power systems and its associated computational burden. Accordingly, in Papers A and B, we answered RQ1 and RQ5. To answer RQ1, we consider the requirements of preventive and corrective security against contingencies under the $N-k$ contingency criterion. In Paper C, we model both these security types for transmission line and generator contingencies, respectively, under the DC power flow approximation. In Paper D, we provide a generalised formulation with a generalised objective function and constraints for corrective security. In later sections, we model generator contingencies under both DC and AC power flows. We note that the requirements of corrective contingencies render the formulations computationally intensive since for every interval in which the contingency may take place, a separate set of decision variables need to be defined. To answer RQ5, we propose reduced formulations for which the decision variables are independent of the contingency interval. In addition, for the $N-k$ contingency criterion, for $k>1$, we propose a further reduced formulation where the decision variables are independent of the order in which the contingencies take place. We prove that, barring borderline cases, the reduced formulations are equivalent to the original ones. We carried out computational time simulations on test cases to show that the reduced formulations indeed compute faster than the corresponding original ones.

Next, we considered environmental pollution due to power generation. Accordingly, in Papers C and D, we answer RQ2. We model environmental externalities as functions of not only the amount of power generated but the generation source used. We show that the externality cannot simply be included into the price because the total pollution cannot be expressed as a function of the total generation. Also, if it were somehow expressed in the price, it would still have to be internalised by producers otherwise it would encourage producers to increase pollution to increase prices and hence, their profits. Therefore, to answer RQ2, we propose that a Pigouvian tax be imposed by the market operator on the producer in a manner that is integrated into the competitive market clearing of day-ahead markets. The tax is implementable since the amount of subsidy can be computed by market operators based on only information they already possess.

Finally, we considered strategic behaviour of producers in electricity markets. Accordingly, in Paper C, we answered RQ3 and in Paper D, we answered RQ4. In Paper C, we show that producers can falsely declare a higher cost to increase prices and hence, their profits. However, this would result in generation levels lower than what would be socially optimal. In Paper D, we show that if producers are constrained to declare their costs truthfully, they may still strategically lower their investment in generation capacity as compared to hat is socially optimal. To answer RQ3 and RQ4, we propose to provide producers with a subsidy equal to their marginal contribution to the consumer surplus so that producers maximise the social welfare instead of their profits and generate and invest optimally. Our proposed incentive mechanism is implementable since the amount of subsidy can be computed by market operators based on only information they already possess. Typically, price caps are used to manage strategic behaviour in electricity markets. In Paper C, we show that price caps are inefficient and furthermore, show that our incentive mechanism overcomes the drawbacks of price caps while being compatible with them.

7.2 Future Work

The work done so far has interesting extensions. So far, we have considered how to incentivise producers to meet sustainability goals and to not behave strategically. On the other hand, the work on robustness of power systems resulted in algorithms for secure generation dispatch. However, it is yet to be investigated how to incentivise producers to achieve both, i.e., sustainable and secure generation dispatch through economic incentives.

For the particular case of transmission line contingencies treated preventively, the solution is straightforward. Nodal pricing, i.e., different prices at different busses in the power system arises due to transmission line constraints. As we have shown, transmission line contingency constraints under preventive security are simply the post-contingency transmission line contingencies applied to the pre-contingency variables. Therefore, if the nodal pricing would also include post-contingency transmission line constraints [107], producers would dispatch their generators in a way that is secure against transmission line contingencies.

However, the same cannot be done for generator contingencies for two reasons. First, to ensure that contingencies are small in size, generators that may face a contingency may be instructed to limit their generation. Second, in the event of a contingency, other generators need to make up for the generation shortfall. To do so, they would have to limit their generation so that they have available capacity needed to ramp up. Therefore, this would be required of fast-ramping generators in particular. This effect cannot be incorporated into the pricing since producers may be required to limit their generation even if their costs would be lower than the price. It is shown in [108] that producers may exercise strategic behaviour is by falsely declaring their ramping limits. This means that it would be possible for fast-ramping producers to falsely declare a lower ramping limit so that they do not have to reduce their generation. Therefore, an incentive mechanism would have to address this problem as well.

Another interesting research problem is to improve the sustainability of the power system while ensuring that it is secure, since sustainability and robustness are competing goals. One way to do so is to develop a method to obtain the optimal portfolio of low-polluting and fast-ramping generators for any given power system. Then, given the optimal portfolio, the incentive mechanism suggested above can be extended and perhaps incorporate Pigouvian taxes for pollution to incentivise producers to invest in these generation technologies.

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