THE BACKUP OF WIND POWER

ANALYSIS OF THE PARAMETERS INFLUENCING THE WIND POWER INTEGRATION IN ELECTRICITY GENERATION SYSTEMS

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Abstract

The research in this thesis, investigating the impact of wind power in electricity generation systems has one common aim, namely proving the existence and analysing the extent of the interaction of wind power with the electricity generation system. Wind power, just like any other electricity generation source, cannot be seen on its own. For a correct interpretation of the operation of wind power, the dynamic context it operates in needs to be known as well.

The investigation of wind power in electricity generation systems is evaluated according to three criteria, namely operational cost, system reliability and greenhouse gas emissions reduction. Several crucial parameters that influence the impact of wind power on the three criteria, such as wind speed and demand profiles, system design, fuel prices and total amount of installed wind power, are considered. The reciprocal influence of wind power and the electricity generation system can be seen within two time frames, namely the short and the long term. The two constituent elements of the intermittency of wind power, relative unpredictability and variability, are related to this subdivision in short and long term. The relative unpredictability of wind power can be linked to the short term, whereas the long term is associated with the variability of wind power. Both relative unpredictability and variability give rise to a need for backup of wind power.

The novelty of the work presented in this thesis is threefold. Firstly, the thesis creates a general framework of wind power in electricity generation systems, based on literature survey and analyses of wind speed, wind power and system aspects, to provide a good background for the study of wind power. Next, it also offers new approaches and methodologies for the investigation of wind power, such as the impact of imbalance charges based on different tariff designs from four European countries, the use of energy storage, the preservation of power reserves, the influence of system design on wind power integration and the determination of the contribution of wind power to capacity in the system. The methodologies are constructed to be easily applicable for further research. Finally, new insights are gained applying these methodologies to practical cases. These insights offer a better understanding of the many aspects of the interaction between wind power and the electricity generation systems it is integrated in, the main parameters that have to be taken into account and the critical issues that might arise.

Synopsis

Het onderzoek in deze thesis, waarbij de impact van windenergie op elektriciteitsopwekkingsystemen wordt bestudeerd, heeft een gemeenschappelijk doel, namelijk het bestaan bewijzen van de interactie tussen windenergie en systemen en het analyseren van deze interactie. Windturbines, net als elke andere eenheid voor elektriciteitsopwekking, kan niet enkel op zichzelf bekeken worden. Voor een correcte interpretatie van de uitbating van systemen met windenergie, moet de dynamische context begrepen worden.

Het onderzoek naar windenergie in elektriciteitsopwekkingsystemen wordt gevoerd volgens drie criteria, namelijk operationele kost, betrouwbaarheid van het systeem en broeikasgasemissie reductie. Verscheidene cruciale parameters die de impact van wind op deze drie criteria beïnvloeden, zoals windsnelheid- en vraagprofielen, systeemontwerp, brandstofprijzen en het totaal geïnstalleerd vermogen aan windturbines, worden beschouwd. De wederzijdse invloed van windenergie en het elektriciteitsopwekkingsysteem kan binnen lange en korte termijn gezien worden. Het intermitterende karakter van wind, dat wordt opgebouwd uit variabiliteit en relatieve onvoorspelbaarheid is gerelateerd aan deze opsplitsing in respectievelijk lange en korte termijn. Zowel variabiliteit als onvoorspelbaarheid geeft aanleiding tot een noodzaak voor backup van windenergie.

De innovatieve aspecten van het onderzoek in deze thesis zijn drieledig. Ten eerste biedt het een algemeen kader voor windenergie en elektriciteitsopwekkingsystemen, gebaseerd op literatuuronderzoek en analyses over windsnelheid, windenergie en systeemaspecten. Het doel hiervan is een goede achtergrond te verschaffen voor de studie van windenergie. In de tweede plaats levert de thesis nieuwe invalshoeken en methodes voor het onderzoek van windenergie, zoals de impact van onevenwichtskosten van vier verschillende Europese tariefontwerpen, het gebruik van energieopslag, het aanhouden van reserves, de invloed van de systeemsamenstelling op de integratie van windturbines en het bepalen van de bijdrage van windturbines tot het systeemvermogen. De methodes zijn uitgebouwd om eenvoudig bruikbaar te zijn voor verder onderzoek. Tenslotte verschaft deze thesis nieuwe inzichten door het toepassen van vermelde methodes op praktische gevallen. Deze inzichten zorgen voor een beter begrip van de vele aspecten die meespelen bij de interactie tussen windenergie en elektriciteitsopwekkingsystemen, van de voornaamste parameters die hierbij in rekening moeten gebracht worden en van de kritische kwesties die kunnen ontstaan.

Abbreviations and symbols

BRP	Balance Responsible Party
CC	capacity credit
CCS	Carbon Capture and Storage
CF	Capacity Factor
CHP	Combined Heat and Power
DC	Direct Current
EENS	Expected Energy Not Supplied
EIC	Expected Interruption Cost
ETSO	European transmission system operators
EWEA	European Wind Energy Association
FOR	Forced Outage Rate
GAMS	General Algebraic Modelling System
GDV	Gross Downward Regulation Volume
GHG	GreenHouse Gas
GUV	Gross Upward regulation Volume
HP	Heat Pump
ic	incentive component
ISET	Institut für Solare Energieversorgungstechnik
KMI	Koninklijk Meteorologisch Instituut (see RMI)
LOEE	Loss-Of-Energy Expected
LOL	Loss-Of-Load
LOLD	Loss-Of-Load Duration
LOLE	Loss-Of-Load Expectation
LOLF	Loss-Of-Load Frequency
LOLP	Loss-Of-Load Probability
MAPE	Mean Absolute Percentage Error
MILP	Mixed Integer Linear Programming
MP	Marginal Price
MP_D	Marginal Downward Regulation Price
MP_U	Marginal Upward Regulation Price
NERC	North American Reliability Council
NRV	Net Regulation Volume
PHES	Pumped Hydroelectric Storage
PLCC	Peak Load Carrying Capability
PV	PhotoVoltaic
RMI	Royal Meteorological Institute
RMP	Reference Market Price, also referred to as the spotmarket price
RMSE	Root Mean Square Error
SPF	Seasonal Performance Factor
TSO	Transmission System Operator
UC	Unit Commitment
UCTE	Union for the Co-ordination of Transmission of Electricity
WAP	Weighted Average Price
WAP_D	Weighted Average Downward regulation price
WAP_U	Weighted Average Upward regulation price

Glossary

Balance Responsible Party	A BRP has the obligation to take all reasonable measures to ensure that electricity injections and offtakes from the access points in their perimeter are always in balance.
Capacity Credit	The capacity credit is defined by how much installed wind capacity statistically contributes to the guaranteed capacity at peak load.
Capacity Factor	The capacity factor reflects the percentage of its rated capacity a wind turbine or group of wind turbines produces during a year, as expressed by the amount of full-load hours equivalents
Forecast error (negative and positive)	A negative forecast error refers to an actual output higher than the prediction. The forecast is too low and the output is underestimated. A positive forecast error refers to an actual output lower than the prediction. The forecast is too high and the output is overestimated.
BRP imbalance	A BRP imbalance in electricity generation refers to a divergence between actual and forecasted electricity generation in the BRP's perimeter. A negative BRP imbalance stands for actual electricity generation being lower than forecasted; a positive BRP imbalance refers to the opposite.
System imbalance	A system imbalance refers to a divergence between production and consumption within the control area of a TSO.
Intermittency	Electricity generation with output controlled by the external variability and unpredictability of the energy resource rather than dispatched based on system requirements.
Reliability	Reliability is a general term encompassing all measures of the ability of the electricity generation system to deliver electricity to all users within acceptable standards and in the amounts desired. The reliability of electricity generation systems can be addressed by considering two basic and functional aspects of the electric system, namely adequacy and (operational) security.

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DE BACKUP VAN WINDENERGIE

ANALYSE VAN DE INVLOEDSPARAMETERS VOOR DE INTEGRATIE VAN WINDENERGIE IN ELEKTRICITEITSOPWEKKINGSYSTEMEN

Inleiding

Context van het onderzoek

Windenergie wordt een belangrijk element in het streven naar de Europese doelstellingen voor reductie van broeikasgasemissies en elektriciteitsopwekking uit hernieuwbare energie. Het is binnen deze context dat de integratie van windenergie in elektriciteitsopwekkingsystemen wordt bestudeerd.

Doelstellingen

De nadruk van de thesis ligt op de backup van windenergie in elektriciteitsopwekkingsystemen. Wanneer windturbines in dergelijk systeem geïntegreerd worden, kunnen het ontwerp, de uitbating en betrouwbaarheidsstandaarden aan veranderingen onderworpen worden. Dit heeft een invloed op de uitbatingkost en broeikasgasemissies van het systeem. De thesis biedt verschillende kaders waarbinnen de impact van windenergie op deze elementen bestudeerd wordt. Hierbij staan het minimaliseren van de opwekkingskosten, de reductie van broeikasgasemissies en het behoud van de betrouwbaarheid centraal.

De impact van windenergie wordt geanalyseerd op korte en op lange termijn. Het uitgevoerde onderzoek is niet exhaustief maar biedt een overzicht van de vele opportuniteiten en moeilijkheden binnen de backup van windenergie. Het einddoel is een beter begrip te krijgen van de mechanismen die de invloed van windenergie op het systeem bepalen.

Deel 1
Wind en elektriciteitsopwekkingsystemen

Het eerste deel van de thesis bespreekt enkele elementen die belangrijk zijn voor een beter begrip van de wisselwerking tussen windenergie en het elektriciteitsopwekkingsysteem. Aangezien wind een natuurfenomeen is, wordt in een eerste hoofdstuk op de specifieke aspecten ingegaan. In hoofdstuk 2 wordt aandacht besteed aan de werking van het systeem op zich, met specifieke aandacht voor de betrouwbare uitbating en reserves. De wisselwerking tussen windenergie en het systeem komt aan bod in hoofdstuk 3. Hoofdstuk 4, tenslotte, introduceert de modellen voor de analyse van de backup van windenergie.

Wind: van natuurfenomeen tot energiebron

Wind is eerst en vooral een natuurfenomeen met specifieke kenmerken. Het intermitterende karakter van wind slaat op de externe factoren die het gedrag van wind bepalen. Het intermitterende van wind wordt bepaald door de variabiliteit en relatieve onvoorspelbaarheid. Windsnelheden fluctueren het hele jaar door waardoor er soms te weinig en dan weer te veel wind is om elektriciteit te genereren. De onvoorspelbaarheid van wind houdt verband met de fout die telkens aanwezig is bij het voorspellen van windsnelheden op een bepaald tijdstip vooraf.

De variabiliteit en onvoorspelbaarheid van wind manifesteren zich in verschillende tijdspannes. Windsnelheden variëren reeds op korte termijn. De variabiliteit blijft nog beperkt voor intervallen van een uur maar stijgen naarmate deze groter worden. De variabiliteit van wind op een etmaal wordt voornamelijk bepaald door hogere snelheden overdag dan ’s nachts. Ook seizoenen en jaarcycli dragen bij aan de variabiliteit.

Een belangrijke vaststelling is dat wind aanzienlijk minder variabel is wanneer grotere gebieden worden beschouwd waarbij verschillende meetpunten samen zorgen voor geografische aggregatie van de snelheden.

De omzetting van wind in elektriciteit gebeurt in turbines volgens een derdemachtsfunctie. Het maximale vermogen dat kan gehaald worden uit de wind wordt beschreven door volgende functie,

$$P_{Betz} = \frac{1}{2}\rho A v^3 C_{PBetz}$$

waar ρ de luchtdichtheid (in kg/m³) voorstelt, A de rotordiameter, v de windsnelheid en C_{pBetz} de Betz vermogenscoëfficiënt die 0.59 is. De werkelijke omzetting van wind in vermogen, wordt bepaald door de vermogenscurve die hoort bij een bepaalde turbine. In deze thesis wordt de vermogenscurve van de Vestas V80 2MW windturbine gebruikt als standaard.

Werking van elektriciteitsopwekkingsystemen

Bij het bestuderen van de integratie van bepaalde vermogens aan windturbines in elektriciteitsopwekkingsystemen is het essentieel een goed begrip te hebben over hoe deze systemen worden uitgebaat. Kostenefficiëntie en betrouwbaarheid staan hierbij centraal.

De betrouwbaarheid refereert naar de lange termijn adequaatheid (*adequacy*) en korte termijn veiligheid (*security*) van systemen. Eerstgenoemde slaat op de mogelijkheid van het systeem om de vraagbehoeftes te dekken onder alle omstandigheden, hierbij rekening houdende met mogelijke uitvallen van systeemcomponenten. Laatstgenoemde verwijst naar het vermogen van het systeem om plotse storingen zoals een elektrische kortsluiting, onverwachte verliezen van systeemcomponenten of vraagtoestanden te kunnen opvangen.

Het kostenefficiënt uitbaten van een systeem is een logisch gevolg van het gebruik van schaarse goederen. Op lange termijn dient het systeem zo uitgebouwd te worden dat de middelen zo efficiënt mogelijk kunnen aangewend worden, onder de opgelegde randvoorwaarden en investeringskosten. Op korte termijn komt het erop aan een goede allocatie van de beschikbare middelen te vinden om aan de elektriciteitsvraag te voldoen. Hierbij zal onvermijdelijk gebruik moeten gemaakt worden van reserves, die moeten instaan voor onverwachte gebeurtenissen. De transmissienetbeheerder staat in voor het contracteren van voldoende primaire, secundaire en tertiaire reserves.

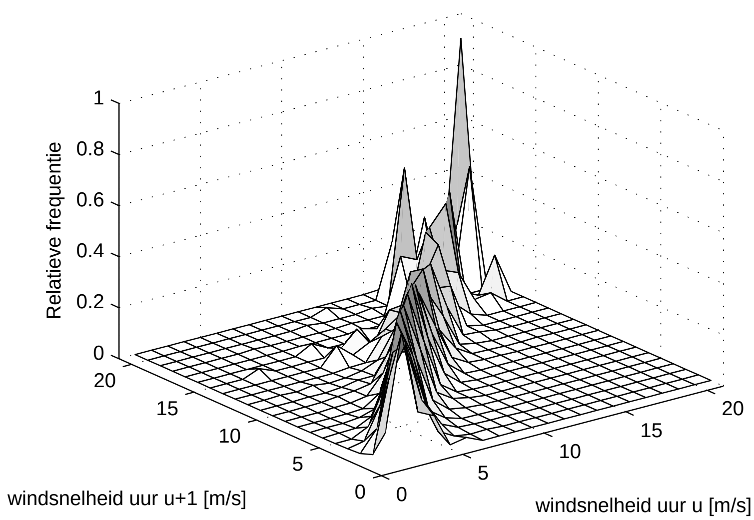
Windenergie in elektriciteitsopwekkingsystemen

De impact van windenergie op de uitbating van elektriciteitsopwekkingsystemen komt het meest tot uiting bij het vergelijken van een systeem met en zonder windturbines. Om aan een bepaalde vraag te voldoen zullen beide systemen immers verschillende centrales activeren. De windturbines hebben een duidelijke impact op de activering van centrales en beïnvloeden hierdoor de uitbatingkost en broeikasgasemissies. De interactie van windturbines met het systeem waarvan het deel uitmaakt houdt ook in dat zowel variabiliteit als onvoorspelbaarheid getemperd kunnen worden. Aangezien geen van de elementen, elektriciteitsvraag of elektriciteitsopwekking uit wind of andere bronnen, in het systeem perfect met elkaar gecorreleerd zijn, worden zowel fluctuaties als voorspellingsfouten geëffend wanneer ze als een geheel worden beschouwd.

De backup van windenergie op korte en lange termijn

Voor een diepgaande analyse van de parameters die de impact van de integratie van windturbines in elektriciteitsopwekkingsystemen bepalen, gebruikt de thesis twee modellen. Een eerste *Unit Commitment / Dispatch* model simuleert de werking van systemen. De simulatie gebeurt aan de hand van lineaire programmering met gehele getallen met een kostenminimaliserende doelfunctie ofwel *Mixed Integer Linear Programming (MILP)* voor de *unit commitment* en een normale lineaire programmeringaanpak voor de *dispatch* fase. Tijdens de *unit commitment* worden centrales toegewezen aan een bepaalde vraag, hierbij rekening houdende met technische beperkingen zoals minimum en maximum werkingspunt, *ramp rate*, efficiëntieniveaus, minimum aan en uit tijden, brandstofkosten en noodzakelijke reserves. Tijdens de *unit commitment* bestaat er geen zekerheid. De vraag en, in deze context belangrijker, de elektriciteit opgewekt door windturbines is onderhevig aan voorspellingsfouten. De beschikbare eenheden worden tijdens de *dispatch* fase op uur basis aangestuurd. Tijdens deze *dispatch* fase wordt duidelijk wat de uiteindelijke windsnelheid en bijhorende elektriciteitsopwekking is en kan een evenwicht tussen elektriciteitsvraag en -opwekking bekomen worden.

Een tweede model analyseert de betrouwbaarheid van systemen. Het is gebaseerd op een aangepast IEEE test systeem en wordt gebruikt om verschillende indices die de adequaatheid meten te bepalen. Deze zijn belangrijk in de evaluatie van de betrouwbaarheid van systemen met windenergie. De invoerwaarden zijn stochastisch bepaald. De windgegevens worden gegenereerd door middel van Markov transitie matrices, waarbij de statistische eigenschappen van wind aangewend worden om tijdseries van windsnelheden te verkrijgen. Markov matrices, die een onderscheid maken tussen dag- en seizoenscycli, bepalen wat de kans is om in uur u+1 een windsnelheid x te hebben wanneer uur u een windsnelheid y heeft. Een voorbeeld van zulke transitiematrix wordt gegeven in Figuur i. Het model wordt ook gebruikt voor het berekenen van het capaciteitskrediet (*capacity credit)* van windturbines, een maatstaf voor de lange termijn bijdrage van windturbines aan het systeemvermogen.



Figuur i: Markov transitiewaarden voor het 4400ste uur van het jaar. Het geeft de kansen weer op een bepaalde windsnelheid voor uur u+1 vertrekkende van een gegeven snelheid voor uur u.

Deel 2
Backup van wind op korte termijn

Het tweede deel van de thesis spits zich toe op de korte termijn aspecten van windenergie. Hierbij komen de voorspellingsfouten en het balanceren van het systeem aan bod in hoofdstuk 5. Het gebruik van energieopslag wordt onderzocht in hoofdstuk 6.

Onvoorspelbare wind en omgaan met voorspellingsfouten

De impact van voorspellingsfouten wordt geanalyseerd in hoofdstuk 5. Een optie voor het omgaan met stijgende aandelen aan windvermogen is het voorzien van grotere hoeveelheden vermogensreserve als backup voor de voorspelde opwekking aan elektriciteit uit wind. Een 100% backup door reserves, waarbij wind volledig als onbetrouwbaar wordt beschouwd, is mogelijk maar wordt wel zeer kostelijk voor grotere vermogens aan windturbines. Dit wordt aangetoond in hoofdstuk 5, waarbij onderzocht wordt hoeveel deze extra reserves die in het systeem worden aangehouden bijdragen aan een stijging van de uitbatingkosten.

Onevenwichtstarieven worden aangerekend door de transmissienetbeheerder voor het terug in balans brengen van de toegangsverantwoordelijken in een systeem. De invloed van het ontwerp van deze tarieven op onevenwichten door voorspellingsfouten in de windsnelheid wordt bestudeerd voor verschillende landen. Elk land heeft zijn eigen ontwerp voor het bepalen van de onevenwichtstarieven. De voornaamste kenmerken van de vier landen die in hoofdstuk 5 onderzocht worden staan opgesomd in Tabel i. Landen zoals België en Nederland, waar voornamelijk marginale kost prijszetting geldt, leiden doorgaans tot hogere kosten voor onevenwicht voor toegangsverantwoordelijken die windturbines beheren. In landen zoals Frankrijk en Spanje genieten de toegangsverantwoordelijken in de regel van een voordeliger gemiddelde kost prijszetting. De boetes die de netbeheerder oplegt bovenop de marginale of gemiddelde kosten hebben ook een invloed op de uiteindelijke kost. Nederland bijvoorbeeld rekent normaalgezien geen extra marge aan bovenop de marginale kost, en biedt hierdoor een redelijk aantrekkelijk stelsel voor toegangsverantwoordelijken met windturbines. België en Frankrijk leggen redelijk hoge boetes op waardoor, mede door extra beperkingen in de onevenwichtstarieven, hogere onevenwichtskosten ontstaan. Wanneer windturbines geïntegreerd worden in elektriciteitsopwekkingsystemen, is het duidelijk dat het van kracht zijnde onevenwichtstarief een grote invloed heeft op de backup van windenergie.

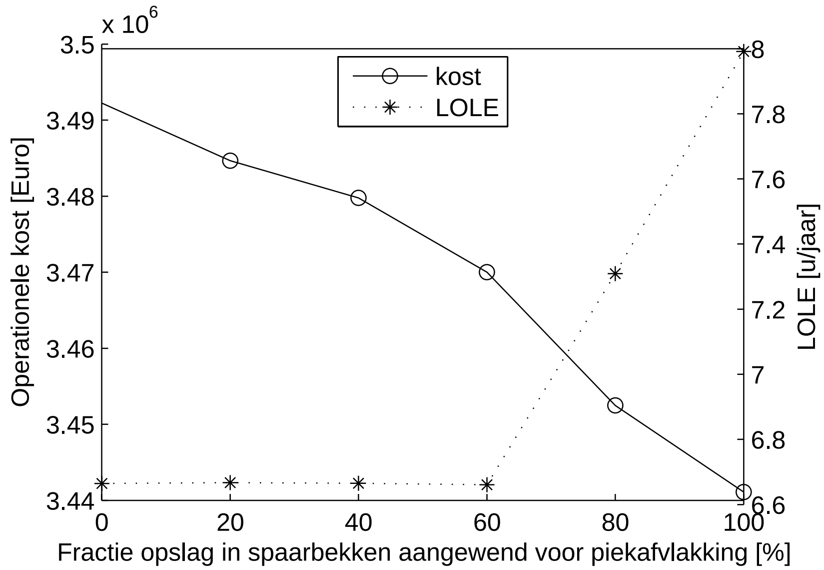
	Onevenwicht prijs	Boetes	Specifiek karakter
België	Marginale duale prijs	8%	Beperkt tot $(1 \pm 0.08) \cdot$ (marktprijs of gemiddelde prijs)
Nederland	Marginale duale prijs	geen (in praktijk)	4 regeltoestanden
Frankrijk	Gemiddelde duale prijs	5%	Beperkt door marktprijs
Spanje	Gemiddelde duale prijs	Verschil tussen gemiddelde kost en marktprijs, afhankelijk van de perimeter	perimeters

Tabel i: Overzicht van de voornaamste kenmerken van de ontwerpen voor onevenwichtstarieven in België, Nederland, Frankrijk en Spanje

Opslag van windenergie

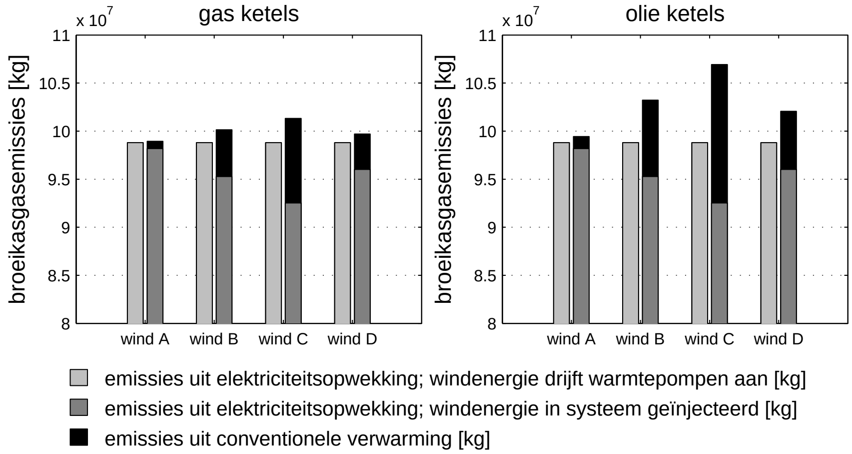
Het onderzoek van energieopslag voor de elektriciteit uit windturbines wordt besproken in hoofdstuk 6, waarbij twee specifieke methodes onderzocht worden. De eerste opslagmethode gebeurt aan de hand van spaarbekkencentrales waar water kan worden opgepompt, waarbij elektriciteit wordt verbruikt, of geturbineerd, waarbij elektriciteit wordt gegenereerd. De andere optie is de omzetting van elektriciteit in warmte door warmtepompen en de thermische opslag ervan.

De opslag via spaarbekkens kan aangewend worden voor twee doeleinden, namelijk piekafvlakking of bijdrage aan de reservecapaciteit. Het aandeel dat elke functie toegewezen krijgt kan dynamisch aangepast worden. Zoals Figuur ii illustreert, zal een stijging van het aandeel voor piekafvlakking een positieve impact hebben op de operationele kost, maar tegelijk een negatieve invloed hebben op de Loss-of-Load Expectancy (LOLE), een maat voor betrouwbaarheid van het systeem. Voor hoge windsnelheden en lage vraagprofielen kan meer opslagcapaciteit toegewezen worden aan de bijdrage tot reserves. Daarentegen wordt het voor hogere niveaus van elektriciteitsvraag en lage windsnelheden interessanter om meer opslagcapaciteit toe te wijzen aan de economische piekafvlakking.



Figuur ii: De impact van wijziging van het aandeel van het spaarbekken dat aangewend wordt voor piekafvlakking op de operationele kost en de LOLE van het systeem. Het aandeel toegewezen aan piekafvlakking is omgekeerd evenredig met het aandeel voor de bijdrage aan reservecapaciteit.

Het gebruik van warmtepompen, gecombineerd met thermische oplag laat toe om de elektriciteit uit windturbines te absorberen. Hier zijn twee voordelen aan verbonden. Enerzijds kan het, wanneer gebruikt onder de juiste voorwaarden, bijdragen tot een vermindering van broeikasgasemissies aangezien warmtepompen een efficiënte vorm van warmteopwekking zijn. Dit wordt geïllustreerd in Figuur iii, waar de scenario's met warmtepompen en thermische opslag, voor verschillende windprofielen A tot D, lagere broeikasgasemissies noteren. Anderzijds wordt, doordat de windenergie lokaal warmtepompen aandrijft, het elektriciteitsopwekkingsysteem niet belast met mogelijke variabiliteit en onzekerheid van wind.



Figuur iii: Broeikasgasemissies van het warmtepompscenario (linkse staaf van elk paar) en van het scenario met bijkomende gas- of stookoliegebaseerde verwarmingsketels, waar de elektriciteit uit windturbines in het elektriciteitsopwekkingsysteem wordt geïnjecteerd. Voor verschillende windsnelheidsprofielen.

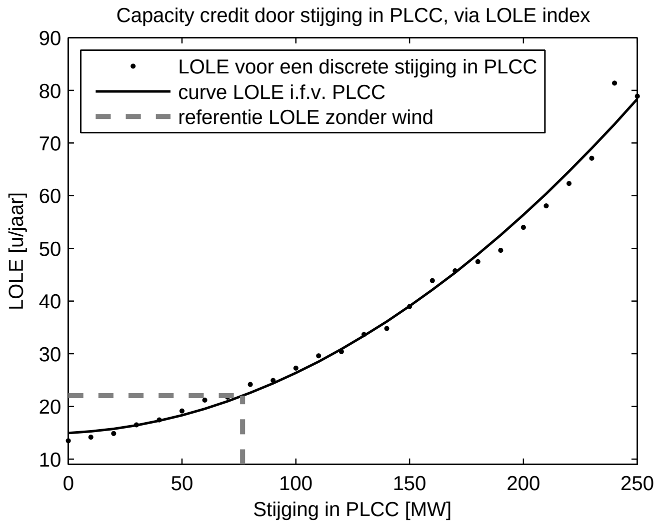
Deel 3
Backup van wind op lange termijn

In een derde deel van de thesis, worden de lange termijn aspecten van de backup van windenergie bestudeerd. In hoofdstuk 6 gebeurt dit aan de hand van een betrouwbaarheidsmodel en het bepalen van het capaciteitskrediet (*capacity credit* of *CC*). Hoofdstuk 7 onderzoekt hoe de samenstelling van centrales in een elektriciteitsopwekkingsysteem een invloed heeft op het kostenbesparingspotentieel en mogelijke reducties in broeikasgasemissies.

Lange termijn waarde van windenergie

Het betrouwbaarheidsmodel, toegepast op een aangepast IEEE testsysteem vormt de basis van de analyse van de lange termijn waarde van windenergie. De *capacity credit* geldt als maatstaf voor het bepalen van de bijdrage van windturbines aan het systeemvermogen. Vier adequaatheidsindices, namelijk *Loss-of-load expectancy (LOLE), Loss-of-energy expectancy (LOEE), Loss-of-load frequency (LOLF)* en *expected interruption cost (EIC)*, worden berekend aan de hand van simulaties van het systeem. Voor het berekenen van de *capacity credit* wordt gekeken naar hoeveel de piekvraag (*peak load carrying capability* of *PLCC*) kan stijgen om dezelfde betrouwbaarheid te bekomen als voor de introductie van een gegeven hoeveelheid windvermogen. Deze stijging in *PLCC* bepaalt de *capacity credit* van de beschouwde windturbines, zoals weergegeven in Figuur iv.

Voor de vier gebruikte adequaatheidsindices daalt de *capacity credit* met toenemend geïnstalleerd windvermogen, zoals weergegeven door de waarden in Tabel ii. De ligging van de windturbines in het net en daarmee verbonden de degelijkheid van de verbindingen van de turbines met het net bepalen ook hoe de adequaatheid van het systeem veranderd met toenemende hoeveelheden windenergie.



Figuur iv: Stijging in PLCC en bijhorende LOLE met passende kwadratische functie voor 400 MW geïnstalleerd windvermogen.

Geïnstalleerd windvermogen [MW]	CC via LOLE		CC via LOEE		CC via LOLF		CC via EIC	
	[MW]	[%]	[MW]	[%]	[MW]	[%]	[MW]	[%]
50	14.0	28.03	10.5	21.03	14.5	28.94	10.1	20.16
100	22.6	22.58	17.0	17.01	20.5	20.48	16	15.97
200	45.8	22.90	41.6	20.78	34.2	17.10	39.3	19.67
300	60.9	20.29	57.1	19.02	40.7	13.55	53.0	17.66
400	$\boxed{76.7}$	19.17	72.8	18.19	46.9	11.74	67.2	16.79
500	80.3	16.07	77.2	15.44	48.9	09.79	71.2	14.24
600	83.6	13.93	74.9	12.48	50.4	08.40	67.5	11.24

Tabel ii: Evolutie van de capacity credit binnen het testsysteem, uitgedrukt in absolute toegestane stijging van de PLCC en in verhouding tot het geïnstalleerd windvermogen. De capacity credits worden berekend voor de vier verschillende adequaatheidsindices. De omkaderde waarde komt overeen met de waarde gevonden in Figuur iv.

Impact van systeemsamenstelling op de integratie van windturbines

Bij het bestuderen van de lange termijn backup van windenergie, speelt de systeemsamenstelling een belangrijke rol. Drie verschillende samenstellingen worden hiervoor met elkaar vergeleken.

Elektriciteitsopwekkingsystemen die bestaan uit flexibelere centrales zijn beter geschikt voor de integratie van windenergie. Ze zijn het best voorzien op de aanpassingen aan de fluctuerende elektriciteitsopwekking van windturbines. Dit effect is het meest uitgesproken voor extreme windsnelheidsprofielen, gaande van vlakke tot volledig oscillerende profielen en profielen die negatief of positief gecorreleerd zijn met de elektriciteitsvraag.

De marginale centrale, die bepaalt welke de laatste eenheid is die wordt geactiveerd om aan de elektriciteitsvraag te voldoen, vormt een belangrijke determinant voor de kostenbesparing of emissiereductie ten gevolde van het investeren in windturbines. Deze marginale centrale hangt af van de combinatie aan windsnelheid- en vraagprofielen alsook van de relatieve brandstofkost. Deze brandstofkost is op zijn beurt afhankelijk van eventuele CO_2-prijzen die opgelegd worden op de brandstoffen.

THE BACKUP OF WIND POWER:

ANALYSIS OF THE PARAMETERS INFLUENCING THE WIND POWER INTEGRATION IN ELECTRICITY GENERATION SYSTEMS

0. INTRODUCTION

0.1 General context

The European Commission launched its "Climate & energy package" in January 2008 to combat climate change and improve the European Union's energy security of supply, sustainability and competitiveness [1-6]. This package implements three specific targets by 2020[1] set by the European Council in March 2007 [7]:

- 20% cut in GHG emissions compared to the 1990 levels
- 20% share of renewables in the overall EU energy mix, including 10% use of biofuels for vehicles
- Reduction of the primary energy use by improving efficiency by 20% compared to projections for 2020, as estimated by the Commission in its Green Paper on Energy Efficiency [8].

Apart from that, other recommendations are put forward, all stressing the general need for better use of energy sources. Wind power will play an important role in reaching the targets set. The importance and relevance of reducing GHG emissions is also stressed by the examination by Eurelectric to achieve a carbon-neutral electricity market by 2050 [9].

Wind is a natural resource widely available all over the world. The application of wind for energy generation purposes holds several advantages. Wind is a free resource that does not get depleted. Wind is also a zero emission[2] resource that can help contributing to a cleaner electricity generation system. In addition, wind is not subject to geo-political factors. Everyone can have access to wind and consequently reduce import dependency.

Wind also has its inconveniences. This is not specifically true when looking at the actual natural resource, but rather when wind turbine investment decisions are made or when wind power is being integrated in electricity generation systems. To be economically viable, some minimum level of local wind energy density is required. Therefore not all sites qualify for wind turbine construction. Apart from that, also population density, available space, distance to the grid or surface characteristics are

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[1] These are referred to as the "20-20-20 by 2020" as proclaimed by the then Commission President José Manuel Barroso.

[2] The zero emission aspect of wind power is only valid during its operation. In the life cycle analysis of wind turbines, emissions do occur.

to be taken into account. When these obstacles are overcome, the interaction between the wind-generated electric power output and the electricity generation system becomes the source of more important difficulties. Wind power can be considered as an intermittent energy source. Firstly, this refers to wind power not being always available. Wind power profiles are variable and the availability of wind power is not controllable, making it difficult to treat wind power generation sources in the same way as dispatchable conventional electricity generation units such as gas- or coal-fired power plants. Secondly, the output from wind turbines is not fully predictable. The relative uncertainty of wind power is another major challenge for successfully integrating wind power in electricity generation systems.

It is exactly the *intermittency* of wind power that is examined. Both variability and relative unpredictability of wind power, which define its intermittency, need to be taken into account when designing and operating electricity generation systems. Wind power can never function on its own. It will always need to operate in combination with other elements. This even is the case for wind turbines, in *isolated operation*, where still some sort of backup such as, for example, batteries, is required. When integrating wind power in existing electricity generation systems, it needs backup power. This backup can be seen in different ways, going from short term operational balancing mechanisms to investments in additional capacity in the long run. Several options exist for the effective integration of wind power. This thesis sheds some light on the important parameters for wind power integration.

0.2 Aim and scope of the thesis

The thesis focuses on the backup of wind power in electricity generation systems. When wind power is integrated into such a system, changes to the design, operation or reliability standards may become necessary. The total operational cost or greenhouse gas (GHG) emissions change accordingly. This thesis proposes different frameworks to investigate the impact of wind power on one or several of these elements.

The particular behaviour of wind as an energy source and the important parameters, both linked to the electricity generation system and the wind power itself that influence this behaviour, make up the central theme in the proposed research. Three main objectives in the integration of wind power are used to approach the issue, namely cost minimisation in electricity generation, efficient and considerable reduction of GHG emissions and preservation of the reliability of the system at a certain standard.

In the performed analyses, a cost minimisation approach is usually applied. Therefore, the changes in cost structure due to wind power integration is often used as a criterion for investigation of the impact of wind power. The choice of using GHG emissions as a basis for analysis of wind power impact on systems, can be seen in the light of policies in electricity generation aiming at reducing GHG emissions. The Kyoto protocol and all derived actions undertaken stress the importance of GHG emissions as a factor to be considered. Finally, the reliability of systems is one of the main parameters in securing energy supply. Therefore, it is also included in the research in this thesis.

The impacts of wind power integration are analysed on both long and short term. The list of performed research is not exhaustive but offers a good explorative view on many of the different opportunities and difficulties in the backup of wind power. Different setups of wind power integration are investigated and extreme situations are taken into consideration to get a better understanding of the facets surrounding the interaction of wind power with the electricity generation system. An improved comprehension of the mechanisms behind the impact of wind power on electricity generation systems can help making better policy choices and give necessary insights for all concerned players in the electricity market.

The work presented in the following is not to be seen as final solution with direct recommendations for policy. Not the actual outcomes but the applied methodology and gained insights are focused on. Because of the numerous variables and parameters that come into play, the analyses offer approaches rather than particular solutions for specific cases. The methods are designed so as to be applicable in more specific contexts.

The strategic behaviour of the different actors is not taken into consideration. Unless stated otherwise, the electricity generation system is investigated from a maximal welfare perspective. The direct implications of the introduction of wind power in a closed system are emphasised. Therefore, the interconnections between systems are not explicitly taken into account. The implications for the distribution system operator are not examined in this thesis. Assumptions have been kept to a minimum to allow for many variations being left open for examination.

0.3 Thesis structure

The thesis is structured in four parts. In Part 1, the main concepts of wind and electricity generation systems are introduced and analysed. This part covers chapters 1 to 4. Chapter 1 offers a general insight in the various elements that make wind a specific energy source. Chapter 2 briefly covers reliability and management of electricity generation systems. Chapter 3 combines chapter 1 and 2 through the linkage of wind power and electricity generation systems. Chapter 4 presents the concepts of short and long term backup of wind power, along with modelling tools used for further study of the backup of wind power.

Part 2 focuses on the short term backup aspects of wind power and comprises chapters 5 and 6. Chapter 5 investigates the impact of the relative unpredictability of wind power and how forecast errors are dealt with in the electricity generation system. Chapter 6 deals with storage of energy from wind. Two specific cases, pumped hydroelectric storage and the combination of heat pumps with heat storage are analysed.

Part 3 covers the long term issues of wind power. In chapter 7, the methods for the valuation of wind power on the long term are explained and applied. In chapter 8, the long term electricity generation system composition and its impact on wind power integration is examined, thereby considering three different system designs.

Part 4 gives the summary, conclusions and recommendations for further research on the topics analysed in this thesis.

0.4 Published work

This document can be considered as a fully comprehensible text covering the PhD research the author has performed. Much of the here discussed research has been published in, or has been submitted to, the international scientific literature. The following papers are most relevant:

- Luickx, P.J., D’haeseleer, W.D. 2007. Backup of Electricity From Wind Power: Operational Backup Methods Analysed. World Wind Energy Conference 2007, Mar del Plata, Buenos Aires, Argentina October 2-4, 2007.

- Delarue, E.D., Luickx, P.J., D’haeseleer, W.D. 2007. The effect of implementing wind power on overall electricity generation costs, CO2 emissions and reliability. Wind Power Shanghai 2007 conference, Shanghai, China November 1-3, 2007.

- Luickx, P.J., Delarue, E.D., D'haeseleer, W.D. 2008. Considerations on the backup of wind power: Operational backup. Applied Energy. 85(9), 787-799

- Luickx, P.J., Delarue, E.D., D’haeseleer, W.D. 2008. The Effect of the Generation Mix on Wind Power Introduction. European Wind Energy Conference 2008, Brussels, Belgium March 31 - April 3, 2008.

- Luickx, P.J., Delarue, E.D., D’haeseleer, W.D. 2008. The examination of different energy storage methods for wind power integration. GlobalWind 2008, Beijing, China October 29-31, 2008.

- Luickx, P.J., Delarue, E.D., D’haeseleer, W.D. 2008. Effect of the Generation Mix on Wind Power Introduction. Accepted for publication in IET Renewable Power Generation, December 2008

- Delarue, E.D., Luickx, P.J., D’haeseleer, W.D. 2009. The actual effect of wind power on overall electricity generation costs and CO2 emissions. Energy Conversion and Management. 50(6), 1450-1456

- Luickx, P.J., Delarue, E.D., D’haeseleer, W.D. 2009. The examination of different energy storage methods for wind power integration. Submitted for publication in Renewable Energy.

- Luickx, P.J., Souto Pérez, P., Driesen, J., D’haeseleer, W.D. 2009. Imbalance tariff systems in European countries and the cost effect of wind power. Submitted for publication in Energy Policy.

- Luickx, P.J., Delarue, E.D., D’haeseleer, W.D. 2009. Impact of large amounts of wind power on the operation of an electricity generation system: Belgian case study. Submitted for publication in Renewable and Sustainable Energy Reviews.

- Luickx, P.J., Vandamme, W., Souto Pérez, P., Driesen, J., D’haeseleer, W.D. 2009. Applying Markov chains for the determination of the capacity credit of wind power. 6th International Conference on the European Energy Market, Leuven, Belgium May 27 - 29, 2009.

PART 1

Wind and electricity generation systems

1. WIND: FROM NATURAL RESOURCE TO POWER SOURCE

In this first chapter, wind is described as a natural resource with its resulting advantages and disadvantages. Many of the aspects of wind as a natural resource have an impact on the actual integration of wind power in electricity generation systems. Therefore, it is important to have a good understanding of the driving forces of wind.

Firstly, wind is described as a meteorological phenomenon. Then some clarification is given on the applied terminology. Next, the key concept of intermittency is explained. The time frames and geographical space in which this intermittency operates are covered in the third and fourth section. The last section in this chapter deals with how wind speed is transformed into wind power.

1.1 Wind as a meteorological phenomenon

Most energy sources, ultimately come from the sun and its radiation. Wind power is generated by the difference between hot and cold air at distinct geographical locations. Hot air has the characteristic to rise and to move north –or southwards, respectively in the Northern and Southern hemisphere. Zones of high and low pressure appear and the Coriolis force[3] causes a general circulation of air. Apart from this general circulation, fronts, disturbances and local surface characteristics cause local and temporary weather conditions [10].

As many elements influence the wind, a different behaviour can be discerned for different locations. Wind does not behave identically in, for example Europe or Africa. A deeper insight in the behaviour of wind in Europe is given in [11]. Also within smaller regions, differences occur. Typically, wind speeds are higher near the coast or offshore than inland. The influence of these meteorological aspects is not investigated. It is essential to bear in mind that many elements, most of which are not controllable, define the actual behaviour of wind.

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[3] This is related to the rotation of the earth, diverting every movement on the Northern hemisphere to the right.

To illustrate the following characteristics of wind power, wind speed data from Belgian wind measurements sites have been used, as depicted in Figure 1 [12].

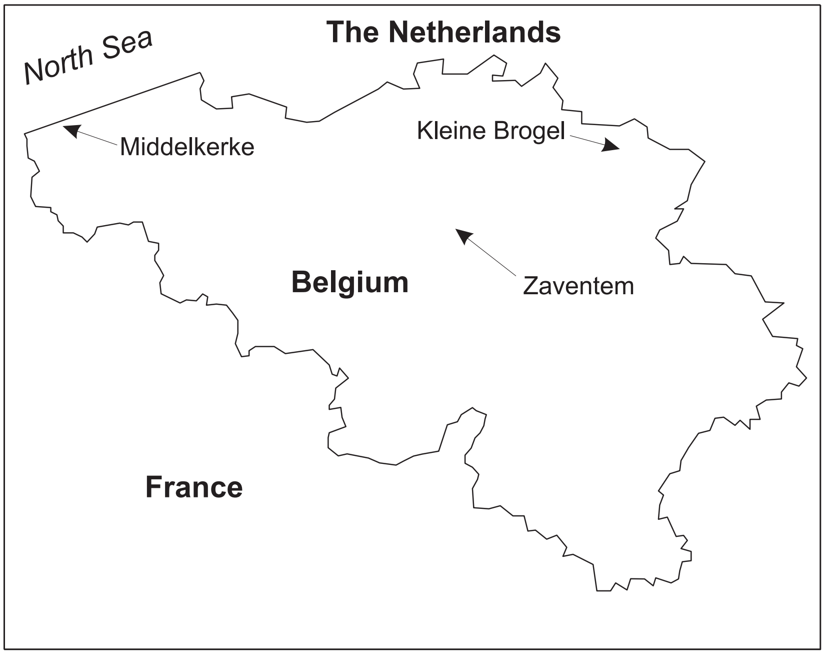

Figure 1: Map of Belgium with three wind measurement points indicated (Middelkerke, Zaventem and Kleine Brogel) (Koninklijk Meteorologisch Instituut – KMI wind measurement sites) [12].

1.2 Determination of terminology for wind power

A clear definition of terms is needed. *Wind energy* can refer to both the energy present in the natural source as to the electricity generated by wind turbines. When not explicitly referring to wind energy as a meteorological entity, it points to the output from wind turbines in the remainder of this thesis. When mentioning *wind power*, it refers to the concept of electricity generation from wind. *Installed wind power* is the installed capacity of wind turbines. *Instantaneous wind power* refers to the available power at a given moment in time.

1.3 Intermittency of wind

A determining characteristic of wind power is its intermittency and the fact that wind power is not continuously available. The availability of wind power is subject to factors outside of the operator's control.

Intermittency is a characteristic of some energy sources, mainly renewables. Their output is driven by conditions mainly out of the control of operators. Examples are wind turbines, photovoltaic cells (PV) and combined heat and power (CHP). Specifically with regard to wind power, its variability and relative unpredictability are the most obvious barriers to an easy integration and widespread application. Apart from that, the technology is relatively new. Information on wind power is not based on the same amount of experience as for conventional technologies [13].

In this section, firstly, the intermittency of wind power is defined. Subsequently, the two constituent elements of intermittency, namely variability and relative unpredictability are considered.

1.3.1 Definition of intermittency

In the context of electricity generation systems, "intermittency" indicates the non-continuous output of power plants. Starting and stopping at irregular intervals is what defines an intermittent energy source. In a strict literary sense, it also covers conventional thermal plants that, for some reason, become unintentionally unavailable. Intermittency is an issue that is commonly linked to wind power and other, non-conventional variable power plants [14].

Theoretically speaking, intermittency does not completely accurately define the behaviour of electricity sources such as wind turbines. The exact literal definition of intermittency refers to "*the coming at intervals; the operation by fits and starts*" [15] of a certain facility. The European Wind Energy Association [14], for example, states that wind power should not be denoted as an intermittent energy source. In fact, the meaning of "intermittency" depends on how exactly its definition is interpreted.

Both *variability* and *unpredictability* are used to define the particular behaviour of renewable energy installations. Renewable energy sources can, according to the UCTE [16], be classified as one of these categories: wind energy, photovoltaic or solar energy, geothermal energy, energy from biomass and waste[4] and hydro-power produced from gravity feed, tide, wave or ocean. Neither variability nor unpredictability can entirely accurately distinguish conventional thermal from renewable plants since the former can also be intermittent according to the literal definition, for example during incidents.

Although not completely accurate according to the literal definition of *intermittency*, in what follows, the terminology *intermittency* is used to describe the specific behaviour of many types of renewable electricity generation such as wind, solar, tidal and wave. It is the combination of the non-controllable variability and relative unpredictability of these energy resources. While all plants are inherently intermittent, insofar they all suffer from occasional outages, intermittent renewable generation fluctuates much more explicitly. In most cases, the contribution of fluctuating renewable energy sources to reliability is lower than for conventional thermal power plants [17]. This definition is consistent with the use of the term in most of the literature on the topic [13; 17-20]. In this context, an intermittent generator should therefore rather be interpreted as "*an electric generating plant with output controlled by the natural variability of the energy resource rather than dispatched based on system requirements.*"[21]. By extension, intermittent generation can refer to any generator with output controlled by external variability and cannot be fully forecasted.

The two constituent parts of the definition of intermittency, namely variability and unpredictability are further explained. The next section looks at the different time frames intermittency comes into play.

1.3.2 Variability

The variability is one of the elements that differentiates wind power from other generation sources. Wind speed profiles tend to fluctuate considerably. Over a year, the wind can reach speeds in two extreme directions. It can blow too softly for wind turbines to generate any electricity. It can also blow with such strength so that the turbines have to be turned out of the wind not to get damaged.

Although wind speed follows certain patterns, to be discussed in section 1.4, it is impossible to predict its behaviour in advance. The variability of wind power is a problem to consider on the long term since it determines how the electricity generation system needs to be developed. For a relatively flat wind speed profile,

[4] Such as biogas, damp gas, municipal waste, industrial waste, wood and waste of wood.

less flexible capacity is needed to cope with fluctuations than for a very rough one. A certain "backup" needs to be available for when the wind speed fluctuates towards the lower end of the speed range. Moreover, power plants need to be able to adjust fastly to a steep fluctuation of wind.

The fluctuating wind speed causes wind power variability to behave differently from the variability of other generation sources. This does not mean however that the variability of wind power by itself is more important than the variability of conventional generation sources. This is briefly illustrated in the following analysis. Firstly, the variability of a wind farm of 400 MW is compared statistically to the variability of one 400 MW gas-fired combined cycle power plant. The standard deviation of both options is taken as a means for representing the variability of generation. Secondly the same exercise is performed for multiple sites of wind farms and combined cycle power plants.

1.3.2.1 Comparison of the variability of a wind farm and a conventional generator of the same size

A first comparison of the availability of a wind farm with a combined cycle power plant is made for a specific location. Using wind speed data generated from Markov matrices[5] from the Middelkerke data[6], a 400 MW wind farm power output is simulated, according to the methods described further on in section 1.6. The standard deviations of the output of the wind farm and the combined cycle power plant are taken as measure for the variability.

The factors determining the availability of a standard combined cycle power plant are the maintenance and unforeseen outages. These cause the power plant to be unavailable. The availability of the combined cycle power plant leads to either a 0 MW or a 400 MW state. The changes from one state to another determine the plant's variability. With unavailability factors based on the 2005 data of the North American Reliability Council (NERC) General Availability Data System [22], a standard deviation of 124.55 MWh is found.

The variability of wind turbines depends on both the technical availability, which for onshore turbines is taken to be 98% [14], and the hourly fluctuations of the wind speed. For offshore wind power, two elements lead to lower overall availabilities. Firstly, offshore wind power goes together with higher wind speeds, found to cause

[5] The concept of Markov matrices is explained in chapter 4.
[6] The wind speed data are introduced in section 1.1.

lower technical availability of the turbines [23]. Secondly, the further turbines are located from the shore, the lower becomes the accessibility and availability of the turbines [24].

The transformation of wind speed to wind power according to a cubic function[7] accentuates any fluctuation in wind speed. However, the standard deviation of onshore wind power is of the same order of magnitude as the one found for the combined cycle power plant. For the 200 installed wind turbines, a standard deviation of 132.26 MWh is calculated.

Since the technical failures of 200 wind turbines are assumed to be uncorrelated, only very rare technical unavailability of onshore wind power is noted. The probability of the entire 400 MW of wind power being unavailable due to technical reasons is almost zero. For the combined cycle power plant, an unavailability of 400 MW due to technical reasons is still plausible.

On the one hand, the fluctuating wind speed causes wind power to be relatively variable. On the other hand, the technical failure of large amounts of small electricity generation units is heavily reduced when compared to the same capacity of a single power plant. Therefore, the overall difference in variability between a wind farm and a combined cycle power plant is small.

Only the variability of both generation sources is compared. The combined cycle power plant clearly can produce more power whenever available. The wind farm only generates 30% of its full-load potential. The standard deviation should be seen in the light of the average output. Moreover, a combined cycle power plant has a skewed distribution, giving it a different type of variability than a wind farm of the same size. This all illustrates how the variability of wind power is different from the variability of conventional power plants and that no real comparison is possible.

1.3.2.2 Comparison of the variability of uncorrelated distributed wind farms and conventional generators

To get a more truthful comparison of the variability of wind power and a combined cycle power plant, a dispersion of three sites with each 400 MW of installed power is investigated. The relative variability of both the combined cycle power plants and wind farms should decrease. The combined cycle power plants undergo a smoothing effect due to the technical failures of different plants being uncorrelated. The wind

[7] The transformation of wind speed to wind power is covered in detail in 1.6.

farms benefit from the same effect, with the additional effect of the geographical dispersion of wind evening out the overall wind speed fluctuations.

Standard deviations for the combined cycle and the wind farms, both representing 1200 MW of installed power are found to be 215.46 MWh and 280.31 MWh respectively. Again, these results need to be seen in the context of different average outputs.

1.3.3 Unpredictability

The second element that makes up the intermittency of wind is its relative unpredictability. Although increasingly accurate wind speed forecasting methods emerge, there always remains a certain amount of uncertainty in wind forecasting. The relative unpredictability of wind power can be seen on the short term. Wind speed forecasts are made a day to less than an hour in advance.

When dealing with forecast errors, it is important to clearly define what is to be understood by positive and negative forecast errors. The definition given at this point is used in the different chapters. A negative forecast error refers to an actual wind power output that is higher than predicted: the forecast is too low and the wind power output is underestimated. A positive forecast error refers to an actual output lower than predicted, leading to an overestimation of electricity generation from wind power.

Wind as a natural phenomenon, is suitable for statistical analysis and physical forecasting. Multiple prediction tools, based on statistical properties and historical data, exist. Forecasts are made based upon the physical description of wind fields or according to statistical methods [25-27]. Some of the major short-term wind forecasting models available on the market are enumerated by Giebel et al. [28].

The forecast accuracy strongly depends on the forecasting time horizon considered [29]. This accuracy can be evaluated through the forecast error. Two standards are commonly used to represent the forecast error, namely the Root Mean Square Error (RMSE) and Mean Absolute Error or Mean Absolute Percentage Error (MAPE) [25; 29]. For the Transmission System Operator (TSO), the forecast errors need to be as low as possible. The formula for the MAPE is given by:

$$MAPE = \frac{\sum_h |e_h - c_h|}{\sum_h c_h} .100 \tag{1.1}$$

e_h: Generation forecast for hour h
c_h: Measured generation in hour h

With current tools, the forecast error, represented by the RMSE, for a single wind farm is between 10% and 20% of the installed wind power capacity for a forecast horizon of 36 hours. Thanks to the smoothing effects, scaling up to aggregated wind power of a whole area can result in a drop of the error below 10%. Therefore, the larger the area, the better the overall prediction. Holttinen calculated that the MAPE of wind power prediction is 8-9% of installed capacity for the Nordpool electricity market [30]. Woyte found for different wind turbine sites in Belgium that forecast errors of less than 10% and 20%, occur respectively only 60-70% and 80-90% of the time [31]. In Germany, applying the *Advanced Wind Power Prediction Tool* from ISET[8], forecasts made at a given point in time a day ahead, provide the predicted wind power generation data for the entire next day. The average forecast error, expressed by the RMSE, is about 9.6% of installed capacity for a 24 to 48 hour forecast horizon [32]. This average RMSE is calculated to decrease with shorter forecast horizons. The forecast errors are situated between -10% and +10% around the forecasted value for 86% of the time, with large errors, above 20% only occurring 3% of the time.

When seen in combination with the errors in load forecast and in the forecast of the output of other thermal plants[9], the resulting forecast error is lower than the sum of the individual errors, because load and wind forecasts are not correlated [33]. It has to be stressed however that wind speed forecasts remain less accurate than load forecasts since the latter have more predictable diurnal and seasonal patterns [30]. The longer ahead the prediction horizon is situated, the higher the forecast error.

In the future, forecasts are expected to become more accurate, leading to positive effects in the wind power use. Prediction models are constantly ameliorating [34].

[8] Institut für Solare Energieversorgungstechnik, Kassel, Germany
[9] Mostly due to unexpected events such as sudden outages.

1.4 Time frames

Different time frames exist when considering wind power. On the short term, wind can already become relatively variable, especially when considering only one location, without looking at an aggregated region. On the long term, however, different aspects of intermittency are to be considered. Short and long term are defined more precisely below.

1.4.1 Wind power intermittency on the short term

The short-term wind variations are mainly due to fluctuating weather patterns and the geographical spread of the generating units [14]. The short-term variability of wind influences balancing requirements for wind, when wind turbines are integrated in a grid and thus interact with the generation mix, transmission power flows and load.

The data from the Belgian Meteorological Institute are hourly reports of wind speeds and can therefore not offer useful information regarding the behaviour of wind power on the really short run. Other studies such as [35] do look at the seconds or minutes scale performance of wind.

On the short term, variability exists within the second to within multiple consecutive days.

1.4.1.1 Seconds

The variation of wind speed on the seconds scale is reduced to a very small value once it is transformed into electricity by means of a wind turbine. The energy storing elements, such as the mechanical inertia, especially with variable speed units, take care of smoothening. Therefore, the wind turbine itself compensates part of the fluctuations on the very short time scale [36]. For a larger group of measuring points for wind power, the aggregated fluctuations within the minute become even smaller [37].

1.4.1.2 Minutes

The variations on a scale of a couple minutes become more significant. The largest variations have to do with passing storm fronts. Wind speeds can go up very fast and installed wind turbines have to be shut down once their maximum speed is reached. Variations on the minutes scale can already become important to consider when managing electricity generation systems.

1.4.1.3 Hours

The hourly intermittency of wind speed is assumed to stretch from multiple minutes to the variations on a time scale of a couple of hours. It is most frequently studied in wind power research. Wind power data are available and both variability and relative unpredictability become significant for this time scale on which predictions have to be made to plan the provision of electricity generated by wind turbines. Errors can occur for forecasts made some hours ahead.

The longer the considered timescale, the more variation occurs. This can clearly be seen in Figure 2, depicting hourly, 2-hour and 4-hour variation frequencies for wind power for Kleine Brogel (Belgium) for 1995-2006 [12]. The figure expresses the probability of change from one power output level to another within a certain time interval and this for each power output level. The 4-hour variation is much more spread out than the hourly one and tends to vary more on average. The very high probabilities of having no change[10] in wind power output between consecutive time steps, has to do with the Kleine Brogel site most of the time having zero output due to low wind speeds. For other sites, this peak in frequency at the 0 MW change level, is significantly lower.

Holttinen finds that within one hour, the step changes stay inside ± 20% of installed capacity for Sweden, Norway and Finland and a little more for Denmark [30]. The maximum 4-hour variations for each Nordic country are situated around ± 50% and for the entire Nordic area as a whole it is found to be ± 35%. Similar conclusions can be found in analyses performed by Van Wijck [38], Milborrow [19] or Johansson [39].

[10] A 0 MW change in power output actually corresponds to a band of allowed change lower than 0.5 MW.

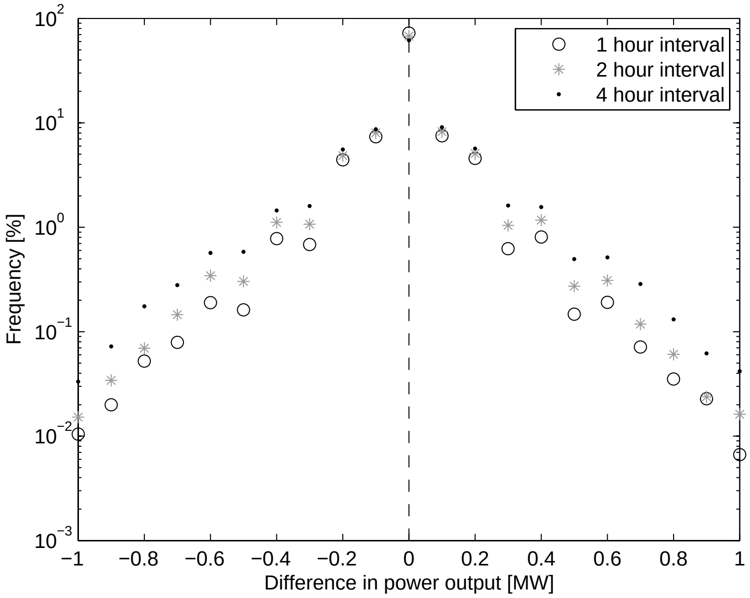

Figure 2: Hourly, 2-hour and 4-hour variation in wind power output, scaled to 1 MW for Kleine Brogel with the corresponding frequency distribution expressed as % of occurrences. Note the logarithmic scale [12].

1.4.1.4 Days

When looking at the wind speed variations during a day, an important element is the difference in average wind speed during day and night. On average, wind blows stronger during day than night [12]. This has to do with meteorological effects. When comparing this statement to actual data from Belgium, France and Germany taking the night to go from 7 pm to 6 am, it is confirmed [12; 40; 41]. Z-tests are performed on the available data from these countries to support this [42]. A z-test can be used to investigate the significance of the difference between the means of two populations. The Z-value, comparing the means of two populations is calculated as follows:

$$Z = \frac{(\bar{x}_1 - \bar{x}_2) - (\mu_1 - \mu_2)}{\sqrt{\frac{\sigma_1^2}{n_1} + \frac{\sigma_2^2}{n_2}}} \tag{1.2}$$

When investigating whether the means of both populations differ, the null hypothesis is taken to be (μ_1-μ_2) = 0, with μ_1 and μ_2 denoting the averages of the first and second population respectively. Rejecting the null hypothesis proves there is a significant difference between the mean wind speed during the day and night. $\overline{x}_1$ and $\overline{x}_2$ refer to the sample means of the first and second population, while the σ_1^2 and σ_2^2 and the n_1 and n_2 stand for the variance and sample size of both populations.

For Belgium, applying a z-test to three different stations for the years 1995 to 2006, yields z-values above 4, high enough to reject the null hypothesis for a one-tail z-test with a significance level of 5%[11]. The same conclusion holds for 8 and 14 stations for the year 2004 in France and Germany respectively.

This is consistent with what can be expected in the day-night cycle. With the rising of the sun, cold air is warmed up and turbulence is created. This gives rise to higher wind speeds. At sunset, the reverse mechanism starts.

1.4.2 Wind power intermittency on the long term

Variability of wind power exists on the longer term as well and will be driven by seasonal meteorological parameters and inter-annual variations of wind. These are not necessarily important for the daily operation and management of the grid, but do play a role in strategic system planning. A distinction can be made between monthly or seasonal variations and annual variability.

1.4.2.1 Seasons

Seasons play an important role for intermittent sources depending on meteorological circumstances. This is certainly true for wind energy. Parameters such as wind direction and speed are season-dependent. In Europe, the peaks in average available capacity of wind farms are typically situated in winter [10; 38; 43].

[11] In a statistical z-test the calculated z-value is evaluated against the rejection region of a normal table.

1.4.2.2 Years

The statistical probability density function of wind speed on an annual basis can be represented by a Weibull function [44-46],

$$f(v)=\frac{b}{v_c}.\left(\frac{v}{v_c}\right)^{b-1}.exp\left[-\left(\frac{v}{v_c}\right)^{b}\right] \quad (b>1,v>0,v_c>0) \tag{1.3}$$

where, v : wind speed,
v_c: scaling factor,
b: form parameter.
f(v)dv: probability that the wind speed is situated between *v* and *v+dv*.

In most temperate environments, *b=2*, being a Rayleigh distribution, a special case of the Weibull distribution. These functions are typically used to represent the typical behaviour of wind speed when no wind speed data are available. Figure 3 shows that the actual measured data for the 2004 Zaventem data and the Rayleigh function with the same mean value correspond well. This is also true for other comparisons between datasets and Rayleigh functions based on the same mean.

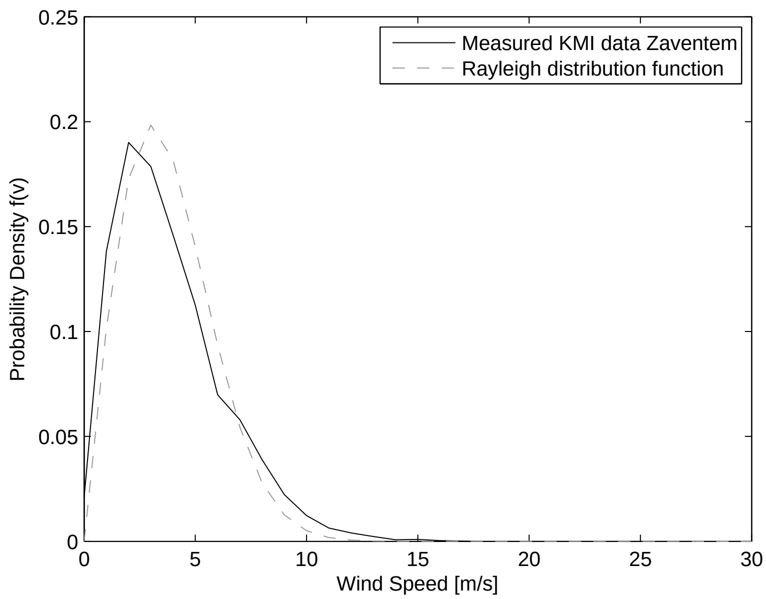

Figure 3: Example of the analogous course of a set of measurements for 2004 in Zaventem and the corresponding Rayleigh function [12].

The inter-annual variability of wind is relatively low and this for all Western European countries. Boccard [47] states that the North Atlantic oscillation approximates the long term wind evolution of Northern Europe, showing some changes over the decades. On this time horizon, the amount of wind power in the world grows rapidly. New wind farms arise on new sites, adding to the amount of wind power profiles to take into account, and mystifying the perhaps small inter-annual variability.

1.5 Geographical aggregation of variability

Apart from variability in time, wind also shows particular behaviour according to geographical location and spread. The variability of wind is very site dependent and when considering a large region, the aggregation of wind turbines reduces the extent of short-term fluctuations [37]. This area has to be large enough to allow for a significant effect, since wind fronts move at very high speeds. This movement speed determines how fast a certain wind condition shifts from one place to another. A common misconception is to believe that a wind front displaces itself at the same speed as the wind speed measured at ground level. In reality a wind front may travel at much higher speed. This causes relatively small areas to experience strongly correlated wind speeds in each measurement location. Uncorrelated measurements only occur for larger geographical areas with different wind fronts.

For individual turbines, only the variations on the second level are relatively small. For a wind farm, small variations also occur on somewhat longer timescales. For a number of wind farms spread over a large area, the variability of wind can strongly be reduced [14]. Figure 4 illustrates this. The hourly change in wind power output already has a considerably narrower spread when taking the joint output of three sites, namely Kleine Brogel, Zaventem and Middelkerke, compared to only one site, in this case Zaventem [12]. The hourly change band becomes even narrower when looking at different sites over two countries. The mix of Belgian and Dutch sites in Figure 4 is composed of the three abovementioned Belgian sites and the Dutch sites of Beek, Berkhout, Deelen, Europlatform, Hoogeveen and Vlissingen [48]. The aggregation of wind power as integrated in electricity generation systems is covered more extensively in section 3.2.

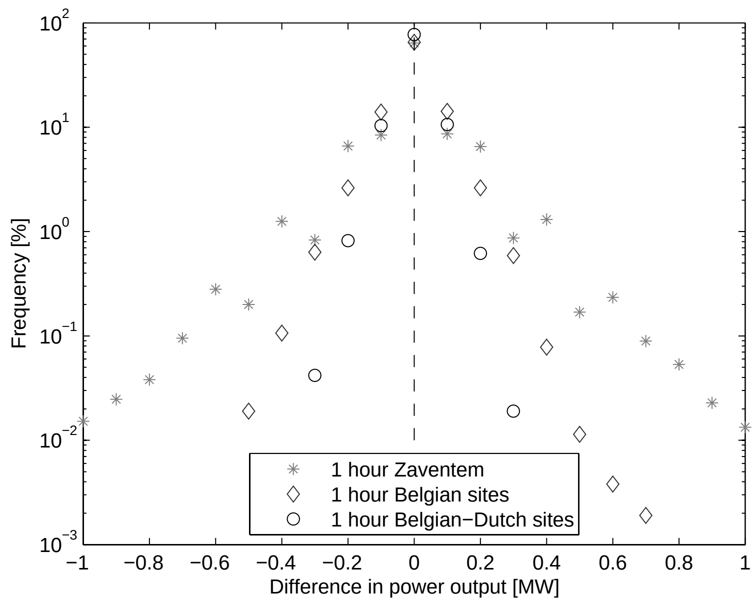

Figure 4: Hourly variation in wind power output for the Zaventem site compared to the combination of the three Belgian sites (Kleine Brogel, Zaventem, Middelkerke) and a mix of Belgian and Dutch sites with the corresponding frequency distribution expressed as % of occurrences [12; 48].

Soens et al [49] came to similar conclusions regarding the fluctuation of wind power in Belgium within one hour, using power transition and Markov matrices. Although, the geographical spread of wind turbines has beneficial effects on the expected power fluctuations, this effect should not be overestimated for a small area such as Belgium or even the Benelux. Moreover, the authors state that for large amounts of wind power to be installed in Belgium, a significant increase in backup remains necessary.

In Germany, ISET has performed analyses on wind data and found that, whereas a single wind farm can exhibit hourly power swings of up to 60% of their capacity, the maximum hourly variation of aggregated wind farms in Germany does not exceed 20% [50]. In Denmark, the difference in frequency of large variations occurring is drastically reduced when considering the entire Western Denmark area instead of a single wind farm of 5 MW [51].

Milborrow found comparable results and focused on the maximum variations in wind power on hourly and 4-hour scale [19; 33]. The larger the considered geographical area, the smaller the fluctuations of hourly variations and the lower the penalties related to wind power generation become. For small areas such as Denmark, the maximum hourly fluctuation amounts to about 30% [19]; for an area the size of Germany, 20% is the most extreme variation [17]; Holttinen found a 10% variation for the aggregated total over the Nordic countries [52]. Hurley et al report comparable reductions in 6-hour changes in wind power output for larger areas, looking at a more European perspective on the matter [11]. This has to do with weather patterns in Europe only being around 1500 km in coverage, implying wind always blowing somewhere.[12]

The duration curve of wind power generation is flattened when considering a larger area and corresponding multiple sites instead of just a single site, as illustrated by Figure 5. The duration curve of Zaventem, where wind with a capacity factor (CF)[13] of 18% over a year is generated, is already considerably steeper than the combination of three Belgian sites with a comparable aggregate capacity factor. This is also confirmed by Holttinen, who comes to the same conclusion regarding geographical smoothing when analysing the data of the Nordic countries [30]. The duration curve of wind power is flattened when considering the whole Nordic area instead of just one turbine or one country. Moreover, the standard deviation of the hourly variations in wind power is shown to decrease with increasing geographical area. However, even for a large geographical spread, the range of wind power production is still large compared to classical forms of electricity generation.

[12] It has to be borne in mind, however, that when taking into account not only wind speed over larger areas but also grid-connected wind turbines, network constraints are to be dealt with.

[13] The capacity factor defines how much wind power is produced over a year, expressed relative to its rated power. A full definition of the capacity factor is given in 1.6.3.

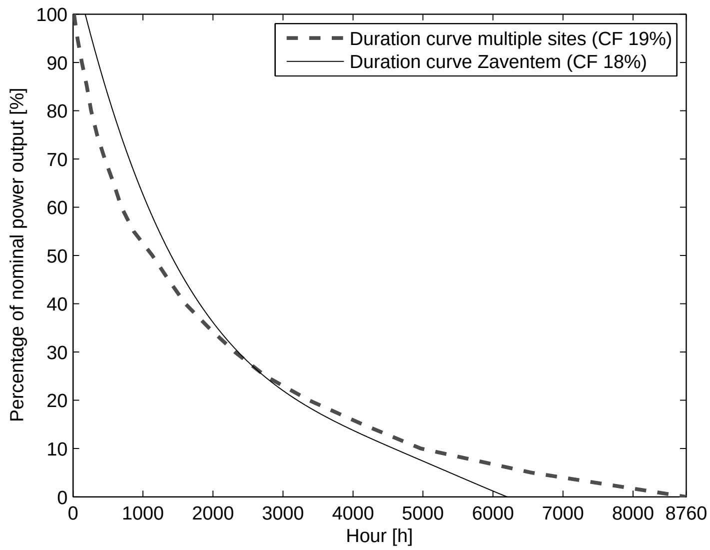

Figure 5: Duration curves of wind power generation for multiple sites (Kleine Brogel, Zaventem, Middelkerke) compared to the duration curve for Zaventem for the 2006 data [12].

1.6 From wind speed measurements to electricity from wind turbines

Wind speed data are more readily available than data on wind power output. For the conversion of wind speed data into wind power output standardized computation procedures exist. The expected power output of wind turbines depends on various parameters, being wind speed, turbine type, surface roughness and hub height.

There are numerous types of wind turbines, all with their own power curves that represent how a certain wind speed will be transformed into wind power. Two main families can be discerned in current wind power technology: doubly fed induction generator turbines such as the Vestas V80 and direct drive (gearless) turbines such as the Enercon E-126. They have different grid connection behaviour and are used for different purposes. The direct drive turbine technology, directly connecting he hub to the generator, can be used for building large wind turbines of up to 7 MW, with lower maintenance cost [53]. The Vestas V80 turbines of 2 MW remain the most popular wind turbines and are used as a reference turbine in the following. More information on types of wind turbines can be found in [54]

1.6.1 Wind speed transformation to greater altitudes

Meteorological stations typically measure wind speed at a 10 m altitude [12; 40; 41; 55]. The blades of the wind turbine that actually harvest the wind are situated at a higher point. To get relevant wind speed for a wind turbine, a transformation of the measured wind speed to hub height is needed.

Two methods are commonly used for the extrapolation to higher altitudes, namely the empirical "power law" and the "logarithmic law" [44; 45]. The parameters h_1 and h_2 represent the wind speed measurement height and the height to which it is extrapolated respectively, while v_1 and v_2 represent the corresponding wind speeds. The power law is:

$$v_2 = v_1 \left(\frac{h_2}{h_1} \right)^{\alpha} \tag{1.4}$$

with α being 0.14 for smooth surfaces, α = 0.16 more inside the country and α = 0.3 and higher for city environments and surfaces with obstructions.

The logarithmic law is:

$$v_2 = v_1 \frac{\ln(h_2 / z_0)}{\ln(h_1 / z_0)} \tag{1.5}$$

with z_0 as surface roughness being 0.2 mm for water surfaces up to 0.4m for city environments and landscapes with obstructions. The surface roughness depends on the surroundings of the wind turbines. Flat landscape results in lower surface roughness whereas relief and urbanisation will entail a higher surface roughness.

1.6.2 Wind power curve

Once the hub height extrapolated, the corresponding wind power output can be determined using the power output characteristics of the considered wind turbine. Therefore, a specific turbine's power curve is applied. It has the shape of the theoretical maximum power that can be extracted from the wind, with a cut-in and cut-out speed and a limitation on power output according to the rated power of the turbine. The theoretical maximum power that can be extracted without losses is determined by following equation, derived by Betz [44; 46; 56]

$$P_{Betz} = \frac{1}{2}\rho A v^3 C_{PBetz} \tag{1.6}$$

where ρ is the air density (in kg/m³), A the cross-section of the rotor, v the wind speed and C_{PBetz} the Betz power coefficient which is found to be 0.59.

As an example, the Vestas V80 2 MW wind turbine's power curve is given in Figure 6. The Vestas V80 is a common type of wind turbine with a cut-in speed of 4 m/s, which means that it starts generating electricity from that speed upwards. The maximum power is obtained with wind speeds of 15 m/s and higher. The cut-out speed, when the turbine has to be taken offline due to too strong wind speeds, is 25 m/s.

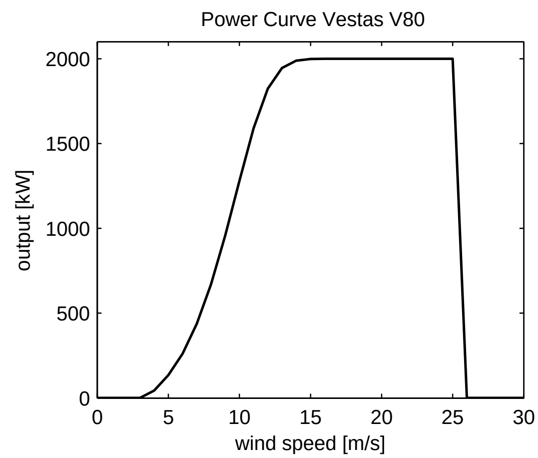

Figure 6: Power curve of Vestas V80, 2 MW wind turbine [57].

The Vestas V80 2 MW wind turbine is a variable speed pitch-controlled wind turbine. A variable speed turbine continuously adapts its rotational speed to the wind speed and can get a higher energy capture, as opposed to a fixed speed turbine. A pitch controlled turbine can turn its blades into or out the wind when the power output is too low or too high respectively. Stall controlled turbines[14] have their blades fixed at

[14] Stall control is a rather old technology and is currently seldom used.

a certain angle and due to their lower adaptability lead to lower overall wind power output. More information on the difference between a variable and fixed speed wind turbine and between stall and pitch control can be found in [44; 46; 54; 58].

In reality, wind turbines are hardly ever considered on their own. When looking at entire wind farms instead of individual turbines, aggregate wind farm power curves can be constructed. Several studies exist on how power curves for wind farms can be constructed [59; 60]. The shape of an aggregate wind farm power curve is more rounded off but by and large corresponds to the curve of the individual turbine [56]. In the further analyses, the individual Vestas V80 2 MW turbine is used for conversion of wind speed to wind power.

1.6.3 Capacity Factor

The capacity factor (CF) reflects the percentage of its rated potential a wind turbine or group of wind turbines produces during a year, as expressed by the amount of full-load hours equivalents[15]. To obtain the full-load hours equivalent of a wind turbine, the total energy output over a year is divided by 8760[16], the number of hours in a year. This represents the number of hours the wind turbine would have been operational if all that energy had been provided when the wind turbine works at rated power.

The capacity factor is calculated as follows:

$$CF = \frac{yearly\ energy\ "generation"}{installed\ capacity \cdot 8760} \tag{1.7}$$

The concept of capacity factor is important as it defines the quality of a wind turbine or wind farm site and therefore, the total average electricity generation over a year. Most interesting wind turbine locations, with high average wind speeds, yield a higher CF. Typically the CF values lie in the range of about 0.25 for relatively low wind speeds to 0.4 for high wind speeds [56]. Boccard [47] calculated that actually realized capacity factors, however, are on average lower than estimated CF values in literature; the average European CF of less than 21% is considerably lower than popular estimates.

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[15] Full-load hours equivalents are often referred to as *Effective Number of Operating Hours* (ENOH), sometimes called *yield*.

[16] The output over a year needs to be divided by 8784 in case of a leap year, when an additional day needs to be taken into account.

1.7 Conclusion

Before being able to study wind power, it is important to have a clear understanding of the origins of the natural resource. Wind power is irrevocably linked to wind as a meteorological entity, most in particular with the component of wind speed.

This chapter presents a clear setting with the definition of crucial concepts such as the intermittency of wind and its constituent parts, namely variability and relative unpredictability. The chapter is based on extensive literature survey, complemented by own calculations and analyses.

Special attention is given to the different time frames in which wind operates. The variability over different time frames is discussed, applying actual wind speed data from several meteorological institutes. Wind speed is proven to vary least when shorter time spans are taken between two wind speed measurements. A statistically significant difference between wind speed during day and night is demonstrated, applying wind speed data of various countries. Moreover, the statistical probability density function of wind speed, represented by a Weibull function, is tested against the acquired wind speed data and is shown to fit well. The impact of geographical aggregation of wind speed is studied comparing the one-hour variation of wind speed for one site, to two cases of more dispersed sites. Considering a larger area is established to have a substantial positive impact on overall wind speed variability. Finally, the methods to transform wind speed measurements to wind power data, are explained in the last part of this chapter.

2. ELECTRICITY GENERATION SYSTEMS

When considering the integration of wind power into an electricity generation system, it is necessary to understand several aspects of the operation of such system. How the system deals with existing and new energy sources determines to a major extent how easily they are incorporated. That is why this chapter deals with several aspects of the functioning of electricity generation systems. In the next chapter the specific elements of wind power integration into electricity generation systems are covered.

The different definitions given in this section are based on the "Union for the Co-ordination of Transmission of Electricity" (UCTE) terminology, as described in the UCTE operations handbook [61] but the philosophy of operation remains by and all the same for other systems.

Before elaborating on different aspects of electricity generation systems, it is important to clearly define what is to be understood by *electricity generation systems* in this thesis. Since the main angle is the investigation of bounded systems, the electricity generation system can best be described as the control zone of one transmission system operator (TSO), consisting of diverse power plants, a power grid and a certain demand that needs to be covered. In a first instance, cross-border interconnections and strategic behaviour of different players are disregarded and the pure functioning of the system, with its technical characteristics is focussed on.

Firstly, the reliability of electricity generation systems is covered, after which the necessary reserve capacity for wind power is discussed briefly.

2.1 Reliability of electricity generation systems

The electricity generation system has to satisfy electricity demand or load requirements at least cost, while maintaining a very high level of continuity and quality. Maintaining or improving the reliability of electricity generation systems is an important challenge, particularly when considering large amounts of intermittent generation sources. However, some confusion exists regarding the reliability of electricity generation systems. The terms "reliability", "adequacy" and "security" are not always clearly defined and are often used interchangeably. This section presents the way in which the used terminology is to be understood. In broad lines, the definitions on the reliability of electricity generation systems given in this section correspond to the definitions used by engineers and economists alike.

2.1.1 Reliability

Reliability is a general term encompassing all measures of the ability of the electricity generation system to deliver electricity to all users within acceptable standards and in the amounts desired [61; 62]. Eurelectric considers "reliability" and "security of electricity supply" to be closely related. Security of electricity supply is defined as "…the ability of the electrical power system to provide electricity to end-users with a specified level of continuity and quality in a sustainable manner." [63]. The *reliability* of electricity generation systems can be addressed by considering two basic and functional aspects of the electric system, namely *adequacy* and (operational) *security*. Reliability is to be seen over a certain period of time, which can be short or long term, referring to events that have to do with security or adequacy aspects. Figure 7 gives a clear view of how the different elements of reliability are linked.

To maintain the desired level of reliability, both the TSO and the balance responsible party (BRP) need to foresee reserves. The amount and the operational characteristics of these reserves vary from system to system.

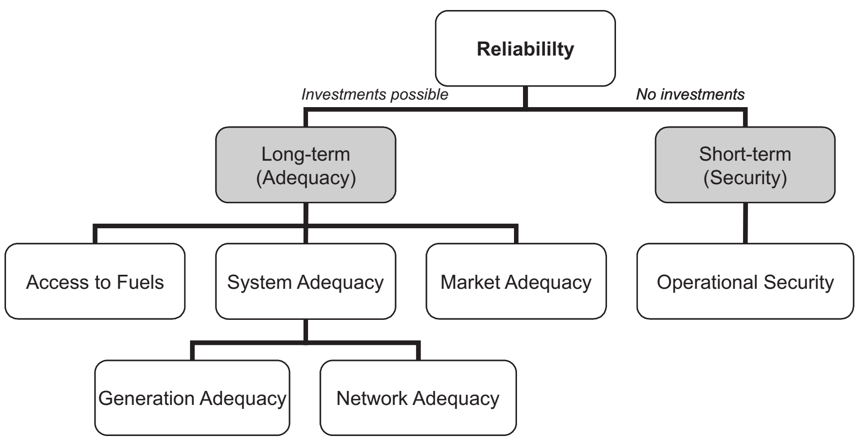

Figure 7: Different components of reliability of electricity generation systems, according to Eurelectric [63].

A distinction has to be made between interruptible load and reliability. The former refers to a load that can be stopped at a certain cost. The latter defines the probability that load that wishes to consume electricity at a certain price is able to do so [64].

2.1.1.1 Adequacy

Adequacy stands for the electricity generation system's ability to comply with demand requirements at all times. It is a measure of the ability of an electricity generation system to supply the aggregate electric power and energy requirements of the customers within component ratings and voltage quality limits, taking into account scheduled and reasonably expectable unscheduled outages of system components. Adequacy measures the ability of the electricity generation system to supply the demand in all steady states in which the power system may exist, considering standard conditions [61; 62; 65]. According to Eurelectric, adequacy can be seen on three levels, namely system adequacy, market adequacy and access to fuels adequacy [66]. For studying the effect of the integration of intermittent generation on the operation of the electricity generation system, the system adequacy is focused on. It is made up of generation and network adequacy, as can also be seen in Figure 7.

Whereas the *security* of electricity generation systems is shown to be relevant in the short run, adequacy is typically related to the long run characteristics of a system. Demand has to be met on a longer time scale, considering the inherent fluctuation in both demand and supply, the non-storability of electricity and the long lead-time for capacity expansion. Planning is required to maintain system adequacy to meet annual peak demands. Adequacy requirements are usually expressed in probabilistic terms [64]. Generation adequacy is typically measured in terms of the amounts of planning and operable reserves in the system and the corresponding loss of load (LOL), a concept often used for adequacy determination [67]. Many electricity generation systems have set targets concerning the amount of allowable loss of load events. The loss of load expectation (LOLE) in the UK for example, may not exceed 9%, meaning a maximum of 9 loss of load events per century [68]. To achieve this, a system margin of 12 to 14 GW, corresponding to about 20% of peak load, is designed in the UK. The Loss-of-Load Probability (LOLP) put forward by the North American Reliability Council (NERC) amounts to one day in ten years [69].

Adequacy indices

Several indices can be used to quantify the adequacy of an electricity generation system [17; 65; 70-74]. The most commonly used are the Loss-of-load probability (LOLP), the Loss-of-load expectancy (LOLE) and the Loss-of-energy expectancy (LOEE). The LOLP defines the probability that load exceeds the available generating capacity in a given time span, typically one hour [65; 70]. The LOLE expresses the expected number of hours within a certain period in which the system load is expected to exceed the available electricity-generation capacity [38]. LOEE, also called Expected Unserved Energy (EUE) or Expected Energy Not Supplied (EENS), gives the expected amount of energy not supplied by the electricity generation system. The Loss-of-load frequency (LOLF) looks at the amount of loss-of-load occurrences in a year. The Expected Interruption Cost (EIC) is an adequacy index taking into account the cost of loss-of-load events [75]. Indeed, not every interruption has the same impact on the system in terms of costs. The EIC gives an economic perspective on the reliability.

The LOLE, is determined as follows [65]:

$$LOLE = \sum_{i=1}^{n} P_i\left(C_i < L_i\right) \tag{2.1}$$

With n = number of hours in the considered year

C_i = available capacity in hour i

L_i = maximum load in hour i

$P_i\left(C_i < L_i\right)$ = Loss of Load Probability in hour i

The LOLE is a dimensionless number referring to probabilities of load not being covered by available capacity, summed over all hours of a year.

These indices are used later in the thesis to compare the *reliability* of different designs of an electricity generation system.

2.1.1.2 Security

Security defines the ability of an electricity system to withstand sudden disturbances such as electric short circuits, unanticipated losses of system components or load conditions [61]. In what follows, security in fact refers to operational security, as defined in Figure 7, which is not to be confused with the more general term of *security of electricity supply*. Security is to be seen in the short run. Problems leading to insecurity have to do with sudden, unforeseeable events that require immediate action. To maintain system security, the integrity of the system has to be preserved at all times. Security requirements are mostly defined in a prescriptive manner, such as the N-1 or N-2 criteria [64].

Security is provided through protection devices and operation standards and procedures such as security-constrained dispatch and so called *ancillary services.* These ancillary services include voltage support, power reserves and black start capability [67]. The determination of reserves[17] is an important element in the ability to respond to a contingency [76]. Reserves are required to cope with short-term disturbances. The balancing reserves that are required in the UK for a secure operation of the system amount to 2.5 GW or around 3.5% of peak load [68].

2.1.2 Relationship between security and adequacy

Both security and adequacy are closely linked with respect to the operation of an electricity generation system. A system with adequate capacity should have the possibility to maintain enough security to reduce periods of involuntary load shedding to a predefined level. It provides more reserve capacity to handle unforeseen disturbances more flexibly. Still, while a system with limited planning reserves may experience shortages, it can be operated in a secure way, while a system with sufficient reserve can be operated insecurely. It is relatively cheap to maintain sufficient operating reserves in an adequate system. It is relatively expensive to provide for system adequacy though [16; 67; 76].

2.2 Management of the electricity generation system

The electricity generation system needs to be managed efficiently on the long term as well as the short term. On the long term, the system design with its necessary investments needs to be considered. The focus is on installed power in the electricity generation system. On the short term, with special attention to the energy demand and generation of the system, the operation of the system is looked at. A schematic overview of the management of the system is represented in Figure 8. The reliability issues can be linked to this overview through the time scales used.

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[17] The issue of reserves is further dealt with in 2.2.2.

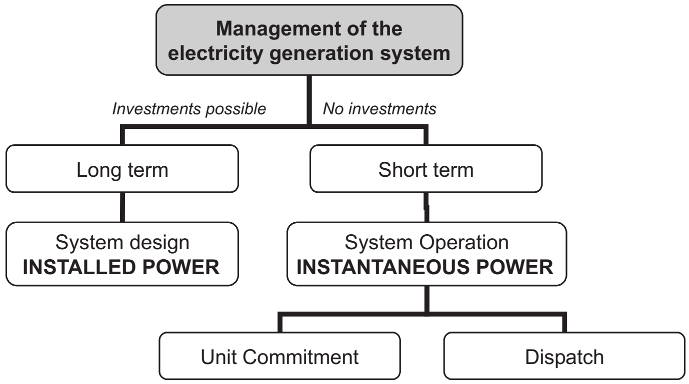

Figure 8: Management of the electricity generation system on the long and short term.

2.2.1 Long term system design

On the long term, installed power issues are mainly dealt with. The abovementioned system's adequacy needs to be maintained through sufficient investments. Investments in wind energy also have a certain value in terms of usable power but cannot be regarded as full substitutes for conventional power[18]. A careful equilibrium of the various generation options is necessary.

To effectively operate an electricity generation system while maintaining the desired level of reliability, electricity generation backup[19] is necessary. Any deviation from the foreseen level of electricity output needs to be covered by sufficient backup at all times. The backup requirements differ on the short and long term.

Long term planning of reserve is necessary to ensure a cost-effective and reliable operation of the system. This concept of reserve is used in capacity expansion. In this particular context, all available power generation means not yet addressed is considered, committed or not. As opposed to the short run, in the long run, new investments in generation capacity can be considered over several years. This issue is similar to the economics concept of long run marginal cost versus short run marginal cost.

[18] The value of wind power on the long term can be expressed by its capacity credit, which is covered in chapter 7

[19] Backup in this context refers to a more generic term of "support". The reserves are the means by which this support can be offered.

The whole point of foreseeing capacity for long-term reserves is to maintain the desired level of reliability by ensuring the availability of an adequate system. The problems arising on this level do not have to do with random fluctuations, but rather with more fundamental capacity issues an electricity generation system might incur.

To a certain extent, each power plant in an electricity generation system contributes to the capacity provision in a system. How much a generation unit can contribute to meeting system demand is expressed by its capacity credit. This concept is explained in chapter 7 in the context of the long term capacity value of wind power.

2.2.2 Short term system operation

In the use of electricity generation units, a distinction can be made between the unit commitment and the dispatch phase. During unit commitment, the planning of the generators to be used to meet demand is made. At gate closure, described later in this section, this planning comes to an end and dispatch starts. During dispatch, demand and generation have to be balanced continuously using the units previously assigned during the unit commitment phase.

Two elements are important in the operation of electricity generation systems on the short term in the light of electricity generation from wind power, namely the reserve provisions and the gate closure. Both are covered in the following two sections.

2.2.2.1 Power reserve provision by TSO on the short term

The reliability of an electricity generation system is crucial for a given control area. When considering the integration of wind power into an electricity generation system, it is necessary to understand how the reliability levels are maintained in practice. For that purpose, *power reserve*, composed of primary, secondary and tertiary reserves, is introduced. This power reserve is supplied by some of the TSO's grid users and can be used by the TSO to deal with imbalances in its control area [16; 61; 70].

Within a given system, load, increased by the grid losses, should at all times be covered by electricity generation. In order to maintain this balance, the system has to have reserve generating capacity at its disposal to deal with any disturbance affecting generation, demand or transmission. Meteorological conditions, for example, can influence both demand and generation. Colder and windier weather than forecasted, can increase the demand for electricity while at the same time making wind turbines operate at a higher than expected regime. The power reserves, under the responsibility of the TSO are intended to offset imbalances. The terminology used is general and defined by the UCTE. For more detailed information on different European operational reserve methods, [77] is referred to. An in-depth description of balancing management is offered in [78].

The primary reserve operates fully automatically on the very short seconds scale and falls completely under the responsibility of the TSO. It offers power-frequency control through the control bandwidth of power stations operating under primary frequency control. The frequency should remain at all times around 50 Hz with an allowed margin of 50 mHz. The UCTE recommends a primary control reserve margin of about 2.5% of the total installed capacity in an electricity generation system [79].

Secondary reserve offers a solution for the restoration of balance and frequency. It is activated to allow primary reserve to operate at normal level again and operates in the time-frame of seconds to typically 15 minutes [61]. Secondary reserve is continually automatically activated upwards or downwards to restore the balance and frequency. It is typically offered by power plants operating at partial load and whose output can be easily increased or decreased. Pumped hydroelectric storage can also be used for this purpose.

The tertiary reserve, is started manually by producers to restore the secondary reserve. Its purpose is to solve major or systematic imbalances, large congestions and to offset significant frequency variations. Sufficient reserve must be permanently at hands to cover the loss of a generating unit. This restoration may take up to 15 minutes. The units typically providing these reserve services are steam or gas turbines or other thermal power stations [61]. Also load shedding can be a part of tertiary reserves.

The use of power reserves to deal with imbalances is further illustrated in chapter 5.

2.2.2.2 Gate closure

The gate closure time is an important parameter in the study of backup of wind power. It defines the moment at which the unit commitment of the energy sources stops and the power plant operators have to provide their planned output for the considered period [80-82]. The gate closure time defines the boundary between unit commitment and dispatch. The gate closure time has an impact on the operation of the electricity generation system since it imposes how long ahead the forecasted electricity output needs to be declared.

An electricity generation system is composed of both fully controllable and unpredictable electricity generation units. The unpredictable output of some units, such as wind turbines highly depends on the forecast accuracy of this output. The longer ahead a forecast is made, the more unreliable it is. As a consequence, longer gate closure time inherently lead to less accurate wind speed forecasts that can be used for declaration of the planned output. Reducing the gate closure time would significantly reduce unpredicted output and, thereby, might lead to more efficient system operation without compromising system security.

Careful determination of this gate closure time is necessary. A good balance has to be found between the advantages of a gate closure far ahead of or close to actual delivery. A longer gate closure time forces the power plant operators to foresee more reserve since more uncertainty exists on the real load and electricity provision. These reserves can be contracted for in advance, usually at lower rates than on very short term. When the gate closure time falls just before actual delivery, better predictions of, mainly, wind power and load will be available, reducing the costs associated to the forecast error. However, close to the actual delivery, the acquisition of additional reserves is more costly. An anonymous day ahead market or, even better, continuous intraday trade can limit the negative effects. On the short term fewer options exist to make up for forecast errors. With the introduction of large amounts of wind power, it might well be that the currently existing gate closure times in many countries is not optimally chosen.

The gate closure time is usually situated between one and 24-36 hours ahead. The prediction accuracy of wind power can be improved by a factor of two when moving from a gate closure time of 36 hours ahead to three hours ahead [14]. While the UK and the Netherlands, for example, have a gate closure time of currently one hour (between final declaration of capacity and actual delivery), many countries have gate closure times between one and 36 hours in advance. Gate closure in France is between two and four hours ahead [83]. These times have often developed out of historic structures [37].

2.3 Conclusion

Where the previous chapter introduced important concepts relating to wind as a natural resource and its specific qualities, this chapter describes the relevant properties of electricity generation systems. First of all, an electricity generation system needs to be reliable, both on the long and the short term, referring to adequacy and security issues, respectively. Moreover, it is essential to have a good knowledge of how electricity generation systems are managed. Again, both long and short term aspects are pertinent. Regarding the short term, special attention is given to the concept of gate closure times which, together with the issue of wind speed forecast errors, influence the extent of unpredictability of wind.

3. WIND POWER IN ELECTRICITY GENERATION SYSTEMS

To use the wind-generated power effectively, the wind turbines have to be connected to the electricity generation, transmission and distribution system. The relation between an electricity demand profile and output from wind power and other generation sources is addressed in this chapter.

Firstly, two points of view for wind power integration in electricity generation systems are presented, namely wind power as negative demand and wind power as a generation source in the merit order of a system. Secondly, the importance of the aggregation of wind power with other system components is stressed. In section 3.3, the interaction of wind power with the system and the sometimes unpredictable outcomes are briefly analysed in a case study. Finally, some questions are raised as to how correctly attributing additional costs and benefits to wind power capacity.

3.1 Wind power as negative demand or generation source in a merit order

When wind power is being integrated into electricity generation systems, it is practically always be considered a "must take" electricity generation source[20]. As wind is available for free, it has the preference over other generation sources, taken that operation and maintenance costs are not excessive. Two different points of view are commonly used to analyse wind power as a must take unit.

Wind power can be considered as a negative demand or as an electricity generation source being part of the merit order. Each view has it own advantages depending on the required analyses to be performed for wind power integration. Generally speaking wind power as a negative demand is a useful approach for statistical analysis of time series, for example when comparing the demand and wind power profile. Wind power as part of the merit order is the approach best suited for

[20] Only in exceptional cases where too much must take is active in a system, some of the generated wind power is curtailed.

assessment of the impact of wind power in the operation of electricity generation systems.

3.1.1 Wind power as negative demand

Electricity from wind power can be considered as a negative demand [84]. Subtracting wind power from demand is the easiest way to investigate the impact of wind on the demand profile.

The correlation of both wind and demand determines how variable the net demand is. Wind power can amplify or reduce existing variability in the system. Wind power also impacts the uncertainty in the system. The forecast error of wind is a determining factor on the operation. Both elements are covered further in section 3.2.1.

A fictitious example of how wind power can be considered as a negative demand is illustrated in Figure 9, showing the actual wind speed and its forecast on the left and the impact on net demand on the right. The forecast error for this example is taken to be normally distributed with a standard deviation of 2 m/s being fairly large. Typical demand and wind speed profiles for a day are used and 2000 MW of installed Vestas V80 wind turbines are assumed. [21]

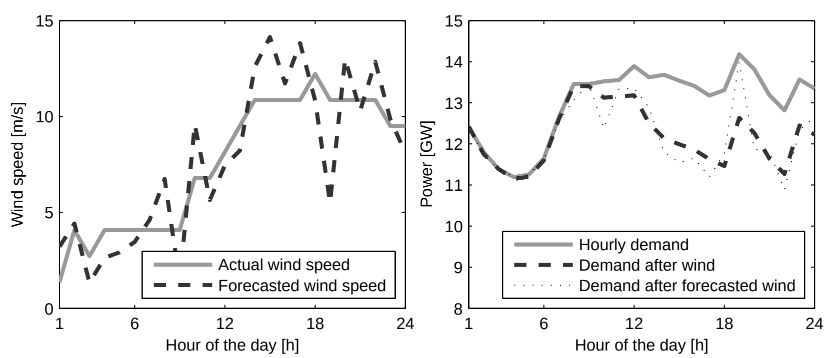

Figure 9: Left hand: actual wind speed and forecast for a day; right hand: impact of 2000 MW wind power with the given wind speed on the demand profile for one day.

[21] Typical demand and wind speed profiles are covered in section 4.2.5.

3.1.2 Wind power in the merit order

For a complete system integration approach where wind power constitutes one of the possible electricity generation sources, it becomes part of the merit order. The merit order of an electricity generation system defines the sequence in which power plants are activated to cover a given demand. This sequence is mainly determined through the electricity generation costs of the power plants[22]. As previously mentioned, wind power is usually integrated as a "must take" in the merit order of the electricity generation system.[23]

The electricity generation from wind power should not be seen separately from the system. From an economic point of view, wind power is a "must take" unit since its marginal fuel cost is zero.[24] The integration of wind power therefore has an impact on the operation of the system. The merit order of the system changes due to the addition of wind power and conventional electricity generators have a relatively lower share of total electricity generation. The interaction of wind power with the electricity generation system is illustrated in Figure 10, depicting the unit commitment of the Belgian electricity generation system for one day[25]. On the left side figure, no wind is installed. With the addition of 2 GW wind with the same wind power profile as the data from Figure 9, the operation of the system is changed, as can be seen on the right part of Figure 10. Especially gas-fired power plants are outperformed by the wind power in this particular case, but also the smaller units are used in a different way and even some slight changes occur in the use of coal-fired power plants.

[22] Technical restrictions of power plants also apply. For example, a more expensive, flexible power plant can be preferred to a cheaper one when fluctuations in demand need to be covered.

[23] In the full integration of wind power in electricity generation systems, the option of, for example, allowing the wind to be curtailed has to remain open. Wind power then cannot be seen a negative demand. Wind power integrated in the merit order is the approach applied in the model explained in section 4.2 and used in the analyses based on this model.

[24] Other costs such as operation and maintenance costs should not be omitted. They can significantly impact the total cost of wind power. Offshore turbines, for example, have high maintenance costs.

[25] The unit commitment is performed with the model further explained in section 4.2.

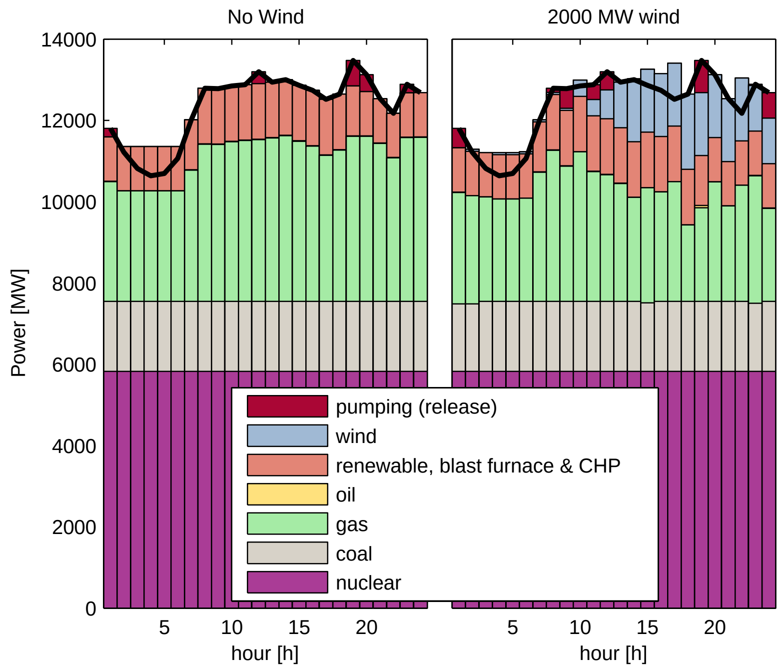

Figure 10: Unit commitment of the Belgian system for a given day with and without 2 GW of installed wind power with a certain wind power profile for the day.

3.2 Aggregation of wind and other system elements

The first and foremost element that should be taken into account when investigating the impact of wind power is that it becomes a part of the system. As such, wind power cannot be seen separately from the other system components. Wind-generated electric power interacts with electricity demand and other generation sources.

Aggregation is an important aspect of the integration of wind power in electricity generation sources [13; 56; 85]. It causes both the variability and uncertainty of wind power to be smoothed with variability and uncertainty from other sources. Grubb proves that a limited amount of a variable source hardly impacts operating costs, compared to the same amount of a conventional power plant [86].

The variability of wind power has to be seen in the context of the integration in an operational electricity generation system. Both electricity demand on the system and the conventional power plants have their own variability and unpredictability that will interact with the wind power intermittency. Before going into the statistics of wind power behaviour, first some factors that determine the incorporation of wind power into an electricity generation system are delineated.

3.2.1 Interaction of wind power with other electricity generation sources and electricity demand

3.2.1.1 Variability aspects affecting wind power integration

Investigating the combined variability of wind power and demand shows that there is an interaction between both which cannot be neglected. Basic statistics [87], represented in Eq. (3.1), show that the variability, measured by the standard deviation, decreases when considering wind power and demand together, compared to taking the sum of each of the separate components:

$$\sigma_{demand\text{-}wind} = \sqrt{\sigma^2_{demand} + \sigma^2_{wind} - 2\rho_{demand,wind}\sigma_{demand}\sigma_{wind}} \tag{3.1}$$

with $\sigma_{demand-wind}$ = combined standard deviation of the load and wind power

σ_{demand} = standard deviation of demand

σ_{wind} = standard deviation of wind power output

σ^2_{demand} = variance of demand

σ^2_{wind} = variance of the wind power output

$\rho_{demand,wind}$ = correlation between demand and wind power output

Therefore, not the separate standard deviation of wind power has to be taken into account, but only the additional effect it brings to the system. This effect depends on the correlation of wind power variability with the variability of demand.

The wind power is subtracted from demand in Eq. (3.1), as explained in section 3.1.1. When this correlation is larger than -1,[26] the standard deviation of the system as a whole will always be lower than the sum of the standard deviations of its components. When the correlation is 0, Eq. (3.1) becomes

$$\sigma_{demand\text{-}wind} = \sqrt{\sigma^2_{demand} + \sigma^2_{wind}} \tag{3.2}$$

It is clear that in the situation of Eq. (3.2), the combined standard deviation is smaller than the separate standard deviations, or $\sigma_{demand\text{-}wind} \leq \sigma_{demand} + \sigma_{wind}$.

When considering both demand and wind power, it becomes interesting when they are positively correlated. In that case, whenever the load is higher than the average load, there is a high probability that wind power output will increase as well, and so somewhat compensate for this deviation[27]. With negative correlation, increasing demand goes together with decreasing wind power output. Since, in a free market, electricity prices increase with demand, most revenues from wind power can be generated when wind power is available when demand is high. It is therefore beneficial for wind power to be positively correlated to demand.

Holttinen [30] states that the Nordic area shows a slightly positive correlation between wind power generation and demand. During the winter months, this correlation approaches zero. As demonstrated above, these low correlations will lead to lower overall variations when aggregating wind power and demand. Vogstad [88] determined a possible increased value for wind power when being incorporated in hydropower scheduling. The relations between wind power and other sources of electricity will always affect the total impact that the wind power output has on the system.

According to Eq. (3.1), the additional variation due to the integration of wind power into a system depends on the load pattern within that system. As shown in section 3.3, wind power also depends on the generating capacity already in place. This view implies that the added variation due to wind power cannot be seen separately from the other elements. Therefore the question arises whether considering wind power as the incremental power generation, is entirely fair for determining the additional

[26] A correlation of -1 stands for to the wind power and electricity demand profiles being perfectly negatively correlated. This refers to situations where wind becomes unavailable when demand is peaking

[27] An example of such a case is given in section 3.2.2.

variability of wind power on the system. In some countries, a certain amount of wind power integration might lead to a certain increase in variability, while even the same wind power profile, after integration within the there existing system and load profile, might reduce the overall variability, in another country, depending on the correlation.

3.2.1.2 Uncertainty aspects affecting wind power integration

The interaction of wind power with electricity demand is also apparent in the development of total systems uncertainty. The forecast error of wind power should not be seen completely on its own. It interacts with the forecast error of demand. Both forecast errors can be assumed to be uncorrelated or only slightly correlated. This has as a consequence that the overall uncertainty of the system is lower than the uncertainty of each element on its own.

This can also be explained by the same basic statistical theory as in the previous section. The principle also lies at the basis of classic portfolio theory [89]. The probability distribution of electricity demand and wind power output can be expressed by distribution functions, such as a normal distribution, with the standard deviation representing the forecast error. The total forecast error is only equal to the sum of both individual forecast errors in the exceptional and unlikely situation that demand and wind power output are perfectly correlated. In any other event will the total forecast error be lower than the constituent elements.

3.2.2 Total system variability with wind power: a case study for positive correlation between wind power and demand profile

Although wind power can contribute to making the overall variability higher or lower on the short term as well, the interaction of wind power generation variability with the variability of other generation sources and demand can best be seen on a long-term scale. Installing wind farms that have such profiles that smoothen peaks in electricity demand, can bring additional advantages to wind power generation.

On the longer term, wind farm construction can be planned so as to best contribute to reducing the variability of demand[28]. If the aim is to reduce the long-term variability of demand, expressed by, for example, the yearly variance or standard

[28] This is of course with the usual reservation of having adequate circumstances for building new wind farms.

deviation, careful wind power investment planning can offer a good response to this issue. If the conditions are favourable, wind power can act as a factual peak shaving option when using the correlation of wind power and demand. The right amount of investment can create an overall positive correlation of wind power with demand, with on average relatively more wind power being available on moments of high demand[29]. An example of such a positive correlation with corresponding reduction of variability of demand is given below. For this analysis, electricity generated from wind power is subtracted from the electricity demand, as explained in section 3.1.1.

On a yearly basis, it turns out that certain combinations of wind power investments can help to flatten the demand curve. This exercise has been performed on data from Belgium in 2005 and 2006 [12]. The standard deviation of electricity demand with and without certain amounts of wind power production is considered. As an illustration, the effect of 1500 MW of wind power capacity on the variability of the load is examined. For this exercise, 600 MW are considered to be installed at Kleine Brogel, 500 MW in Zaventem and 400 MW in Middelkerke, using the respective wind speed profiles and previously explained power curve transformation of wind speed to wind power for representing this. Not considering the actual overall benefit of these three wind parks, but looking only at the variability of demand before and after their introduction, the variability is observed to decrease. Whereas the standard deviations of demand for 2005 and 2006 were 1476 MWh/h and 1430 MWh/h respectively, these values decrease to 1441 MWh/h and 1416 MWh/h when subtracting the electricity from wind power generated by the three considered wind parks from this demand.[30]

Linking these results to Eq. (3.1), the correlation of the load with the considered mix of wind farms is calculated. For both 2005 and 2006, this correlation is slightly larger than 0, leading to the abovementioned decrease in overall variability. The results of this correlation between load and wind power production are illustrated in Table 1.

[29] The possible positive correlation between wind power and demand profiles follows from the fact that wind speed is usually higher during daytime, as explained in section 1.4.1.4, when demand is also higher.

[30] The significance of these standard deviations is not so much the modest decrease in overall variability, but rather the fact that, after wind power introduction, no increase is noted. The wind power in this case, has a beneficial impact on overall variability.

Year	σ_{demand}	σ_{wind}	$\sigma_{demand-wind}$	$\rho_{demand-wind}$
2005	1476 MWh/h	300 MWh/h	1441 MWh/h	0.15
2006	1430 MWh/h	320 MWh/h	1416 MWh/h	0.10

Table 1: Standard deviations of demand profiles, wind power profiles and the combined demand and wind power profiles fro 2005 and 2006. The wind power profiles originate from wind farms of 600 MW in Kleine Brogel, 500 MW in Zaventem and 400 MW in Middelkerke.

3.3 Example of unexpected interaction between wind power and the electricity generation system

Wind power is considered to be a non-polluting energy source. This element, together with the free availability of wind and the contribution to strategic security of supply in "energy" terms, make up the most interesting features of wind power. However, the overall system benefit to GHG emissions cannot really be known with certainty beforehand when wind power is integrated in an electricity generation system. As an illustration for the non-linear impact of wind power on GHG emissions, the following fictitious example is used.

Wind power is usually expected to lower GHG emissions. Since a wind turbine in itself is an emission-free power plant[31], the investment in wind power can substantially reduce overall emissions due to reduced use of thermal power plants. However, wind power introduction is not necessarily synonym for GHG reductions. Although wind turbines are considered being zero-emission power plants, the total impact on the environment when looking at the electricity generation system as a whole, is more complex. One example is that large investments in wind generation might postpone expansion of the system with, for example a gas-fired combined cycle power plant[32]. In a system with relatively low gas prices or important CO_2 taxes, this might, in turn, lead to an increased use of coal power plants at times of low wind power output. The coal power plants could otherwise have been outperformed by the CC power plant that would have been invested in.

[31] This is only considering the operation of a wind turbine, not its life cycle analysis.

[32] This is assuming that an expansion of the electricity generation capacity is necessary to follow increasing load and that either a wind farm or a combined cycle power plant can be chosen for this purpose. In reality investment choices under a cost minimizing strategy are more complex. Also political or environmental concerns might lie at the basis of investment choices to be made.

To illustrate this point, some simulations have been performed using PROMIX[33] on an electricity generation system with a balanced generation mix, such as the Belgian system in 2005, as can be seen in Table 2. Promix calculates the cost-optimal usage of the available power plants to cover the varying electricity demand over a year. This is achieved by establishing a merit order for all available plants, based on minimal marginal fuel costs. The tool takes into account the composition of the electricity generation system, the fuel costs and other country-specific parameters so as to offer a realistic simulation of the considered systems. The Promix output consists of the hourly electric power generated by each separate power plant, as well as the corresponding energy use, costs and emissions. Further information on Promix can be found in papers written by Voorspools and D'haeseleer [90; 91] and Luickx et al [92].

Power plant	Installed power [MW]
Nuclear	5700
Coal	3000
Natural gas conventional	1400
Natural gas CC	3200
Renewables	100
CHP	1600

Table 2: Belgian electricity generation system in 2005 (rounded numbers)

Two separate scenarios are calculated for 2005, under the assumption that gas-fired power plants are part of the base-load due to cheap gas prices. Both have the same input, except for some incremental generation capacity that, in scenario 1 is covered by additional gas-fired combined cycle power plants, and in scenario 2 by wind turbines with a capacity factor of almost 25%. Both scenarios represent the choice between investment in wind power and combined cycle power plants, without looking at the actual contribution to energy over a year or the capacity value of either one of the options. [34]

The additional amount of combined cycle capacity is 800 MW in scenario 1. In scenario 2, the installed wind power has a capacity of 800 MW and follows the wind

[33] A dispatching model operating under cost minimisation, used to investigate the effect of various policies on the operation of a specific electricity-generation system, developed at the division of Applied Mechanics and Energy Conversion of the Katholieke Universiteit Leuven.

[34] In that sense this comparison is not necessarily meant to be realistic. It serves as a "warning" that non-linear system effects can be dominant.

speed profile of Middelkerke for 2005[35]. The PROMIX simulations show that in this particular case, the GHG emissions will indeed increase with the introduction of 800 MW wind turbines, compared to the introduction of 800 MW gas-fired combined cycle power plants. Whereas the overall GHG emissions amount to 26110 kton for scenario 1, they total 26781 kton in scenario 2, corresponding to a 2.5% higher emission rate due to the wind power introduction in the latter case.

The higher system emissions of scenario 2 can be explained by the decrease in the use of coal-fired power plants when additional gas-fired capacity is invested in for scenario 1. This reduction in GHG emissions from using the additional gas-fired power plant cannot be compensated by the installed capacity of wind power in scenario 2.

This example evidently considers a specific situation with given fuel prices and only two potential investments which do not necessarily have the same value. Most of the time, investments in wind power will indeed lead to a reduction in GHG emissions. However, it cannot automatically be assumed that this is the case for every investment in wind power studied. That is why it is so important to always consider wind power as part of an electricity generation system with its own characteristics and needs. For additional considerations on the effect of wind power integration in an electricity generation system, [93] is referred to.

3.4 Attribution of costs to wind power

Since the impact of wind power on the electricity generation system is not known beforehand and since it varies according to many parameters that lie outside the control of the wind turbine operators, it is not clear whether assigning all of the additional cost or benefits to wind power is advisable or even fair. This incremental cost depends on many other parameters than the wind power investments themselves. A good understanding of the parameters that determine the actual impact of wind power on the operation, cost and GHG emissions of the electricity generation system is therefore necessary.

Also when the extent of the costs that can be attributed to wind power is known, the distribution of the costs over the different parties involved remains a complex issue.

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[35] The Middelkerke wind measurement site where the 2005 data are used as input at this stage, is introduced in section 1.4.

3.5 Conclusion

With the two previous chapters describing wind and electricity generation systems, respectively, this third chapter combines both elements, focussing on the interaction between wind power and electricity generation systems.

Two approaches can be used to study wind power interaction with the electricity generation system, namely by looking at electricity from wind power as negative demand or as integrated part of the generation sources in the merit order. Both approaches have their merits in terms of methodological approach.

Another facet of the integration of wind power within electricity generation systems is the aggregation of wind power with demand or other power plants in the system. By combining wind power with demand and other power plants, the variability and unpredictability of the totality of the system are usually reduced, compared to the separate operation of the constituent elements. Wind power might be a variable and unpredictable electricity generation source, but this is somewhat tempered by its interaction with demand and other power plants. An example, where the overall variability of the demand is reduced trough its interaction with wind power, is used to illustrate this fact.

The interaction of wind power with the system also results in nonlinear outcomes regarding cost savings or GHG emissions reduction. A performed simulation, using Promix as a tool, shows that, although wind turbines by themselves do not emit GHG, investing in wind power not necessarily leads to the largest reduction in GHG emissions. Other options might prove to result in better outcomes due to the dynamic behaviour of the electricity generation system.

4. BACKUP OF WIND: SHORT TERM UNCERTAINTY AND LONG TERM VARIABILITY

The backup need for wind power has its origin in the variability and relative uncertainty regarding wind as an energy source and the measures that have to be taken to cope with it. The incorporation of wind power in an electricity generation system may cause some detriment of the overall system's reliability and can increase the total system operation cost. Transmission system operators and electricity generators attempt to uphold a very high level of reliability while at the same time minimising system costs.

As in any incorporation of an element into a system, adaptations to this system have to be made to allow for its efficient and cost-effective use. The magnitude of these adaptations depends on the type and volume of these elements and the composition of the system. There is reason to believe that the integration of wind power or any other intermittent energy source in the electricity generation system will have a noticeable impact, certainly when considering the amounts mentioned by several investment plans of countries all over the world.

The backup cost is a specific type of cost which ensues from the backup of wind power. In short, it defines the costs added to the electricity generation system due to the integration of, in this specific case, intermittent power sources. It does *not* include the costs that are related to the investment or operation of the wind turbines themselves. Just like any other type of cost and in the same logic as the distinction made in section 1.4, it can be seen on the short and the long term. The short term is taken to reflect the operational part of the backup and instantaneous power-related matters. The long term encompasses the capacity issues of backup and is related to the installed power questions of incorporating wind energy.

This chapter first introduces the concept of backup of wind power, both for the short and the long term. Next the two tools used to model the short and long term are covered in sections 4.2 and 4.3, respectively.

4.1 Backup of wind power on the short and long term

The short- and long-term approach of wind power and the management of electricity generation systems can also be applied to the backup of wind power, as explained by Gross et al [68]. On the short term, all relevant decisions have to be made taking into account the configuration of the electricity generation system with no additional investments. Speaking in economic terms, the short term is too short to change the system fundamentally. On the long term, however, new investments in both electricity generation system and grid are an option that has to be taken into account [94]. This investment option allows market players to choose from a larger radius of alternatives to achieve the most cost-efficient delivery of electricity and its related services, under the considered boundaries.

Operational and backup capacity issues can be linked to the short term and the long term, respectively. Assuming that investment decisions only arise when considering capacity-related problems, it is possible to assign the operational actions to the short term and the capacity-related matters to the long term. The different elements that make up the backup of these sources, and more in particular wind power, are, in broad terms, consistent with the literature such as [17; 18; 35; 37; 95-99].

4.1.1 Instantaneous power issue on the short term

On the short term, wind power has to be integrated in electricity generation systems in a way that electricity generation and demand, including transmission and distribution losses, are always balanced. The relative unpredictability of wind power brings about a constant need for adaptations to the system to meet expected but not quite predictable changes. Backup is needed in the form of balancing reserves. The backup of wind power on the short term therefore can best be considered as a part of *system and BRP operation balancing* [17].

As described in section 2.2., the distinction can be made between the unit commitment (UC) and the dispatch phase. Wind speed and ensuing wind power forecasts are typically made during the UC phase and submitted, together with the planning of the rest of the electricity generation, to the TSO at gate closure time. The system is faced with the actual wind power output during dispatch. The power plants that are activated and that therefore can serve as backup, however, have been decided upon during the UC. The model used in this thesis simulating the UC-dispatch operation of the electricity generation system is presented in section 4.2.

4.1.2 Installed power issue on the long term

When considering the capacity component of the backup for wind power, two related key elements come into play, namely the investment option and the capacity credit. They are both to be seen in the light of the variability of wind power[36].

The focus on the amount and type of capacity in the electricity generation system is to be seen in the context of the adequacy of the system. An electricity generation system has to be able to provide a very reliable electricity output at all times. This requirement is a logical consequence of the inability of electricity to be stored as such. Careful planning on the long term is therefore an essential part of electricity provision. In the last few decades, variable sources have been added to the systems and this has had and will have serious impacts on the preservation of the adequacy of the system. With more variable elements in the system, a need arises for additional backup capacity.

It is generally assumed that intermittent sources tend to lower the reliability when they are preferred to more conventional power generation units and when no additional measures are taken. In future, significant amounts of wind power will be added to electricity generation systems. The adequacy level however, has at least to remain constant and to achieve this, other power sources are needed to provide backup for wind power. Careful determination of the necessary investments in electricity generation systems to uphold reliability and cost-efficient[37] electricity delivery are necessary. These investments have to cover the electricity generation at times of low wind speed and should be able to run at lower activation levels at high wind speed. The backup of wind power on the long term can therefore best be seen as a *capacity margin* issue [17; 35; 97; 99].

The capacity credit[38] of wind tells how much wind contributes to electric power generation in function of its installed power. Even with a perfect forecast, wind energy will not contribute in the same way that a conventional power plant does, exactly because of its variability and lower availability on an annual basis. It might be necessary to use more than one year’s data to look at the impact of wind power integration on the system. Wind power has to be reliable not just for one year. Both average reliability and worst case events provide information on the consistent value

[36] To a lesser extent, the unpredictability is also related to the investment in power in the sense that investments are sometimes needed for offering short term balancing options.

[37] Depending on the objectives in electricity generation, externalities such as GHG emissions should be included in the cost calculations.

[38] The capacity credit of a wind turbine is explained in more detail in chapter 7. In short, it can be described as the contribution of wind power to system capacity.

of wind power on the long term. The capacity credit is also linked to the long term investment issue of wind power in the sense that it determines the value of wind under unchanged reliability levels. It is the concept that is used to compare wind power capacity to firm conventional capacity. The capacity credit and adequacy evaluation of wind is further covered in section 4.3.

4.1.3 Backup capacity

Confusion exists on the term "backup capacity" since it can refer to both supporting capacity for power and energy requirements [100]. In [100], backup capacity refers to the conventional power plants that are needed to supply electricity when wind power is unavailable. It refers to the capacity needed for covering the potential loss of energy supply from wind power. For moderate amounts of installed wind power, the energy supply of wind power does not need backup energy. The contribution of wind power to firm capacity on the other hand is more problematic. Wind turbines cannot guarantee capacity the same way as conventional power. In this thesis, wind power backup capacity relates to the amount of instantaneous power needed to cover for wind power being unavailable at some moment in time.

4.2 Unit commitment and dispatch modelling of electricity generation systems

This section describes the Mixed Integer Linear Programming (MILP) model used for unit commitment (UC) and dispatch of the electricity generation system. This two-phase model allows for the simulation of the operation of electricity generation systems applying the relevant technical boundaries, fuel cost and emission factors.

The model is written in GAMS and Matlab, using the Matlab/GAMS link [101-103]. The optimisation in GAMS uses the Cplex 10.0 solver [104]. Excel is used to structure the data and serves as input for the modelling. The model has been developed at the K.U.Leuven, at the division of Applied Mechanics and Energy Conversion by Delarue [105; 106]. It is based on previous research performed in [107; 108]. A schematic overview of the model is depicted in Figure 11.

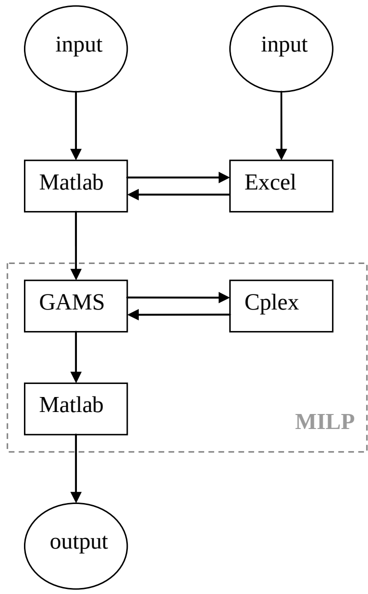

Figure 11: Schematic overview of the MILP UC/dispatch model [106].

4.2.1 MILP unit commitment/ dispatch model structure

The MILP model is set up in a two-phase approach. Every simulation run models a 24 hour day hour-by-hour. In the first phase, the UC, in the narrow sense, is performed. The demand for every hour needs to be met and a specified amount of power reserves is foreseen.

During UC, some uncertainty remains regarding the actual electricity demand. At the UC phase, the expected wind power output is based on forecast. The units in the electricity generation system are assigned in a way that sufficient generation is available at all times. Since this phase decides whether a power plant is operational or not, a mixed integer optimisation approach is used, allowing the units to get a "0" or "1" assigned. The problem is solved for 24 hours, thereby taking into account the technical characteristics of all the active elements. These include minimum up and down time, maximum contribution to power reserves, efficiency at different activation levels and ramp rates. The data are gathered from several utilities and [109]. The activation levels, as represented in Figure 12 of a power plant deserve some extra attention. Typically a power plant has a nominal power output, representing its maximum power (Pmax) and a minimum point of operation (Pmin). Between these two extremes, different activation levels are possible. Each activation level has a certain constant marginal cost (MA and MB in Figure 12). The amount of electricity generated in a power plant also determines its final operational efficiency.

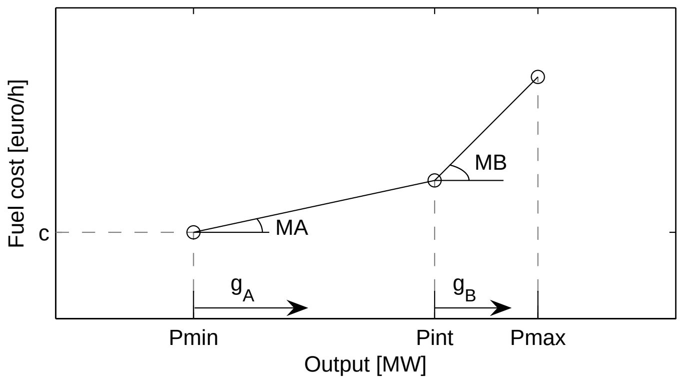

Figure 12: Stepwise cost function of power plant with two activation levels between minimum and maximum power [106].

The dispatch of the system is done in the second phase for each of the 24 hours individually. Since the generation units have already been committed in the UC phase of the model, the dispatch only needs to define how these units are optimally used under perfect information. This has as consequence that the problem is reduced to 24 separate linear programming optimisations. At this time the actual wind power output is known. The forecast error of the wind power output is the difference between the forecasted electricity generation in the UC phase and the actual output at dispatch. In a first instance, the dispatch is a linear cost-based minimisation problem. In the occurrence of insufficient generation capacity in a particular hour to meet both demand and reserves requisites, a second optimisation is performed. This second optimisation relaxes the reserves requirements and solves the problem under reserves maximisation. Fewer reserves being available in the system, has a direct impact on the reliability of the system, as described in [110].

A schematic overview of the UC/ dispatch algorithm is presented in Figure 13.

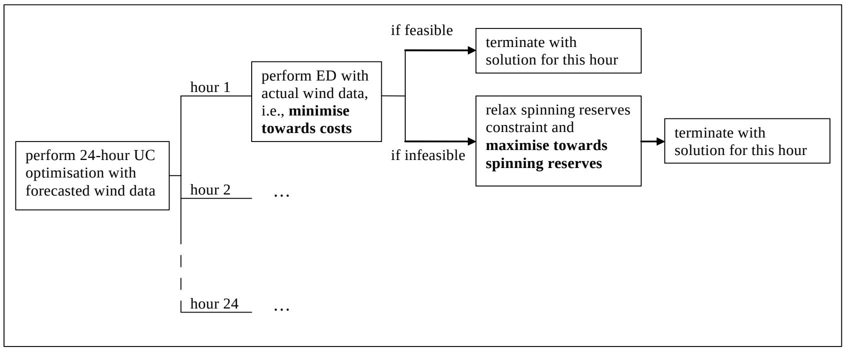

Figure 13: Overview of the 2-phase algorithm with two dispatch options [111].

The optimisation function is based on cost minimisation. The fuel costs constitute the most important input for this function. For the simulations presented here, the fuel prices are based on the International Energy Agency (IEA) World Outlook prices of 2005 [112]. Without the inclusion of a CO_2-price, coal-fired power plants are the cheapest option after nuclear plants[39]. Gas-fired power plants, especially the efficient combined cycle power plants, are also used extensively due to their flexible operating characteristics. These can easily adjust to changes in supply and demand. Smaller plants such as gas turbines and diesel engines are used for temporal needs, mostly to cover short-term peaks in demand. They offer more flexibility to the system.

4.2.2 Optimisation function and main constraints

4.2.2.1 List of symbols in the optimisation model

Sets

I set of power plants (index i);

J set of time periods (index j).

Parameters

c_i fuel cost at minimum output of plant i [€/h];

d_j electricity demand in period j [MW];

[39] The actual prices are of less importance than the ratio between them. The focus in the analyses described in what follows is not so much on the overall fuel cost than on the effects of the use of different fuels.

MA_i	marginal fuel cost of first part of plant i [€/MWh];
MB_i	marginal fuel cost of second part of plant i [€/MWh];
mdt_i	minimum downtime of plant i [h];
mut_i	minimum uptime of plant i [h];
$Pmin_i$	minimum output of plant i when committed [MW];
$Pint_i$	intermediate output of plant i [MW];
$Pmax_i$	maximum output of plant i [MW];
$Resdemand_j$	power reserves demand in period j [MW];
$Resmax_i$	Maximum contribution to power reserves from plant i [MW].
S_i	start-up cost of plant i [€];

Variables

Cost	total cost of electricity generation [€];
Fuelcost(i,j)	fuel cost function of generator i in period j [€];
g(i,j)	actual electricity generation of plant i in period j [MW];
$g_A(i,j)$	electricity generation between Pmin en Pint [MW];
$g_B(i,j)$	electricity generation between Pint en Pmax [MW];
r(i,j)	share of generation assigned to reserve provision [MW];
Startupcost(i,j)	start-up cost of plant i in period j [€];
z(i,j)	indicator indicating whether unit i is committed or not in period j: 1 if committed, 0 if not.

4.2.2.2 Unit commitment

Objective function

The objective function of the UC problem is represented by a cost function that needs to be minimised. Summing up over all time periods and all power plants, the fuel and startup costs are to be minimised. Equation (4.1) presents the objective function in the case of a single node[40] problem:

$$\min\left(\sum_{i,j} Fuelcost(i,j) + \sum_{i,j} Startupcost(i,j)\right) \tag{4.1}$$

Index i corresponds to the set of power plants, while index j corresponds to the set of time periods, in this case one hour periods.

[40] A dc load flow can be used for solving multi-nodal problem, with a different set for different nodes.

Constraints

Equation (4.2) represents the obligation of all electricity generation over all units to cover the demand.

$$\forall j \in J: \quad \sum_i g(i,j) \geq d_j \tag{4.2}$$

The power reserves constraint is represented in the same way as:

$$\forall j \in J: \quad \sum_i r(i,j) \geq Resdemand_j \tag{4.3}$$

With assigning of power reserves occurring according to following constraints:

$$\forall j \in J: \quad r(i,j) \leq z(i,j) \cdot Resmax_i \tag{4.4}$$

$$\forall j \in J: \quad r(i,j) + g(i,j) \leq Pmax_i \tag{4.5}$$

The fuel cost constraint can be written as:

$$\forall i \in I, \forall j \in J: \\ Fuelcost(i,j) = c_i \cdot z(i,j) + MA_i \cdot g_A(i,j) + MB_i \cdot g_B(i,j) \tag{4.6}$$

To properly model the stepwise cost function of a power plant with its different activation levels, the following constraints are used in the optimisation problem. The variables z(i,j) are binary variables, referring to their values being restricted to either *0* or *1*. Equation (4.7) defines the total generation of a power plant i in period j to depend on the minimum operation point and the different activation levels:

$$\forall i \in I, \forall j \in J: \quad g(i,j) = g_A(i,j) + g_B(i,j) + Pmin_i \cdot z(i,j) \tag{4.7}$$

Equations (4.8) and (4.9) assign the electricity generation to the different activation levels:

$$\forall i \in I, \forall j \in J: \quad g_A(i,j) \leq \left[Pint_i - Pmin_i\right] \cdot z(i,j) \tag{4.8}$$

$$\forall i \in I, \forall j \in J: \quad g_B(i,j) \leq \left[Pmax_i \text{ - } Pint_i \right] \cdot z(i,j) \tag{4.9}$$

The startup cost of a power plant is defined by Eq. (4.10) and depends on whether a power plant i is activated in period j.

$$\forall i \in I, \forall j \in J: \quad Startupcost(i,j) \geq S_i \cdot \left[z(i,j) - z(i,j-1) \right] \tag{4.10}$$

To include minimum up- and downtimes, the following constraints are constructed [41]:

$$\forall i \in I, \forall j \in J, \forall k \in [1,2,...,mut_i - 1]:$$
$$\left[z(i,j) - z(i,j-1) \right] + \left[z(i,j+k-1) - z(i,j+k) \right] \leq 1 \tag{4.11}$$

$$\forall i \in I, \forall j \in J, \forall k \in [1,2,...,mdt_i - 1]:$$
$$\left[z(i,j-1) - z(i,j) \right] + \left[z(i,j+k) - z(i,j+k-1) \right] \leq 1 \tag{4.12}$$

Equation (4.11) ensures that once a power is switched on, it remains so for a given time. Equation (4.12) makes sure a plant remains offline long enough after it is switched off.

Additional constraints are put on the variables:

$$\forall i \in I, \forall j \in J: \; g_A(i,j), g_B(i,j), Startupcost(i,j) \geq 0 \tag{4.13}$$

$$\forall i \in I, \forall j \in J: \; z(i,j) = 0 \text{ or } 1 \tag{4.14}$$

4.2.2.3 Dispatch

For every period to be modelled, the dispatch optimisation is run. Every period j needs to be in balance. In practice, 24 runs are performed for each UC / dispatch problem. As explained above, in the case the solver is not able to comply with the

[41] For the first and last time periods of a simulation, adaptations of these equations are made to allow for a solution with a certain power plant online in the last time periods for a number of hours lower than its minimum uptime.

power reserves constraint, an alternative dispatching occurs. This optimisation is not under cost minimisation but under reserves maximisation.

Objective function

The objective function of the dispatch problem under cost minimisation is represented in Eq. (4.15). For a given period j, the fuel costs need to be minimised.

$$\min\left(\sum_i Fuelcost(i)\right) \tag{4.15}$$

Alternatively, if the maximum reserves dispatch is used, Eq. (4.16) becomes the objective function

$$\max\left(\sum_i r(i)\right) \tag{4.16}$$

Constraints

Taking into account dispatch occurring for every time step and therefore should be repeated consecutively to cover the same time span as the UC, the same constraints as in UC can be used on the dispatch phase:

$$\sum_i g(i) \geq d \tag{4.17}$$

$$\sum_i r(i) \geq Resdemand \tag{4.18}$$

$$r(i) \leq z(i) \cdot Resmax(i) \tag{4.19}$$

$$r(i) + g(i) \leq Pmax_i \tag{4.20}$$

$$\forall i \in I: \quad Fuelcost(i) = c_i \cdot z(i) + MA_i \cdot g_A(i) + MB_i \cdot g_B(i) \tag{4.21}$$

$$\forall i \in I: \quad g(i) = g_A(i) + g_B(i) + Pmin_i \cdot z(i) \tag{4.22}$$

$$\forall i \in I: \quad g_A(i) \leq \left[Pint_i - Pmin_i\right] \cdot z(i) \tag{4.23}$$

$$\forall i \in I: \quad g_B(i) \leq \left[Pmax_i - Pint_i\right] \cdot z(i) \tag{4.24}$$

$$\forall i \in I: \ g_A(i), g_B(i), Startupcost(i) \geq 0 \tag{4.25}$$

$$\forall i \in I: \; z(i) = 0 \text{ or } 1 \qquad (4.26)$$

4.2.3 Reliability assessment using the UC / dispatch model

The MILP model also allows for a simplified reliability assessment to investigate how the volume of power reserves determines the loss of load probability (LOLP) [110]. The LOLE for a year is determined aggregating the LOLP over the 24 hours and multiplying by 365 to get an approximated value. It is based on Eq. (2.1).

To keep track of the LOLP in the model, the cumulative outage probability of a certain size X is determined using following recursive Eq. (4.27) [65]:

$$P(X) = (1-U)\cdot P'(X) + (U)\cdot P'(X-C) \qquad (4.27)$$

P(X) refers to the outage probability of size *X* after the inclusion of a certain unit with capacity *C* and a forced outage rate *U* in the system. *P'(X)* determines this probability before the addition of the unit.

The cumulative outage probability of an amount exceeding the available power reserves during one specific hour can be calculated according to this method. This probability is the LOLP for that specific hour.

4.2.4 The Belgian electricity generation system

An important element in the simulations using the MILP model is the composition of the electricity-generation system under consideration. The Belgian electricity generation system has been modelled for this purpose. An overview of the main characteristics of the applied Belgian electricity generation system is given in Appendix A.

The electricity generation system is roughly composed of three major groups of power plants. The nuclear power plants, which have a high utilisation factor, provide base-load power and make up about 60% of all generated electricity. The second group consists of coal-fired thermal power stations. Their utilisation factor under the considered reference fuel prices, as introduced in section 4.2.1, is relatively high due to the relative low cost of coal. The third group comprises the gas-fired combined cycle units. Because of their high efficiency and modulating capacities they are frequently in operation. Apart from these main blocks of power generation, Belgium had a limited installed capacity of renewable energy because of the unfavourable conditions and corresponding low potential for renewables.

Cogeneration is a technology that is rapidly gaining ground in the Belgian electricity-generation system. Belgium also has pumped hydroelectric storage (PHES) units of about 1300 MW in Coo and Silenrieux that enable more efficient operation of base load electricity generated off-peak which can be stored to meet peak demand.

4.2.5 Typical wind speed and demand profiles

In the analyses performed further on, specified wind speed and demand profiles are used. They are chosen so as to represent diverging situations of wind power output and demand.

Four different wind speed profiles, *Windday A* to *D*, are chosen to represent typical patterns in wind power output during a day. They originate from actual data of the Belgian Meteorological Institute, which are measured at a 10 m altitude and extrapolated to 80 m data applying the logarithmic law as explained in section 1.6.1. The transformation from wind speed to wind power is based on the Vestas V80 wind turbine power curve according to the method described in section 1.6.2. The profiles that are applied in the MILP model, depicted in Figure 14 and also used in [113], represent the fluctuating behaviour of wind. The corresponding wind power profiles for the four wind speed profiles applied to the 2 MW Vestas V80 wind turbine power curve, is depicted in Figure 15. *Windday A* represents a situation with low wind speeds. *Windday C* stands for a high overall wind speed profile. *Winddays B* and *D* have average wind speeds, with the former having its peak in the morning and the latter in the evening.

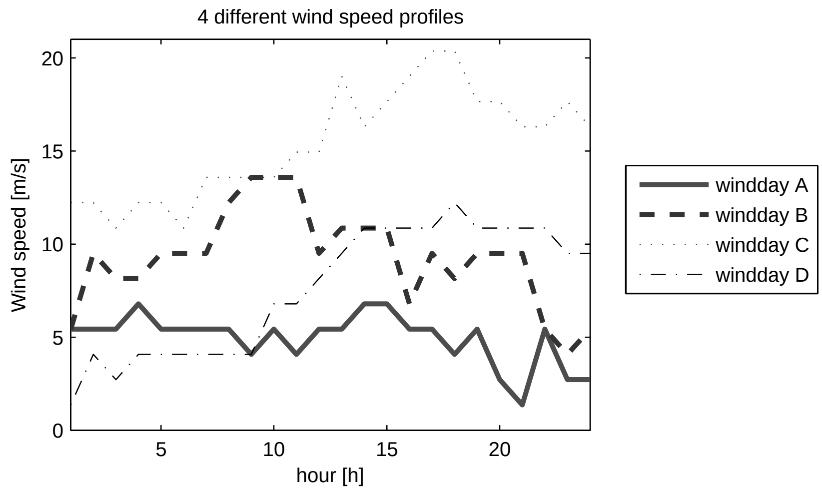

Figure 14: Wind speed profiles of 4 different days, showing typical fluctuations [12]

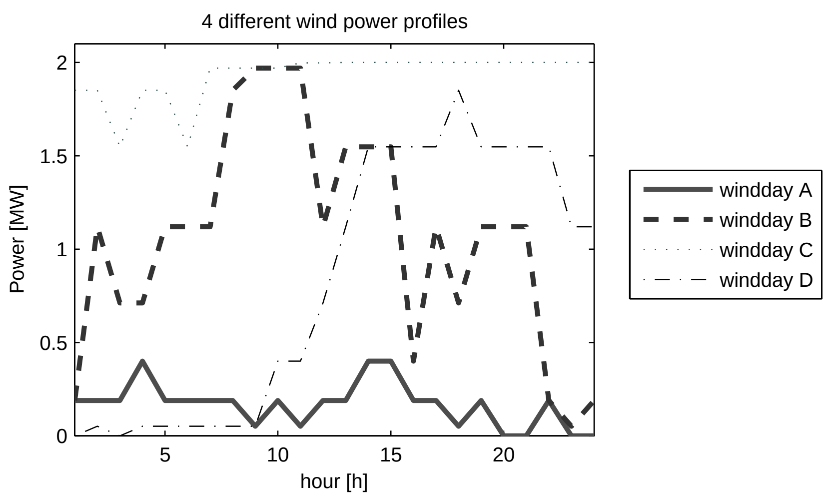

Figure 15: Wind power profiles corresponding to the 4 wind speed profiles, assuming a 2 MW Vestas V80 turbine for the power generation

Four electricity demand profiles, *Day 1* to *4*, have been selected as well. These are shown in Figure 16 and are taken from actual 2006 demand data from Elia, the

Belgian transmission system operator (TSO) [114]. They are chosen as to represent distinct demand situations and have been used also in other studies by the author [110; 113; 115]. It has to be observed that Elia deducts the electricity originating from decentralized generation units, such as combined heat an power installations, from its demand data. Moreover, Elia's control area includes more than only the Belgian territory. The Sotel grid in the south of the Grand-Duchy of Luxemburg is also part of Elia's control area.

The demand profiles in Figure 16 range from a high overall demand in *Day 1* to a low demand profile in *Day 4*. All have the typical peaks in demand around noon and in the evening. *Day 1* and *2* are typical winter profiles, with the former being situated in the weekend. *Day 3* and *4* are summer demand profiles, of a weekday and weekend day, respectively.

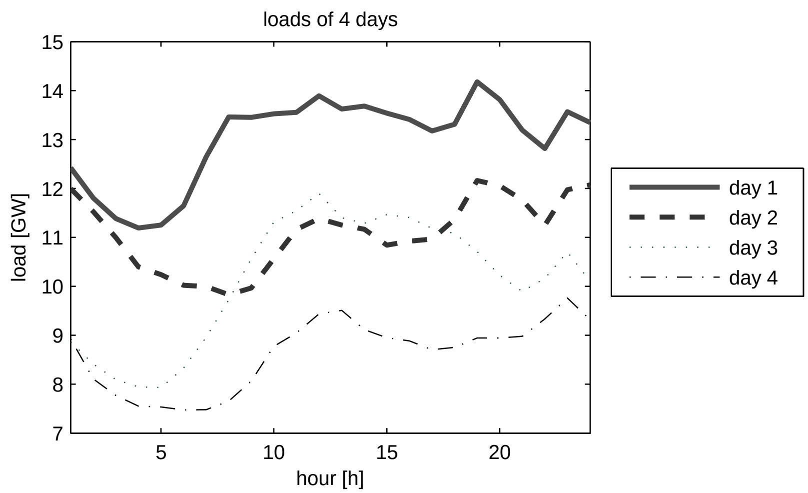

Figure 16: Demand profiles of 4 different days based on actual 2006 demand data of Elia [114]

The wind speed and demand profiles are repeated on the last page of the thesis, for an easy reference.

4.3 Reliability assessment model of an electricity generation system

Whereas the MILP model can be used as a tool for short term study of wind power integration in an existing electricity generation system, a different approach is applied for long term investigation of the impact of wind power. As mentioned above, on the long term not the operation but the system design becomes important. The adequacy of the system with increasing wind power integration needs to be evaluated. This makes an evaluation of necessary investments in the system to better cope with the changes occurring through wind power installations possible.

This section presents a tool for the calculation of four different adequacy indices. Each one of these indices evaluates the adequacy of the electricity generation system viewed from a different angle. An adapted IEEE reliability test system is used for this purpose. To allow for the analysis of wind power in the test system, Markov matrices are used to generate wind speed data to be used as input in the Monte Carlo simulations of the system.

At a later stage, in Chapter 7, the described model will be used to evaluate wind power investments under different circumstances and to calculate the capacity credit of wind power.

This section begins by introducing the concept of Markov chains and matrices. In the second subsection, the model itself is explained.

4.3.1 Markov matrices for wind speed

The principle of Markov chains is used to generate wind speed data as input for the reliability evaluation process. The principle of Markov chains and matrices has already been used previously as a proven method for statistical analysis of wind speed [116-118]. In this analysis, a new parameter, distinguishing between day and night and summer and winter, is added to the analysis. A Markov chain states that the probability distribution at time t+1 depends on the state at time t and not on the states the chain passed through before getting to time t [119][42]. This has as a consequence that the state at one moment in time is stochastically dependent on the

[42] Implicitly, the state at time t+1 is dependent of the states at previous times through the dependency of the state at time t with the state at time t-1. However, all the information on the previous states is already incorporated in the information of state t. No additional linkage to states, other than the one at time t, is necessary to define the state at time t+1.

previous state. The transition between two states can be expressed by a transition probability matrix. Based on historical wind speed data, it is possible to define the transition probability of wind speed [12; 116]. This gives for a given wind speed at time t, the probability for each wind speed at time t+1.

To generate an unrestricted number of wind speed profiles as input for the Monte Carlo based calculation of the adequacy indices, as explained in the next section, Markov matrices are created for every hour of the year. These define, for every possible wind speed at time t, the probability of having a certain wind speed at time t+1.

Examples of such a matrix for the first and the 4400th hour of the year are found in Appendix B. Each hour has a slightly different matrix, depending on the time during the day and the season. The wind speed transition probability matrices are normalised to make the sum in each row equal to 100% thereby leading to *first order Markov matrices*.

The statistical properties of 12 years of wind speed measurement in Middelkerke, at the Belgian coast, obtained from the Belgian Meteorological Institute are used for this purpose [12]. Firstly, a distinction is made between a summer and a winter season, while at the same time differentiating between day and night wind speeds. For each of these four combinations a wind speed transition matrix is constructed. These are then interpolated between one another to obtain a matrix for each hour of the year. The shape of the day-night profile followed for interpolation is depicted in Figure 17 for both the winter and the summer season. It represents the 24 hour evolution of the probability of having 5 m/s next hour when this hour a 4 m/s speed is registered. These winter and summer profiles are linearly interpolated to get a different evolution of probabilities for every day of the year. The resulting 8760 Markov matrices reflect the properties of the season and day-night difference. Figure 18 gives an impression of the Markov matrices for the month of May, with the transition probabilities to have a wind speed of 5 m/s in hour h+1 if hour h has a 4 m/s wind speed. Figure 19 and Figure 20 graphically represent the wind speed transition probabilities of a switch from one value in the first hour to the second hour and from the 4400th hour to the 4401 hour respectively, corresponding to the graphical representations of Appendix B.

It has to be noted that, although the probabilities of having the same wind speed of time t at time t+1 are the largest, it is always possible to see a considerable change in wind speed between two hours. This is visualised in Figure 19 and Figure 20, where the highest transition probabilities clearly lie on the diagonal, representing the probability of a status quo for wind speed. However, the probabilities of having wind speed transitions that do not lie on the diagonal and that represent changes in wind speed between two hours are still significant. Towards the higher wind speed values, higher off-diagonal probabilities are registered, indicating more frequent changes in wind speed between two consecutive hours.

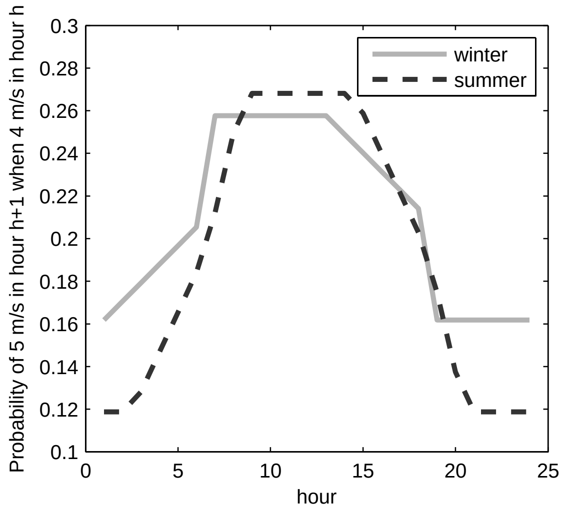

Figure 17: Evolution of the probabilities of having 5 m/s wind speed in hour h+1 when given that hour h has a wind speed of 4 m/s for both summer and winter. Relationships like these exist for every transition from one wind speed to another within the time span of an hour.

Using the wind speed transition probabilities of the Markov matrices, wind speed data can be generated with similar statistical properties to the original wind speed data. Average values, variability of the data and both day-night and seasonal differences are incorporated in the generated values. The data are used as input for the Monte Carlo analyses of the reliability of the electricity generation system.

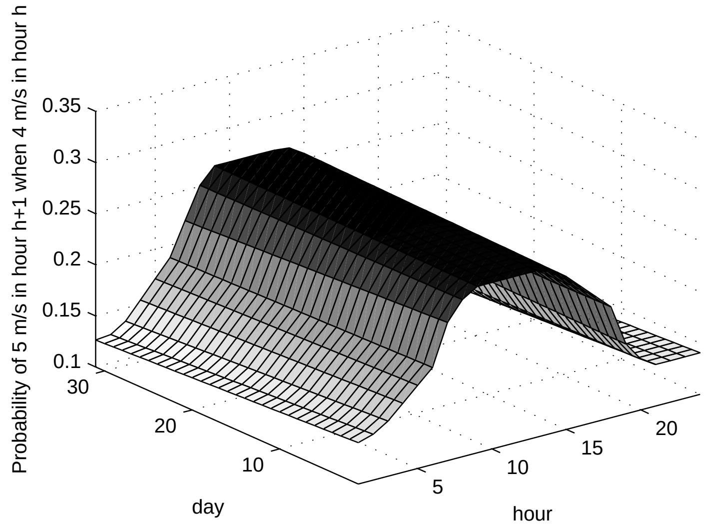

Figure 18: Evolution of the probabilities of having 5 m/s wind speed in hour h+1 given that hour h has a wind speed of 4 m/s for the month of May.

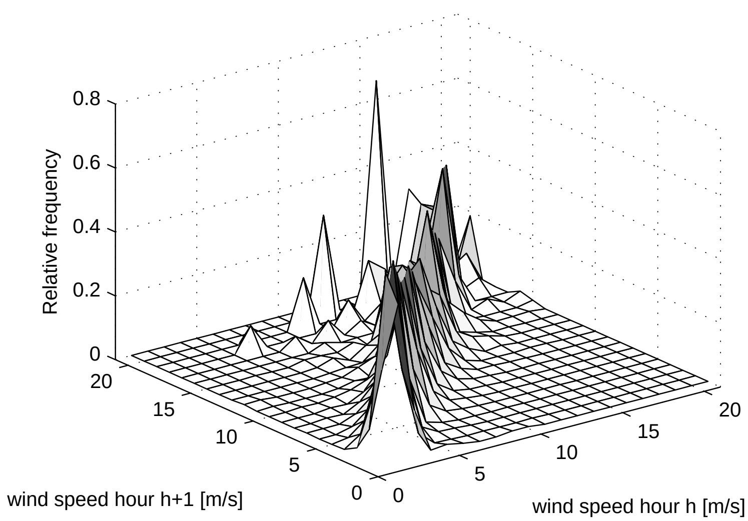

Figure 19: Markov transition values for the first to the second hour of the year.

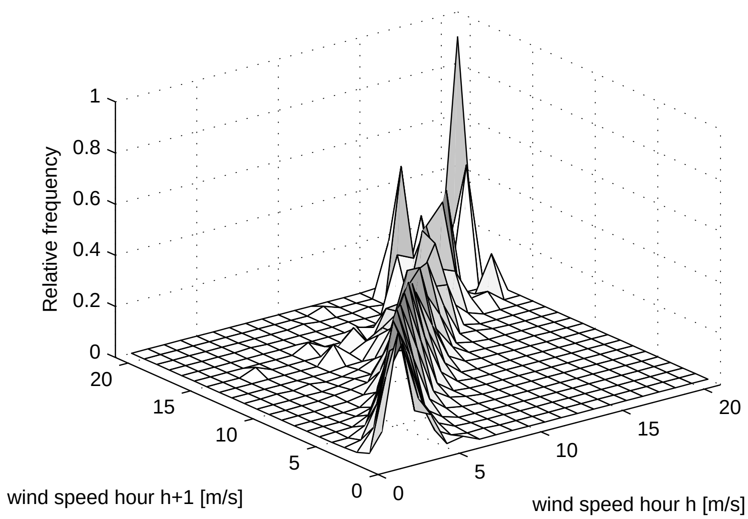

Figure 20: Markov transition values for the 4400th to the 4401st hour of the year.

4.3.2 Adequacy evaluation model

To establish the various adequacy indices of electricity generation systems with and without wind power, a sequential Monte Carlo approach is used, referring to the chronological structure of the approach[43]. This method simulates different years and calculates the adequacy parameters, Loss-of-load expectancy (LOLE), Loss-of-energy expectancy (LOEE), Loss-of-load frequency (LOLF) and expected interruption cost (EIC) for each year until the simulations converge to a specified extent.

For each year, the hourly states of the electricity generation system are determined. These states depend on predefined demand, random events and the operation of the system.

Two types of random events can occur. Firstly, a system component can have a certain state, depending upon the technical characteristics of that component. Each

[43] A Monte Carlo simulation is a computational algorithm that repeatedly computes results through random sampling of the input parameters. These parameters' statistical properties define the probabilities of being sampled.

generation unit or transmission line is attributed a certain failure probability and time to repair. Generation units also have a certain amount of time allocated for scheduled maintenance. These parameters define the probability of a system component being available or not. Secondly, with the addition of wind power in the system, a random wind power output is obtained for every hour of the year, based on wind speed data generated with the Markov matrices.

A simulation run determines the electricity generation and merit order for each hour, calculates the cost of generation and load not being served and how the electricity is transported in the grid for multiple years. Each year is a sample in the Monte Carlo analysis. The adequacy indices are computed for each year as well. The number of simulation years depends on the convergence of the variance of the LOEE towards a certain upper limit. This ensures that the number of simulation years or samples is sufficient to generate consistent average values for the adequacy indices and other parameters.

4.3.2.1 Structure of the reliability evaluation model

At the beginning of each simulation run, the maintenance schedule is determined so as to preserve the highest possible margin between demand and remaining available capacity, which means the largest generation units are in maintenance at the lowest demand periods in a year [65]. At the beginning of each year, random normally distributed values, taking the probabilities of unexpected unavailability into account, are generated to simulate component failure in the system. An example of the relation between demand on the one hand and available power with maintenance planning and unscheduled outages on the other, for one year, is given in Figure 21.[44]

The electricity delivery options differ for each hour. Not only the component failure but also the wind power output is different for each hour. Given the demand, available capacity and wind power output, generation power is attributed in the system, according to the economic stacking of power plants based on their marginal cost. The merit order of the power plants determines which generation capacity is assigned to a certain demand. In the case of a deficit in generation capacity, load can be shed. Load is shed at the busses where least damage is done in terms of

[44] It has to be noted that the demand profile applied in the IEEE '96 Reliability test system, does not correspond to demand profiles in most Western European countries, as can be observed from the peak in demand during summer. In regular Western European demand profiles, the summer corresponds to a low in demand, leading to most of the large maintenance efforts being undertaken during summer.

economic consumer costs, according to set values of acquiring electricity on each bus.

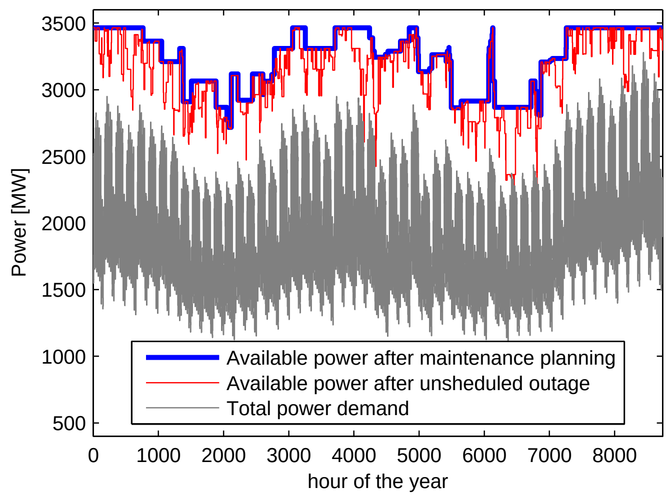

Figure 21: Available power after maintenance planning and after unscheduled outage, in correspondence with the total power demand for each hour of a simulated year. Example for the simulation of one year with 60 MW installed wind power. The demand profile is taken from the IEEE '96 Reliability test system, described in section 4.3.2.2.

Next, a *DC-powerflow* calculation is performed applying the MATPOWER code [120]. A DC formulation assumes branch resistance to be negligible, all bus voltage magnitudes to be close to 1 p.u. and voltage angle differences to be small. Only the active power flows are calculated. Using the abovementioned assignation of capacity, based on the merit order, as the real power injections in the system, the powerflow calculation determines whether the transmission lines can be used within their technical boundaries.

In the case of an overload of the grid, which occurs less than 1% of the time with the chosen system, an *optimal powerflow* is performed, still using MATPOWER. This means that loads are now re-dispatched taking into account the real power flow limitations of all lines, thereby optimising both the generation and grid transportation. The optimal powerflow is solved using linear optimisation and defines the cost-optimal electricity delivery within the set boundary conditions. Shedding of load occurs only when necessary and as cost-efficiently as possible, shedding load on lower valued busses first.

The shedding of demand at certain busses can be classified according to three causes, namely an overall deficit of generation power, the loss of a connection to the high voltage grid or overloads that cannot be overcome by rearrangement of generation capacity. Finally, the reserve provision capacity of the system during the simulated hour is examined. This entire process is repeated for every of the 8736[45] hours in a year. For each simulated year, the reliability indices are calculated. The loss-of-load events, which determine these indices, have their origin in both generation and grid shortcomings and failures.

4.3.2.2 Adapted IEEE reliability test system

As a basis system for the described analysis, the "IEEE Reliability Test System – 1996" is used [121], as represented in Figure 22. Some modifications are made to the original IEEE Reliability Test System, however. The system design and demand function are taken to be the same as the IEEE system, with the exception of an additional line between bus 7 and 8, to ensure n-1 security of the system. Moreover, an update of the generation units is done for the system, with the introduction of turbojets, gas turbines and gas-fired combined cycle power plants to the detriment of oil-based power plants. The system has 3405 MW of installed power.

The technical specificities and availability data of the power plants are taken from [109; 122]. Other technical parameters such as maximum capacity, power plant contribution to reserve and probability of line failure and time to repair are still based on the original test system data [121]. Cost data, necessary for the determination of the merit order and optimal power flow are taken from [123]. Bus outage costs, necessary for the determination of the EIC are based on [72].

4.3.2.3 Calculation of adequacy indices

The various indices are calculated as an average of the values found for every simulated year[46]. The LOLE is the average over all the loss-of-load duration; the LOEE is the average of all the energy not supplied; the LOLF is the average of all the occurrences of loss-of-load events. The loss-of-load duration (LOLD) can, through

[45] An entire year is taken to be composed of exactly 52 weeks and therefore has 8736 hours, instead of the classic 8760 hours.

[46] The concept of adequacy indices has been introduced in section 2.1.1. The indices are calculated and used in chapter 7.

interpolation of the bus cost function, lead to the cost of each interruption. Multiplying this with LOEE/LOLD gives the EIC in €/year.

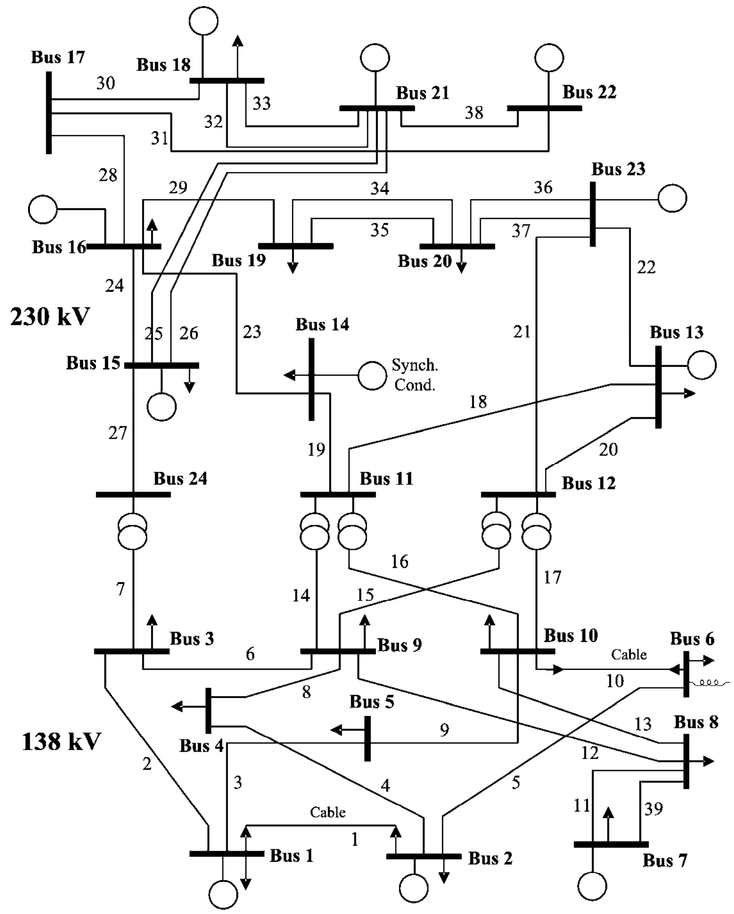

Figure 22: Schematic representation of the reliability test system, used for the reliability analysis. Some modifications are made compared to the IEEE reliability test system, where the system is based upon [121].

4.4 Conclusion

This fourth chapter can be seen as a transition chapter between background issues and in-depth analyses performed in parts 2 and 3 ahead. Firstly, the distinction is made between backup of wind power on the short and long term. Next, two models used in the following chapters for assessment of different cases, are introduced. Both models are developed and used within the K.U.Leuven, at the division of Applied Mechanics and Energy Conversion. The composition of the Belgian electricity generation system, often used as a basis for analyses, and the typical wind speed and demand profiles, used throughout the thesis, are also introduced in this chapter.

The first model is a unit commitment – dispatch model, allowing for a detailed simulation of the operation of an electricity generation system during one day. It takes a multitude of technical and cost-related characteristics into account. It is solved using a two-step approach. In a first instance, a mixed integer linear programming optimization is performed to simulate the unit commitment of 24 hours. This is based on the information at hand at the moment of unit commitment. Afterwards, a regular linear programming optimization is carried out, with perfect information on generation and demand. The model can be used for a wide variety of analyses, ranging from operational cost impact of a certain measure, to the greenhouse gas emissions reduction potential of a specific change in generation capacity.

The second model is used for reliability assessment of an electricity generation system. It is used with an adaptation of the IEEE ’96 Reliability Test System. The novelty of the applied approach is the combination of different elements, such as the calculation of four different adequacy indices, the application of Monte Carlo simulations for determination of an average outcome and the use of Markov matrices to generate an unlimited amount of wind speed time series. The Markov matrices are constructed such that day-night and seasonal differences are taken into account, thereby closely following the statistical properties of actual annual wind speed time series. The model is structured such that the loss-of-load events are kept track of. Every occurrence of a loss-of-load event that can emerge from several causes, is counted and used for the determination of the adequacy indices. In chapter 7, this model is used to determine the capacity credit of certain amounts of wind power.

PART 2

Backup of wind power on the short term

5. UNPREDICTABLE WIND AND FORECASTS

To a certain extent wind behaves in an unpredictable way on the short term. Wind speed forecasts are rarely entirely accurate and there is always a need for balancing of the forecast error. This chapter deals more closely with the balancing of wind power in electricity generation system on the short term[47]. In a first section, the balancing during unit commitment and dispatch phase is described. Next, an examination of how the system and its power plants can offer backup, with particular attention to power reserves, is performed. Then, the concept of imbalance charges by the transmission system operator (TSO) is introduced and compared for different countries. Subsequently, the comparison is made between the 2005 and 2006 imbalance charge rules in Belgium. Finally, a conclusion is given at the end of the chapter.

5.1 Balancing in unit commitment and dispatch phase

Looking more into detail at this operational component of backup for intermittent electricity sources, a distinction can be made between the balancing issues during unit commitment and during dispatch. The dispatch balancing falls under the responsibility of each BRP who has to take all the measures available to maintain the balance in his perimeter. When the BRP fails in achieving this balance, the TSO compensates the imbalance to ensure the overall balance in its control area. This is illustrated in Figure 23. Before the gate closure time, the BRP operating wind power, has to take possible forecast errors on wind-generated electricity into account.

[47] As explained in section 2.2, on the short term the existing electricity generation system is considered, without allowing any investment changes.

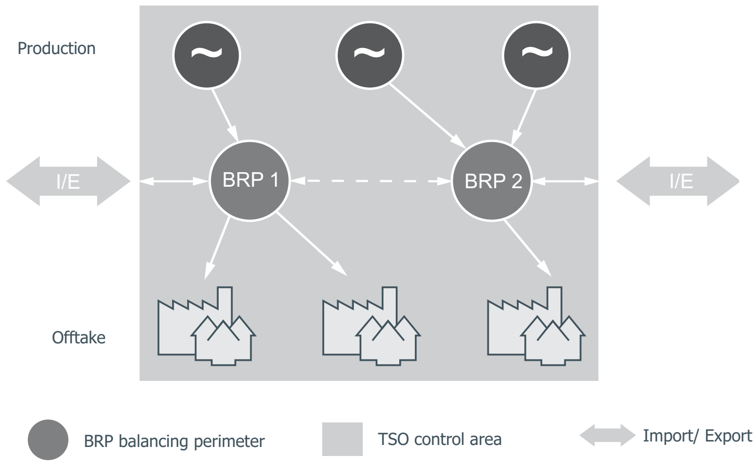

Figure 23: Balancing principle in a system. Each BRP is responsible for its own balance. The TSO compensates for imbalances that still subsist in the control area. Based on [114].

In broad terms, intermittent energy sources will usually have a combination of the following impacts on the electricity generation system and will bring about extra charges to the system [17]. Firstly, more frequent use of flexible plants with corresponding loss in efficiency will consume more fuel than without the introduction of intermittent energy sources. Moreover, keeping these plants at the disposal of reserve provision services entails an opportunity cost[48]. Furthermore, too much intermittent sources can in some situations prove difficult to be absorbed by the system, which leads to electricity from these sources being curtailed.

Additional information on the functioning of the balancing mechanism, the power reserves and balancing markets can be found in [78].

5.1.1 Reducing balancing needs

Before looking into balancing wind power on the short term through the use of reserves, a number of actions can be taken to reduce the balancing needs. Firstly, active demand-side management can offer several ways for balancing by giving impulses for shifting demand in time [124]. Demand shifting in time can be obtained through price signals. This is not to be confused with interruptible load contracts,

[48] It has to be noted that power plant operators are well reimbursed for keeping these power reserves available.

which can be used by temporarily stopping the provision of electricity to certain customers. Interruptible load contracts are an actual part of the tertiary reserves.

Another balancing solution is the cluster management operation of a wind farm as a regular power plant [25; 125]. Since cluster management entails active power limitation of wind power, one has to bear in mind that every non-usage of cheap wind power however, be it for electricity generation or reserve contribution, leads to an opportunity cost. Moreover, for individual wind turbine operators, the non-usage of wind turbines often leads to an additional loss in revenues from supporting mechanisms such as green certificates.

Through optimal usage of interconnections with other grids, a larger area can be considered as "aggregated system". For wind power, this interconnection means a more significant geographical dispersion effect. For the balancing services, this means more opportunities and options to deliver the required reserve services. The extension and operation of the interconnections between control areas will play an important role in the future operation of electricity generation systems, particularly when large amounts of installed wind power are considered.

A last option that deals with the particular case of an excess of wind-generated electricity is the simple curtailment of wind power when the generated electricity cannot be absorbed by the system. A way to avoid this curtailment of wind power, is through storage in, for example electric accumulation heating or pumped hydroelectric storage, as further analyzed in chapter 6.

5.1.2 Unit Commitment balancing

The unit-commitment balancing refers to the part of the balancing before gate closure time, during which the day-ahead unit commitment takes place. Generating units have to be appointed to cover the expected load for a given period. Since this commitment is based upon forecasts, a certain amount of reserves has to be foreseen as well.

As defined by [80], wholesale trade stops at gate closure, when BRPs need to submit their unit commitment programme to the TSO, as depicted in Figure 24. In more economic terms, the gate closure can be defined as the separating point between forward markets and centralised real time intra-day balancing markets [126]. The overall forecast error of both demand and supply determines to a large extent what the balancing requirements and costs for the system will be. The forecasts of intermittent sources such as wind power exert an important influence on the overall forecast and associated forecast error.

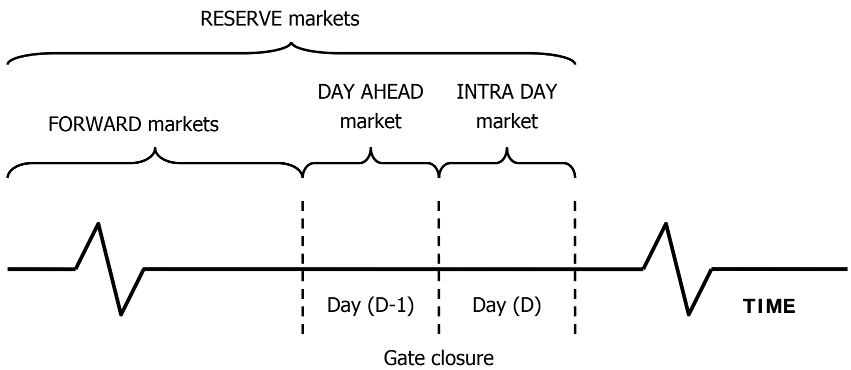

Figure 24: Relation between wholesale and real-time market and gate closure. Based on [78].

Unit commitment still falls under the short term according to the economic interpretation of short and long term since no new investments are considered. It falls under the responsibility of the power-plant operators, who have to meet the contracts with their customers.

The process of unit commitment is complicated due to the many operational constraints of generators regarding start-up and shutdown. The electricity demand is instantaneous but the decision of committing units in due time takes place well in advance. A certain security margin, consisting of units providing reserve capacity, is therefore required. Unpredicted variations in output have to be met by these reserves. The more unpredictable a system becomes, the higher this margin should be [127]. The reserves in this context refer to additional resources that can adjust their output relatively fast to absorb unexpected changes in loads and generation.

The determination of reserves is based on years of experience and mathematical models. Minimum reserve requirements have been established to meet operational malfunctionings such as sudden power plant outages[49] or failure of important transmission capacity.

[49] This is referred to as the Forced Outage Rate (FOR).

5.1.3 Dispatch balancing

The dispatch balancing takes place in the timeframe of the primary, secondary and tertiary reserve, after gate closure time [61]. Outages and unexpected unavailabilities from intermittent sources, as well as from the conventional power sources and deviation of demand from the forecasts are to be covered by the reserves available in these timeframes. According to the European Wind Energy Association (EWEA), the power balancing requirements due to wind power mainly address reserve power in secondary and tertiary control time scales [14]. This reserve power is in general offered on the balancing market.

Modest amounts of wind power development have little to no influence on the amount of primary reserves needed, especially for hydro-based systems, as concluded by some studies [30; 128]. The amount of primary reserve allocated in the power systems is dominated by outages of large thermal generation plants, thus more than large enough to cope with these very fast variations. This is only true for moderate levels of wind power. Once the amount of wind power becomes vast[50], the wind power will have an effect on primary reserve. Another story holds, for example, for large offshore wind farms. A technical failure on the transmission line connecting the farm to the grid might influence the very short term balancing of the system. Also in the event of reaching the cut-out speed of the wind turbines, a drastic change in situation, from an output at rated capacity to zero, has to be coped with.

On the scale of secondary and tertiary reserve, more backup capacity has to be kept. This is achieved by a combination of contracts with power plant operators to keep some capacity on partial load and industrial customers to allow load shedding when certain events occur. These reserves encompass the time scale where relevant changes in large-scale wind power occur. The forecasting method and gate closure time are of utmost importance to quantify the required increase in reserves. Not only should the reserve allocation and utilisation be optimised, but also the minimisation of forecast errors should be looked at.

[50] a couple of GW of installed power

5.1.4 Factors influencing reserve needs for unit commitment and dispatch balancing

The operational backup in general is driven by a wide set of factors. Investment- and country-specific issues as well as the particular operating characteristics of the considered investments in wind power will influence the reserve provision needs.

According to Dragoon and Milligan [129], the increase in reserve is assumed to be proportional to the increase in the standard deviation of hourly loads during a year, considered with and without wind power generation. The reserve requirements follow the same trend as other studies, increasing more than proportionally with the amount of installed wind power capacity. Hirst and Hild [130] confirm this conclusion. When no additional measures are taken to cover increasing amounts of wind power, more excess-energy is required and reserve-shortfall violations occur.

Several other factors influence the amount of additional reserves needed [17]. First of all, it is related to how fast intermittent sources fluctuate and what the extent of the aggregated impact on the total system will be. In addition, the accuracy of the forecasts has a very important influence on the amount of reserves required. In reality there will always be some sort of unpredictability, which makes no system or unit in the system completely reliable. Next, the correlation between existing variations in demand and the intermittent sources will define the extent of additional reserves needed. Finally, the composition of the existing reserve-delivering capacity on the system will have an impact on the reserve requirements.

Reserves are often chosen to amount three times the standard deviations of the potential uncertain fluctuations[51]. This corresponds to 99% of fluctuations being covered by reserves. Foreseeing a margin of four standard deviations will statistically result in 99.9% of the fluctuations being covered by sufficient backup capacity [17]. However, this still corresponds to about 500 minutes per year when the margin is insufficient. A more reasonable margin has about 99.9999% of the fluctuations covered and only problems during about 5 minutes per year.

According to most studies, from a certain point on, additional reserve is required in the system to absorb the wind energy [13; 17-19; 95; 130]. Milborrow refers to several studies where this point is being calculated [19]. Values range between 5 % and 15% of electricity generated by wind with most numbers situated around 10%

[51] Originating from uncertainties from demand, conventional power plants and intermittent sources.

wind-related energy penetration. In most cases, this reserve margin can be provided by existing power plants[52]. The EWEA reports estimates of extra balancing reserve requirements due to wind power around 2-8% of installed wind power capacity. This is valid for a penetration rate of 10% of gross energy provision[53] by wind power [25]. When using good forecasts, these reserve requirements are situated between 2 and 4% of installed wind power capacity. The requirements obviously lead to additional costs, which will be analysed in more detail in what follows.

5.2 Analysis of wind power integration with 100 % reserves for wind[54]

This section illustrates how in an extreme case, whereby wind power output is considered to be completely unreliable, the system must foresee a full coverage of forecasted wind power. Reserves of the same magnitude as the forecasted wind power output must then be retained during the UC phase.

The first option for balancing consists of keeping reserves available. Flexible generation units can easily be adapted to the combination of varying load and supply. New thermal units with advantageous start-up and shutdown characteristics are a logical way of balancing intermittent generation. These thermal units are mainly gas-fired. Part-load operation of power plants has to be seen in this context as well. The effectiveness of the units providing reserves depends to a great deal on their ramping rates. The faster they can adapt to changing situations, the better will they be suited for balancing reserve provision. The flexibility characteristics of fossil fuel power plants is covered in [131]. Pumped hydroelectric storage can also be seen as an effective way for balancing wind power or any other element in the electricity generation system. It is studied in more detail in chapter 6.

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[52] As soon as this does not suffice anymore, new peaking plants have to be installed. This, however, goes beyond the scope of short term treatment. As a last resort, according to Milborrow, expensive storage facilities can be built, driving the price even higher.

[53] This corresponds with values between 30 and 40% of installed wind power in the electricity generation system.

[54] This section is based on the published journal paper "Luickx, P.J., Delarue, E.D., D'haeseleer, W.D. 2008. Considerations on the backup of wind power: Operational backup. Applied Energy. 85(9), 787-799"

5.2.1 Description of the case

In the event that wind is considered to be completely unreliable, the balance responsible party (BRP) needs to foresee a backup of 100% of the forecasted wind power output[55]. This situation covers the extreme event that wind power forecasts are exceptionally erratic. Reserves must be increased just for the purpose of providing backup.

The cost for wind power backup is defined by the extra cost on the electricity generation system by imposing these reserves. In this exercise, a least cost solution of the whole system with a given demand is assumed, where the reserves costs consist of the cost of keeping extra power online. The power plants providing the reserves, consist of the regular power plants that are available in the electricity generation system. In simulating the operation of the system with this additional reserves requirement, the MILP model chooses the cheapest solutions for reserves first. No additional costs such as transaction costs are presumed.

It has to be noted that the reserves costs are to a large extent dependent on the considered electricity generation system. This case is based on the Belgian system, using the available power plants for UC and dispatch. The reserves are mostly found to be gas-fired combined cycle power plants and pumped hydroelectric storage (PHES)[56].

The disadvantage of keeping an additional coverage of reserves, representing 100 % of the forecasted instantaneous wind power, is the higher associated cost. In all probability, it will not be necessary to use all of the foreseen extra reserve. The advantage of this approach is that any shortfall in the production of electricity from wind power will always be covered by an appropriate amount of backup. The system will remain secure at all times and the reliability level, as described in section 2.1.1, will always be maintained at the required standard. Uncertainty comes into play at this point but only implicitly since any imbalance occurring due to wind power, will always be backed up by the available reserves.

The analyses are carried out for the four typical wind profiles in steps, described in 4.2.5, with the aid of the MILP model. As an additional parameter, the amount of

[55] Different terms exist to define the party responsible for the balancing of electricity generation. The term *Balance Responsible Party* (BRP) is used in this thesis. Access Responsible Party (Belgium), Balance Responsible Entity (France) or Program Responsible Parties (the Netherlands) all refer to this same concept of a BRP.

[56] PHES is further analysed in chapter 6.

considered wind power to be installed varies from 0 to 2000 MW with an interval of 250 MW. A 2 GW amount of installed wind power would coincide with about 12% of total installed capacity in Belgium.

5.2.2 Results of the analysis with 100 % reserves backup

The results for the wind profiles of *winddays A* to *D* are represented in Figure 25 to Figure 28.[57]

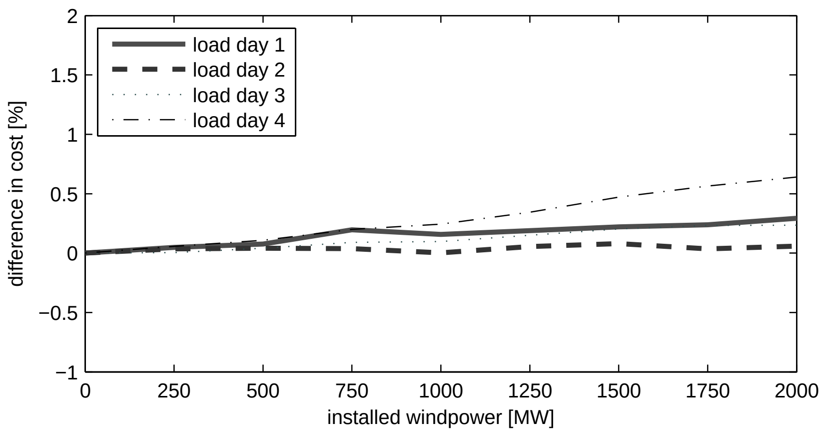

Figure 25: Relative increase in operation costs, expressed in percentages relative to a case without additional reserves, of the four different load patterns for increasing amounts of installed wind power applied to the profile of windday A.

[57] The demand and wind speed profiles are introduced in section 4.2.5 and can be consulted on the last page of the thesis for easy reference.

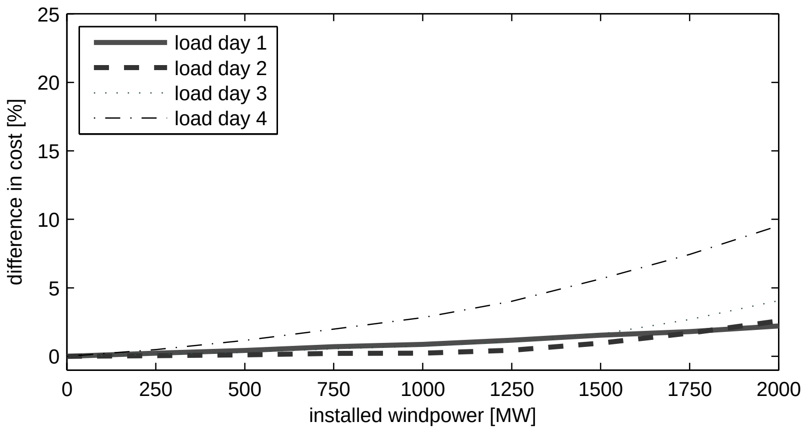

Figure 26: Relative increase in operation costs, expressed in percentages relative to a case without additional reserves, of the four different load patterns for increasing amounts of installed wind power applied to the profile of windday B.

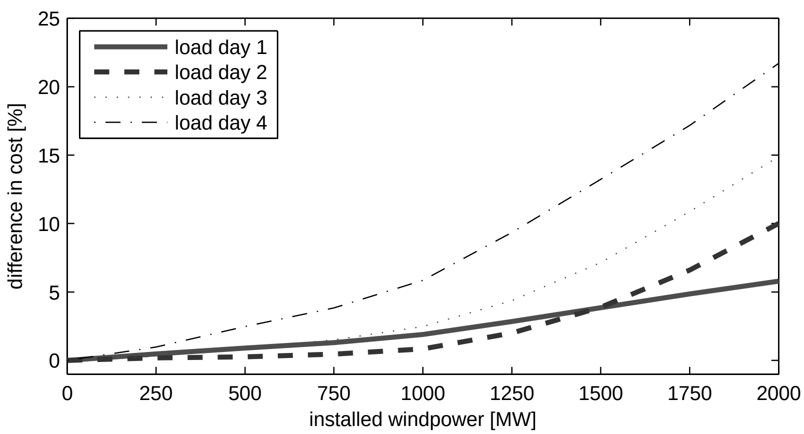

Figure 27: Relative increase in operation costs, expressed in percentages relative to a case without additional reserves, of the four different load patterns for increasing amounts of installed wind power applied to the profile of windday C.

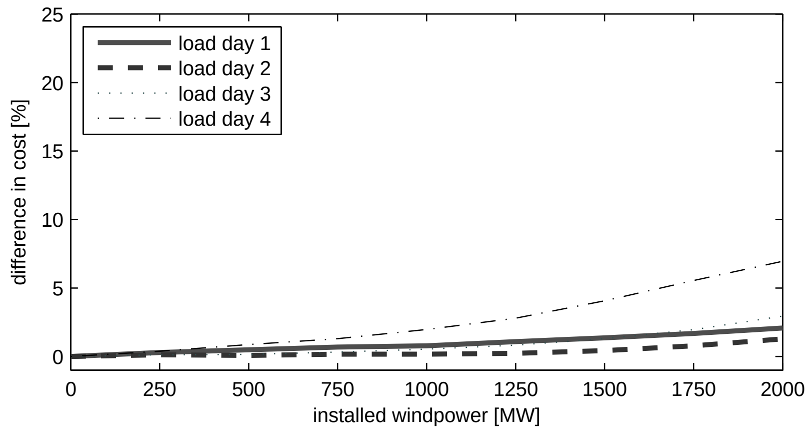

Figure 28: Relative increase in operation costs, expressed in percentages relative to a case without additional reserves, of the four different load patterns for increasing amounts of installed wind power applied to the profile of windday D.

The backup cost of wind power in this context is derived by comparing the increase in costs for the operation of the electricity generation system due to increased reserves requirements to a base case without the addition in reserves. The backup cost is thus defined by the cost for the availability of reserves. Three elements strike the eye when looking at the results.

First of all, there is a noticeable difference in cost increase between the results of Figure 26 and Figure 27. The latter has a higher overall wind power production and this translates itself in a significantly higher cost difference, going as high as 20%, where the cost increases of *windday B* only rise to about 8%. Similar results are found for the analyses of *winddays A* and *D*. *Windday A* shows practically no increase in costs due to the very low overall wind power output. *Windday D* shows results coinciding to a great extent with the results of *windday B*. For low wind speed profiles, such as *windday A*, reserves offer an interesting option. For these modest volumes of backup needs, the reserves offer a cost-effective solution since practically no additional effort from the system is needed to provide these reserves.

A second element is the fact that the cost increases with decreasing overall load during the day. The reason for this increase is that with decreasing loads, the base run where no wind power introduction takes place and no additional reserves are needed, has a lower overall cost level, mainly due to the simple fact of decreasing fossil fuel usage. The cost of reserves, being only dependent on the amount of wind power production, remains constant in absolute terms for the different load scenarios but will increase in relation to the overall base cost.

Finally, a more than linear rise in the difference cost percentage with increasing installed wind power can be discerned. The reason for the curve to become steeper as more wind power is installed is to be found in the options for reserves becoming more costly as the need for them increases. The cheapest alternatives are used first, after which increasingly more expensive options have to be drawn on leading to increasing marginal costs for the reserves. Keeping sufficient additional reserves is interesting until a certain amount of wind power is installed into the electricity generation system.

5.3 Imbalance charges[58]

This section analyses different cases of the use of imbalance charges. These are charges to be paid to or be received from the transmission system operators (TSO), depending on whether a positive or negative forecast error was made. First the concept of imbalance charges is introduced. Then different countries are compared in regard to their imbalance tariff structures. Next, after introducing the methodology for an analytical comparison of the four countries' imbalance charges with respect to wind power imbalances, the obtained results are discussed.

5.3.1 The concept of imbalance charges

Previous studies have revealed higher balancing costs for increasing shares of wind power in electricity generation systems [14; 17; 37; 132; 133]. As explained in sections 2.2.2.1 and 5.1, the BRPs are responsible for maintaining the balance in their perimeter. When they fail to do so, the TSO will compensate for imbalances with the power reserves he has at his disposal. These power reserves have to be contracted [16]. The TSO charges the BRPs for the imbalances according to the imbalance tariff rules. The costs paid for a negative imbalance or remunerations received for a positive imbalance ultimately have to be carried by the BRPs causing the imbalance. Wind power generators may become BRPs or be included

[58] This chapter is based on the submitted article "Luickx, P.J., Souto Perez, P., Driesen, J., D'haeseleer, W.D. 2009. Imbalance tariff systems in European countries and the cost effect of wind power. Submitted for review in Energy Policy."

contractually by a BRP in its portfolio. An electricity supplier can act as a BRP or designate a third party for this purpose. This BRP then has the obligation to keep the balance at its connection points and pay the stated tariffs in case of imbalance. The focus of this research lies on the transfer mechanism of system imbalance costs to the BRPs operating wind power and the impact this has on the revenue from wind power.

The operation of balancing markets is the subject of an increasing amount of studies, especially in Europe where the possible harmonisation of these markets is investigated [78; 80; 134-136]. Recent research deals with the quantification of imbalance charges for wind power producers, for different countries with different imbalance rules [34; 137-147]. The focus of this recent research lies mainly on the impact of the accuracy of the wind speed prediction tool and which bidding strategies can be taken to maximise wind power revenue[59]. The imbalance prices are calculated using simplified rules or historic time series of a particular TSO. Other research looks into ways to reduce the impact of imbalances for wind power through increasing the size of imbalance regulation zones [148; 149]. However, the dynamic character of imbalance price setting is omitted and the actual impact of the imbalance tariff rules cannot be determined. The research presented in what follows focuses on the actual imbalance rules of different countries and their impact on wind power revenues.

The cost increase for the BRP related to the imbalance payments of wind power has to be weighted off against the revenues obtained from selling the electricity from wind power on the electricity spot market at the reference market price (RMP). The total revenue of wind power depends on the type of support scheme it is subject to. Three varieties of support schemes are commonly used, namely fixed feed-in tariff, feed-in premium and green certificates. In a fixed feed-in tariff system, a fixed price is paid for each kWh of generated electricity from wind turbines. A feed-in premium system pays a fixed premium to generated electricity from wind power, on top of the regular electricity market price. In a green certificates system, the revenues from wind power are composed of sales of electricity on the electricity markets and sales of green certificates, obtained for each kWh of green electricity generated, on the certificates market. For reasons explained further in this chapter, only the regular revenues from selling the electricity on the market is taken into account. Support mechanisms are left out of the analyses.

[59] The optimal bidding strategies for BRPs not necessarily need to correspond to the best possible forecasts made.

Wind power can be considered a free-fuel power source. It will outperform more expensive fossil fuel-fired power plants. [60] The BRP incomes from selling wind power will be to some extent counterbalanced by additional costs in the operation of the system with wind power having to be integrated. These costs are passed on to the BRP through the imbalance tariffs. Exemptions to the payment of imbalance charges exists in some countries. However, no exemptions are considered in the analyses performed further on.

While every electricity generation system applies imbalance charges to some extent, each country adopts a different approach in terms of imbalance tariff structure. Verhaegen et al give an overview of the definition of balancing in European countries [83]. Some countries have single pricing tariff structures while most implement dual pricing[61]. Germany and Norway constitute examples of the former, while France, Sweden, Belgium and the Netherlands for instance apply the latter system [150]. Another price determining factor is whether average or marginal costs for imbalance reserves are charged to the BRP through the imbalance charge system.

For a closer examination of the different parameters that influence the imbalance settlement of wind power, four countries are compared, applying their respective imbalance tariff rules to different cases of wind power introduction in a given context. This allows getting an insight on the extent of costs incurred by BRPs through imbalance charges. The studied parameters can be split up in two categories. The wind power and demand related parameters make up the first category and consist of the wind speed and demand profiles and the level of installed wind power. The second category consists of parameters relating to the imbalance rules, such as the choice between marginal and average cost pricing, the extent of the penalty and other specificities for the determination of the imbalance charges that are passed on to the BRP. The latter category is controlled by policy makers, while the parameters of the former cannot be modified, in the short run at least.

In a first section, the imbalance tariff systems of four countries, namely Belgium, the Netherlands, France and Spain are described. Next, the methodology for comparing the impact of these tariff systems on wind power imbalance charges is explained. Results are presented in section 4, with specific attention to the Belgian case and the comparison of the different imbalance charge rules. Finally, a conclusion is provided in the last section.

[60] Assuming low operation and maintenance costs.

[61] Single imbalance pricing uses a single price for all positive and negative imbalances. Dual imbalance prices charge differently according to negative or positive imbalance of a balance responsible party.

5.3.2 Imbalance tariff designs of four countries

The imbalance tariff systems of four European countries are compared in terms of their impact on wind power imbalance settlement. Belgium, the Netherlands, France and Spain are chosen for their diversity in imbalance settlement tariffs. The tariff system of each country's TSO is described in this section. Although each TSO adopts its own terminology in different languages, for reasons of clarity, the same terms are used for the four countries. A reference is given to the original terms as well.

Some countries have special exemptions for wind power imbalances. Belgium for instance adopts an advantageous 10 % and 30 % fixed-price imbalance tariff for onshore and offshore wind power generation respectively. A negative imbalance higher than 30 % for an offshore wind farm is exempted of the regular imbalance tariff, as described in the next section, and will have to pay *1.08 · reference market price* (RMP) to the TSO instead; a positive imbalance will be bought up by the TSO at *0.92 · RMP*. This fixed-price imbalance tariff is predefined by law and leads to lower overall charges to be paid by the BRP [151; 152]. Other countries such as France and Germany adopt feed-in tariff systems for electricity from wind power and exempt wind turbines from paying imbalance tariffs.

To have the same level of comparison for all countries and since exemption regimes for imbalance settlement of wind power are subject to constant changes, the general imbalance rules are applied for every country. No exemption for imbalances from wind power is taken into account in the following analyses. Moreover, the wind power generators are assumed to act as BRPs themselves to settle imbalances with the TSO, thereby disregarding possible internal balancing of wind power with other generation units in a BRP's portfolio. This allows for an attribution of imbalance costs directly to wind power.

For conformity in the analyses made in the following and since balancing responsibility seems to be unavoidable for wind power producers in the future, electricity from wind power is considered to be sold on the spot market and the BRP has to pay for imbalances from wind power.

5.3.2.1 Belgium

The Belgian TSO, Elia, checks each 15 minutes whether the Balance Responsible Parties (BRPs) maintain their balance. If an imbalance is found, imbalance tariffs are applied to this BRP. In what follows, the imbalance tariff structure, which has been rethought in 2006 is discussed [114; 153]. The 2008 imbalance charges are based on the tariff structure further represented in Table 3.

Just like other TSOs, Elia disposes of various resources for keeping the system balanced, referred to as power reserves in section 2.2.2.1.. A supplier of downward regulating power will usually pay a compensation to the TSO. The energy itself will already have been sold to another party beforehand and by not having to actually produce this energy, fuel and other operation costs are saved by the supplier. A supplier of upward regulating power will usually get paid by Elia.

A negative BRP imbalance always leads to a payment from the BRP to Elia. Prices for positive BRP imbalance can either be positive or negative. A positive price for a positive imbalance implies a payment from Elia to the BRP and a negative price for a positive imbalance stands for a payment from the BRP to Elia[62] [154].

The imbalance settlement in Belgium is a mix of marginal and average cost pricing, capped with a certain percentage of the **reference market price (RMP)**. In a situation of negative BRP imbalance and negative system imbalance, the charge to the BRP is typically at least the marginal price for upward regulation. The charge can be even higher if 108% of the weighted average upward regulation price or of the RMP are found to be higher. The same reasoning can be made for the remuneration received by the BRP in case of a net downward regulation. For reasons of clarity, the Belgian system will be referred to as a marginal cost based imbalance charge system with a certain penalty coefficient in what follows.

The values in Table 3, expressing the calculation methods of the imbalance charges, are based on the described imbalance related parameters. It gives the calculation method for each combination of system imbalance and imbalance sign of the BRP.

[62] A negative payment states it would cost money to actually generate less electricity and reduce generation. This can occur in situations with low demand and many active inflexible generators, such as cogeneration, which cannot be switched off easily. Reducing the active generation would imply shutting down power plants that have to be started up again later. This comes at a cost. Negative payments rarely occur.

		System Imbalance	
		Positive: Net downward regulation	**Negative: Net upward regulation**
BRP imbalance	**Positive**	$\mathrm{Min}[\gamma \cdot WAP_D; \delta \cdot MP_D + (1-\delta) \cdot WAP_D]$ *(1)*	$0.92 \cdot RMP$
	Negative	$1.08 \cdot RMP$	$\mathrm{Max}[\alpha \cdot WAP_U; \beta \cdot MP_U + (1-\beta) \cdot WAP_U]$ *(2)*

Table 3: Elia imbalance tariff structure [153].

With: *(1)* 92% of the reference market price (RMP) is a maximum price
(2) 108% of the reference market price (RMP) is a minimum price
$\alpha = 1.08$ $\gamma = 0.92$ if $WAP_D > 0$ and 1.08 if $WAP_D < 0$
$\beta = \min(1; GUV/450)$ $\delta = \min(1; GDV/450)$

The total amount of system imbalance can also be referred to as the Net Regulation Volume (**NRV**). It is expressed in MWh for every quarter of an hour and can be positive or negative, depending on whether the upward or downward regulations of Elia prevail. The net system imbalance or NRV within a 15 minute timeframe is either positive or negative but both upward and downward regulation can be necessary within this timeframe. The Gross Upward Regulation Volume (**GUV**) and Gross Downward regulation Volume (**GDV**) sum up the upward and downward activations within every quarter of an hour respectively.

From January 1st 2007 on, the **reference market price (RMP)** is based on the Belpex day-ahead clearing price. In 2006, before the Belpex platform was operational, the Amsterdam Power Exchange (APX) price was applied [155; 156]. This RMP defines the equilibrium price of the regular power exchange and therefore has its origin outside of the imbalance settlement structure.

The calculation of the Belgian imbalance tariffs relies on both the weighted average price (WAP) and marginal price (MP) for regulation. The Weighted Average Upward regulation Price (**WAP_U**) and the Weighted Average Downward regulation Price (**WAP_D**) refer to the average price of all respectively upwards or downwards activations ordered by Elia for maintaining the balance in the Belgian control area. The marginal price for upward regulation (**MP_U**) stands for the highest price for upward activation that has been contracted by Elia[63]. The marginal price for downward regulation (**MP_D**) denotes the lowest of all ordered downward activations.

The α and γ indices have undergone various adjustments since the introduction of the new imbalance rules on January 1st 2006, as can be seen in Table 4. They define the spread between what a BRP has to pay for a negative imbalance and what it receives for a positive imbalance when the weighted average prices are used to define the imbalance settlement. The consequence of changing α and γ values is that the spread between the actual imbalance cost and the price to be paid, by either the BRP or Elia, is decreasing over the years. Also the spread on the RMP, which is now the difference between 108% and 92% of the RMP has decreased since 2006. Current indices reflect more the actual imbalance cost than they did in the beginning of 2006.

	α	γ
1st January 2006 - 30th September 2006	1.15	0.85
1st October 2006 - 31st December 2006	1.10	0.90
1st January 2007 - 30th September 2007	1.10	0.90
1st October 2007 - 31st December 2007	1.095	0.905
1st January 2008 - …	1.08	0.92

Table 4: Values for the α and γ indices for the calculation of imbalance tariffs over the years in Belgium [114].

5.3.2.2 Netherlands

TenneT, the Dutch TSO calculates an imbalance tariff for each successive 15 minute period as well. The charges a BRP has to pay or the sums it receives depend on the extent and the direction of the BRP imbalances on the one hand and the *regulation state* on the other hand. The imbalance tariff structure is represented in Table 5.

The different regulation states all refer to a particular regulation TenneT has to perform on the entire system. It is equivalent to the system imbalance, as presented in the Belgian imbalance system; the regulation state determines the direction of the system imbalance. When this regulation within a 15 minutes time frame is neither upward, nor downward, the regulation state is "**0**". When the regulation is

63 The upward and downward marginal prices are referred to by Elia as Highest activated Upward regulation Price (HUP) and the Lowest activated Downward regulation Price (LDP) respectively.

exclusively downward, that is when there is too much electricity generation in the system, the state is "**-1**". For an exclusively upward series, the state is "**+1**". A regulation state "**2**" is used for a situation where both upward and downward regulation are required within the 15 minutes time span. The regulation state "**2**" often occurs with shifts from upward to downward regulation or vice versa.

The various prices that the imbalance tariff structure is based on are determined by a merit order or "bid ladder", as depicted in Figure 29. This merit order is composed of all the upward and downward bids for regulating and reserve power with an activation time of up to 15 minutes. These bids are offered by regulating and reserve power suppliers. The merit order price per direction is set by the marginally deployed bid in that direction. The merit order gives an idea of what the final prices will be. Merit orders act as an indication to the market for the actual price and provide the suppliers of regulating and reserve power a base for their price setting. Not only the capacity of regulating and reserve power determines the final price, also the desired rate of deploying the energy plays an important role. More than one regulating bid can be activated at the same time to achieve a faster response to an imbalance. Moreover, a plant for regulating or reserve power having been activated for one period will have its repercussions on the subsequent periods. TenneT offers an overview of temporary merit orders on its website [157].

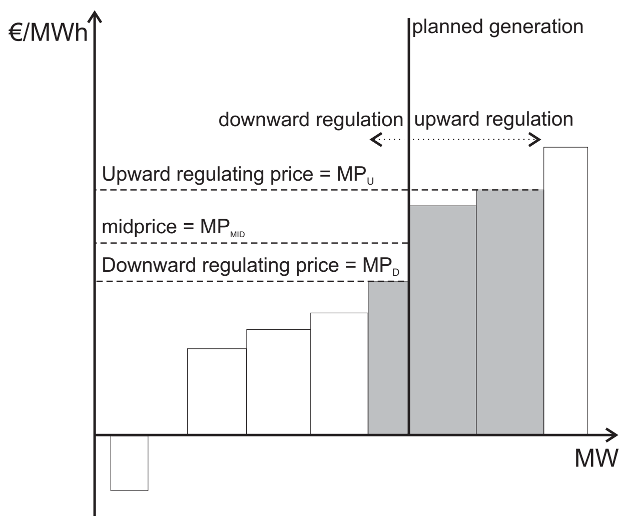

Figure 29: Example of a merit order or bid ladder. The merit order is composed of various bids and ordered according to increasing price [158]. The grey areas represent both upward regulation (to the right) and downward regulation (to the left). Since both upward and downward regulation are activated during one period, a regulation state "2" is in effect.

With a positive imbalance from the BRP, meaning a surplus of electricity generation on the BRP side, TenneT pays the calculated amount to the BRP. This amount can also be negative, in which case the BRP ends up paying TenneT. For a negative BRP imbalance, resulting from a shortage of the BRP, a charge is paid to TenneT. The amount of charge paid or remuneration received depends on the *regulation state* the system is in, as represented in Table 5. The table also reveals that the Dutch system is based on marginal cost pricing. The imbalance system is not linked to the RMP, nor to weighted average prices.

		Regulation state			
		Regulation state "-1"	Regulation state "0"	Regulation state "+1"	Regulation state "2"
BRP imbalance	Positive	MP_D-ic	MP_{mid}-ic	MP_U-ic	MP_D-ic
	Negative	MP_D+ic	MP_{mid}+ic	MP_U+ic	MP_U+ic

Table 5: TenneT imbalance tariff structure [157; 158].

Just as in the Belgian system, $\mathbf{MP_D}$ refers to the marginal downward regulating price. It is defined by the price for the last unit of activated downward regulating or reserve capacity on the merit order. In Figure 29 the grey area on the downward side of the regulation determines how much downward regulation has been activated and what the corresponding price is. The more downward regulation is necessary, the lower will the MP_D become. $\mathbf{MP_U}$ stands for the upward merit order price and is defined by the marginal cost of upscaling capacity through regulating and reserve capacity. The grey area of Figure 29 at the upward side of the imbalance defines the amount of upward regulation needed and the corresponding upward regulating price. When the system is in balance and the regulation state is "0", neither upward nor downward prices can be set. A "midprice" $\mathbf{MP_{mid}}$ is fixed as the midpoint between the lowest bid price at the upward regulating side and the highest bid price at the downward regulating side[64].

The incentive component **ic** forms part of the imbalance price as well. It is added to or subtracted from the marginal price to formulate the final imbalance tariff as can be seen in Table 5. To incite BRPs to maintain their balance and to avoid certain strategic behaviour, this component comes on top of the bid price to steer the market players in a certain direction. The ic has mainly been used at the launch of

[64] MP_D, MP_U and MP_{mid} are respectively referred to as P_{do}, P_{up} and P_{mid} in the TenneT imbalance rules.

the bidding system, when the market was in need of liquidity. However since the middle of 2003, the ic has remained at 0 €/MWh, implying that the market was functioning correctly without any need for additional incentives.

Additional information on the integration of wind power in the Dutch system can be found in [159].

5.3.2.3 France

The French TSO, referred to as "Gestionnaire du réseau de Transport d'Electricité" (RTE) has an imbalance tariff structure that is similar to the two previous ones [160; 161]. Imbalances from a BRP, be it positive or negative, give rise to financial compensation between RTE and the Balance Responsible Party. The imbalance charges are calculated for every half hour.

The French imbalance tariff system is based on marginal cost pricing, capped by the RMP. The imbalance price is calculated according to the value of the imbalance and the trend of the system imbalance, as represented in Table 6.

		System Imbalance		
		Positive	No imbalance	Negative
BRP imbalance	Positive	$WAP_D/(1+k)$ *(1)*	RMP	RMP
	Negative	RMP	RMP	$WAP_U \cdot (1+k)$ *(2)*

Table 6: RTE imbalance tariff structure [161].

With: *(1)*: this value may not exceed the reference market price
(2): this value may not fall below the reference market price

The reference market price (RMP), defined by the **Powernext Spot price** is an important element for the determination of the imbalance tariff [162]. It is fixed on the Powernext Day-Ahead market. Similar to the Belgian and Dutch system, the BRP can contribute to or counterbalance the system imbalance of RTE. Depending on which combination of total system imbalance and BRP imbalance, the BRP has to pay a charge or receives remuneration.

The imbalance prices, the system imbalance[65] and weighted average prices (WAP_U and WAP_D)[66] are public indicators of the balancing mechanism, to be freely consulted on the RTE website [160]. They have the same signification as defined in the Belgian case.

The Upward Average Weighted Price (**WAP_U**) is calculated according to formula (5.1) where the $Price_{iU}$ used varies depending on whether the offer has been activated to maintain balance of production and consumption, or for another reason. In the first case, the offer price from the balancing actor is applied. In the second case, the price applied is the lower of either the offer price or the highest price of the upward offers activated for maintaining balance. $Power_{iU}$ and $Duration_{iU}$ refer to the activated power by RTE and the duration of the activation[67] respectively.

$$WAP_U = \frac{\left(\sum_i Price_{iU} \times Power_{iU} \times Duration_{iU}\right)}{\sum_i Power_{iU} \times Duration_{iU}} \tag{5.1}$$

The WAP_D is calculated in a similar fashion:

$$WAP_D = \frac{\left(\sum_i Price_{iD} \times Power_{iD} \times Duration_{iD}\right)}{\sum_i Power_{iD} \times Duration_{iD}} \tag{5.2}$$

The "k" factor is now fixed at 0.05. It may be revised according to the procedure set out in the "Rules relative to Programming, the Balancing Mechanism and the Balance Responsible Entity System" [161]. Just as in Belgium, this index has changed over the years, implying a lower spread on imbalance settlement, as shown in Table 7.

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[65] This is referred to as *balancing trend* within the RTE [160].

[66] WAP_D and WAP_U are referred to as AWP_D and AWP_U respectively in the RTE imbalance rules.

[67] The duration of the activation is capped at 30 minutes, the time frame for which imbalance charges are calculated.

	k
... - 30th June 2004	0.2
1st July 2004 – 31st March 2005	0.18
1st April 2005 – 30th June 2006	0.15
1st July 2006 - ...	0.05

Table 7: Values for the k index for the calculation of imbalance tariffs over the years in France [160].

Apart from the already mentioned imbalance tariff, the BRP has to pay RTE on a monthly basis for its physical consumption of balancing energy. From 1st April 2005 on, the price charged is 0.09 €/MWh.

5.3.2.4 Spain

In Spain, the imbalance charges are calculated for every hour by "Red Eléctrica de España" (REE), the Spanish TSO. REE solves balancing issues through secondary and tertiary reserve or deviation management, depending on the magnitude or timescale considered[68] [164]. The BRPs are charged for their imbalances according to the rules set out in Table 8 and according to the perimeter the BRP is active in [164-166].

The imbalance regulation for wind power in Spain is already considered to account for up to 36% of the total imbalance regulation in the system, both for upward and downward regulation [167].

In addition to global system imbalance and BRP imbalance, the Spanish imbalance system makes a distinction based on "perimeters"[69] as well. Data on the prices applied can be found on a dedicated website of REE with information on the operation of the system [168].

The description of what can be understood by a perimeter is given in a resolution of the Spanish ministry of industry, tourism and commerce [166]. It can in a broad sense be described as a collection of units, which are usually grouped, referring to the large electricity generating companies in Spain. The perimeters have an influence on the imbalance tariff in the sense that the charges or remunerations for the BRP

[68] The secondary reserve, tertiary reserve and deviation management are referred to as "servicios de ajuste del sistema" [163].

[69] This is referred to as "zona de regulación" [166].

are dependent on the perimeter it is active in[70]. The BRP will receive an overall lower remuneration for its surplus when its perimeter is showing an overall surplus as well. The compensation for a surplus of the BRP gets more interesting when it is active in a perimeter with an overall deficit on the balance.

The calculation method for imbalances in the Spanish system is given in Table 8.

		System Imbalance	
		Positive	**Negative**
BRP imbalance	**Positive**	$RMP+\left[\frac{imbal_p\left(Pimbal_U\text{-}RMP\right)}{\sum_u imbalP_{u,p}}\right]$ *(1a)* or RMP *(1b)*	RMP
	Negative	RMP	$RMP+\left[\frac{imbal_p\left(Pimbal_D\text{-}RMP\right)}{\sum_u imbalN_{u,p}}\right]$ *(2a)* or RMP *(2b)*

Table 8: REE imbalance tariff structure [164; 165].

With:
- *(1a)* This formula represents the payment received by the unit *u* when the perimeter *p* it is active in shows a surplus on the balance
- *(1b)* In the case of the unit's perimeter *p* showing a deficit on the balance, the unit *u* will receive the reference market price (RMP)
- *(2a)* This formula represents the charge paid by the unit *u* when the perimeter *p* it is active in shows a deficit on the balance
- *(2b)* In the case of the unit's perimeter *p* showing a surplus on the balance, the unit *u* will pay the reference market price (RMP)

The RMP can be consulted in [168] as "Precios Marginales del Mercado Diario en España y Portugal" expressed in €/MWh. The values are given one day in advance. $\mathbf{imbal_p}$ relates to the imbalance in a certain perimeter; $\mathbf{imbalP_{u,p}}$ and $\mathbf{imbalN_{u,p}}$

[70] An exact analogy between the BRP on the one hand and the perimeter composed of different units or zones on the other hand, is not possible. For the comparison with other countries, a BRP in Spain has been chosen to represent the units or zones that are active within a certain perimeter. These BRPs have their imbalance charges and remunerations calculated according to the perimeter they are active in.

respectively denote the positive and negative imbalances of a unit u within a certain perimeter[71].

$Pimbal_U$ defines the surplus price of a perimeter and is chosen to be the lesser of both the RMP and the *average price of the energy used for downward regulation*. It is applied when the system has a net surplus. This downward regulation is performed by the TSO by means of deviation management[72] and tertiary and secondary regulation. **$Pimbal_D$** defines the deficit price of a perimeter and is chosen to be the highest of both the RMP and the *average price of the energy used for upward regulation*. It is applied when the system has a net deficit. This upward regulation is performed by the TSO by means of deviation management and tertiary and secondary regulation.

The prices of deviation management and tertiary and secondary regulation are calculated according to their magnitude and marginal cost. For the deviation management and tertiary regulation, in the case of emergency or other unforeseen event, REE can activate reserves that were originally not foreseen. This is referred to as "Mecanismo Excepcional de Resolución" [166]. To compensate for this measure, the surplus prices are then multiplied by a factor 1.15 and the deficit prices by 0.85. For the secondary regulation the same factors are applied when the tertiary reserve is fully depleted. The weighted average of these three elements determines the abovementioned average prices of the energy used for downward or upward regulation.

5.3.2.5 Overview of the imbalance tariff designs in the four considered countries

A summary of the four countries' imbalance tariff designs is given in Table 9, for a better understanding of the differences in imbalance cost outcomes.

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[71] $imbal_p$, $imbalP_{u,p}$ and $imbalN_{u,p}$ are respectively referred to as $DESV_p$, $DESVP_{u,p}$ and $DESVN_{u,p}$ in the REE imbalance rules.

[72] "Gestión de desvíos" in Spanish.

	Imbalance Pricing	Penalties	Specificity
Belgium	Marginal dual pricing	8%	capped at $(1 \pm 0.08) \cdot$ (RMP or WAP)
Netherlands	Marginal dual pricing	none (in practice)	4 regulation states
France	Average dual pricing	5%	capped at RMP
Spain	Average dual pricing	difference WAP and RMP, depending on perimeter	perimeters

Table 9: Overview of the most important characteristics of the imbalance tariff designs in Belgium, the Netherlands, France and Spain

The four considered countries apply a dual pricing system, referring to a different price for positive and negative BRP imbalance volumes. Incremental as well as decremental regulating power is needed for settling BRP imbalances. Single imbalance pricing, where one price is set for all imbalance volumes is not applied in these countries, giving additional incentives to BRPs to balance their own portfolio.

Two categories of dual pricing are distinguished, namely the marginal and average pricing. In the marginal pricing systems, the TSO passes on the cost of the last activated unit to the BRP, for the entire upward or downward system imbalance volumes. In an average pricing system, the actual cost for balancing upward or downward is passed on proportionally to the BRPs in imbalance. In general higher costs are paid by BRPs which have a negative imbalance under a marginal pricing than under an average pricing regime. Correspondingly, a BRP receives higher remunerations for positive imbalances under a marginal pricing regime.

5.3.3 Methodology

Two approaches are used for comparison of the four different imbalance tariffs. The Belgian electricity generation system is used as a reference in both cases; the four imbalance tariff rules are all applied to the same Belgian electricity generation system. Firstly, a given 24 hour wind speed forecast error vector is assumed to generate the only imbalance in the system. The ensuing imbalance costs for wind power are analysed. In a second approach, a Monte Carlo simulation[73] of various wind speed and residual system forecast errors from other electricity generators gives a more consistent view on the impact of the imbalance charges on the imbalance cost for wind power. Where the first approach only considers imbalances originating from wind power, a more realistic method is used in the second approach.

5.3.3.1 Reference system

The Belgian electricity generation system is chosen because of its variety of generation sources and availability of information. A reference system is used to isolate the imbalance tariff design from other aspects such as a different generation mix or different demand levels. The system is chosen as a reference for comparison of the different imbalance tariff structures.

The four typical wind speed and demand profiles, introduced in 4.2.5, have been chosen to analyse the impact of the imbalance charges on the cost of integration of wind power for the BRPs.

Approach 1

In a first step, the Belgian electricity generation system is used and the four countries' imbalance tariffs are calculated for this system. The Belgian system has about 16 GW of generation capacity and a peak demand of around 13 GW. The same average and marginal imbalance cost curves, as further determined in section 5.3.3.3 are applied for all tariff structures. Moreover, the imbalance coming from wind power is considered to be the only imbalance in the system. One vector of a standard normally distributed forecast error[74] with a standard deviation of 1 m/s is chosen, as represented in Figure 30. The forecast error depends to a large degree on the time ahead the forecast is made, which in turn depends on the gate closure time[75] of the electricity generation system. The longer ahead a forecast needs to be made, the less accurate it will be. A standard deviation of 1 m/s is found to be consistent with literature for a forecast made a relatively short time ahead [31; 169; 170].

[73] A Monte Carlo simulation is a computational algorithm that repeatedly computes results through random sampling of the input parameters. These parameters' statistical properties define the probabilities of being sampled.

[74] The concept of forecast errors was previously introduced in section 1.3.3.

[75] The concept of gate closure is explained in section 2.2.2.2.

The forecast error vector generates an imbalance for each of the 24 simulated hours. This vector constitutes the base for comparison and is found to be predominantly leading to negative imbalances of the BRPs[76]. The chosen imbalance vector slightly overestimates the wind speed when summing up all forecast errors over the 24 hours. For Spain, an additional assumption is made, namely that perimeter and wind power imbalance fall together. The distribution over positive and negative perimeter imbalance is evenly spread according to a random function.

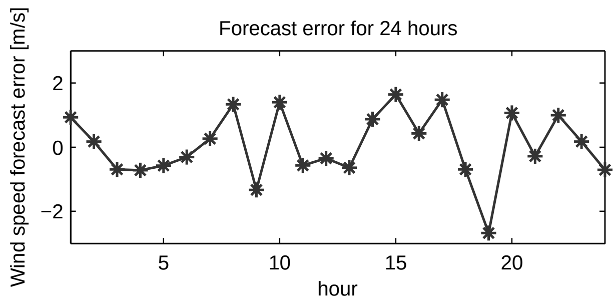

Figure 30: Wind speed forecast errors, generated from a 1 m/s standard deviation. Positive forecast errors indicate an overestimation of wind speed; negative forecast errors refer to an underestimation.

Approach 2

In a second phase, the same Belgian system is applied as a ground for comparison, still using the same AC and MC curves. This time however, a Monte Carlo approach is used to generate an average imbalance for wind power over numerous simulations. The Monte Carlo approach also considers an aggregate imbalance for the rest of the generation units. Wind power imbalance and residual imbalance are independent from one another and will interact. The imbalance from the other generation sources is taken to be uniformly distributed between the Belgian extreme imbalances measured in 2006 and 2007, namely 590 MW gross upward regulation volume and 400 MW gross downward regulation. The Monte Carlo algorithm is repeated for 1000 iterations to ensure convergence of the results. In the specific case of the application of the Spanish imbalance rules, the wind power generator is assumed to be active in a certain perimeter. The imbalance of the perimeter is chosen to be between 295 MW negative and 200 MW positive imbalance, or half of the system limit values.

[76] A positive forecast error, leading to an overestimation of wind power, causes a BRP to have a deficit. A positive forecast error leads to a negative imbalance for the BRP.

There are advantages and disadvantages to the method described in phase 1 and 2. The main advantage of this approach is that it implicitly takes into account the opportunity cost of the reserves. Elia calculates the WAP and MP based on a market principle since they have to buy this reserve on the market first. In reality the actual reserves cost is a combination of buying reserves beforehand and of taking short term initiatives for balancing. The downside of this view is that it is not completely modelled but based on externally fitted WAP and MP curves, as explained further on. The disadvantage of looking at different rules applied to the Belgian system is that each system might well have a different "best rule" that is dependent on the system itself.

5.3.3.2 Forecast error, imbalance charges and loss of revenue

The forecast errors are such that the actual wind speed is assumed to always be the same; only the wind speed forecast depends on the random feature of the standard normally distributed forecast error. This allows for a comparison of costs where there is no difference in actual wind power output. The system imbalance for each hour and the Spanish perimeter imbalance are the other random factors in the analysis that come into play when applying approach 2. On the whole, positive and negative imbalances of wind speed and the entire system occur to the same extent in the second approach.

The costs or remunerations for the BRP are calculated for each hour. This is an approximation for the usually more detailed balance settlement that might be calculated every 15 minutes such as in Belgium or the Netherlands or every half hour such as in France.

The revenue from wind power is determined through the value of the electricity from wind power sold on the spot market. The revenues from feed-in premiums or green certificates are not taken into account. The analyses are made without any explicit support scheme for wind power, to have a same ground for comparison. Support schemes influence the significance of imbalance pricing designs. The imbalance costs are weighted off against the revenues form electricity sold.

5.3.3.3 Determination of RMP, WAP and MP

Weighted average price (WAP) and marginal price (MP) values are based on historical 15-minute data of the Belgian TSO Elia for the years 2006 and 2007

[114].[77] For having the same ground of comparison, the same RMP, WAP and MP values are used for the four countries. Applying the same RMP, WAP and MP values to the imbalance tariff design of the four countries implies that the imbalance tariff designs are independent of these values. In reality, these values will differ for every country, since they depend on the generation mix and the contracted reserves of each TSO. Figure 31 demonstrates the relationship between demand and spot market price on the left side. A 2nd degree polynomial is established from this relationship. On the right, the link between the demand and MP is shown. A distinction is made between three levels of system imbalance, namely system imbalance>0 MW, 0 MW ≥ system imbalance > -150 MW and system imbalance ≤ -150 MW[78]. For each of these system imbalance levels, a function is determined of MP in relation to demand. Based on these functions, a value for RMP, WAP and MP can be set for each of the hours in the given demand profiles.

RMP in function of demand (expressed in kW) (with a R^2 of 0.165):

$$RMP = 3.2 \cdot 10^{-12} \cdot demand^2 - 0.0001 \cdot demand + 213.2559 \tag{5.3}$$

MP_U for 0 MW ≥ system imbalance > -150 MW[79] in function of demand (expressed in kW) (with a R^2 of 0.115):

$$MP_U = 5.21 \cdot 10^{-13} \cdot demand^2 - 7.7 \cdot 10^{-6} \cdot demand + 59.30 \tag{5.4}$$

MP_U for system imbalance ≤ -150 MW in function of demand (expressed in kW) (with a R^2 of 0.000075):

$$MP_U = 1.57 \cdot 10^{-7} \cdot demand + 165.18 \tag{5.5}$$

MP_D for system imbalance > 0 MW in function of demand (expressed in kW) (with a R^2 of 0.219):

$$MP_D = -5.02 \cdot 10^{-13} \cdot demand^2 + 6.69 \cdot 10^{-6} \cdot demand - 26.10 \tag{5.6}$$

[77] Since the system imbalance data of Elia is based on MWh/h equivalents of 15-minute imbalances, the functions calculated below can be applied to calculate costs for hourly imbalances as well.

[78] In Belgium, 150 MWh/h is the amount of maximum available secondary reserve. The average level of secondary reserve is 137 MW [171].

[79] The 150 MW is actually the equivalent in MWh for an imbalance of 150 MW during 15 minutes.

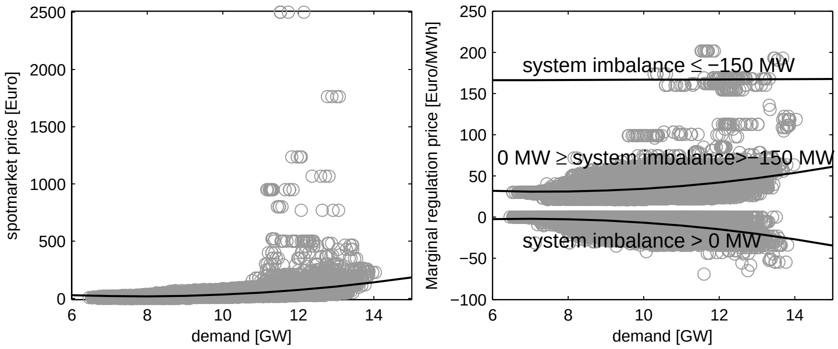

Figure 31: Relationship between demand and spot market price (RMP) on the left figure; relationship between demand and marginal imbalance price (MP) on the right figure for three different levels of system imbalance. Using Belgian historical data from 2006 and 2007 [114].

The WAP is calculated, based on the MP. For imbalances under 150 MWh, the WAP has the same value as the MP. For a given demand, the imbalance charge is considered to be constant. For imbalances over 150 MWh, it is calculated as the weighted average of the MP for the imbalance up to 150 MWh, and the MP for the amount of imbalance over 150 MWh.

The same RMP, WAP and MP functions are used to compare the imbalance rules of the four considered countries. For Spain, the *average price of the energy used for downward or upward regulation*, taken from the prices of deviation management and tertiary and secondary regulation, is assumed to be equal to the WAP_D and WAP_U respectively. No information can be obtained on the constituent elements that make up the normal calculation of the average price. However, since the WAP is implicitly calculated through the average of the different marginal prices, it can be assumed the WAP is a very good approximation of this average price for imbalance.

Negative MP or WAP values are hardly ever obtained. Only when a large number of power plants needs to be switched off for purposes of oversupply, for example when many cogeneration power plants are operational, a negative MP_D or WAP_D can be obtained. In the data used to calculate the WAP_D and WAP_U based on demand and system imbalance, no occurrence of negative values were noted. Therefore, no negative values will occur in the performed analyses.

Approaching the RMP, WAP and MP values through the relationship with the overall demand is not necessarily the only method. Although it is the main driver for the cost evolutions, other parameters that are not taken into account do also exercise an influence. The amount of imbalance for instance is also important, since the more regulation volume is needed, the more expensive will the reserves become. The different price patterns of WAP and MP during week and weekend days, mentioned in [172], can be explained by the difference in demand level during a weekday or weekend day. The demand will determine the price ladder to be used but the system imbalance will tell which position to take on this price ladder

5.3.4 Results

The results for the two considered approaches are reported in this section. Firstly, using approach 1, the imbalance cost of one determined wind speed forecast error for every hour is described with wind power constituting the only source of imbalance in the system. In the second approach, the interaction of residual system imbalance and wind speed forecast errors is looked at. The amount of installed wind power, wind speed and demand profiles are varied and applied to the countries' imbalance tariff structures to investigate their impact on final imbalance charges.

As previously stated, operating wind power in an electricity generation system usually comes at very low cost. Fuel costs for electricity from wind power are zero and the net revenues can be considerable.

5.3.4.1 Cost difference for approach 1

The costs from having an imbalance in wind power output are examined in this section. Firstly, the impact of several parameters on the imbalance charges in the Belgian system is studied. Next, the different imbalance tariff rules are compared, taking the Belgian electricity generation system as reference system.

Imbalance charges applying Belgian imbalance tariff rules

In a first analysis, the impact of forecast errors on wind power output in Belgium is examined. Unforeseen forecast errors lead to imbalances in the system, which have to be covered by reserves from the TSO and for which an imbalance charge is due or a payment will be received by the BRP.

The inclusion of imbalance settlement of wind power can have a significant impact on the operations of a BRP. Incomes generated through the sale of electricity originating from wind power can seriously be offset due to aggregate imbalance charges. An illustration is given in Table 10, where the reduction in cost savings due to imbalance charges is represented relative to the value of the electricity from wind power sold on the spot market at the spot market price (RMP)[80]. A standard deviation of 1 m/s is used as forecast error and the demand profile of *Day 1* is applied. Other demand profiles are found to render comparable results. Up to 2000 MW of installed wind power is considered, corresponding to about 12% of peak power demand in Belgium [114].[81]

		Wind speed profiles			
		Windday A	Windday B	Windday C	Windday D
Installed wind power [MW]	500	-48.09%	-8.10%	-0.23%	-10.21%
	1000	-58.70%	-11.54%	-0.27%	-14.38%
	1500	-73.17%	-13.48%	-0.32%	-18.38%
	2000	-75.68%	-15.26%	-0.38%	-20.63%

Table 10: Income loss from BRP due to imbalance charges from wind power, according to the Belgian imbalance tariff, paid for forecast errors in the Belgian electricity generation system; for a standard deviation of 1 m/s using demand profile of Day 1.

The relative income loss due to imbalance of wind energy strongly depends on the chosen situation. Both original value of the sold wind energy and the imbalance charges affect the outcome. The overall imbalance charges represent the net cost of imbalances after aggregating both payments received by the BRP for positive imbalances and charges paid for negative imbalances. This aggregate value has only a limited impact when applied to *Windday C* whereas the impact on *Windday A* is vast. For the former they practically do not generate any net imbalance cost. The latter undergoes net charges that almost completely neutralize income from selling wind power, with up to 70% of the value of wind energy being lost to imbalance charges.

It is obvious that the applied wind speed profile plays an important role in the determination of imbalance charges. Two reasons can be found for this. Firstly, the absolute level of wind power is dependent on the wind speed. The same absolute deviation on low wind speeds will have relatively more impact on the revenues than on high wind speeds. Secondly, the location of the wind speed on the power curve is

[80] As explained in section 5.3.3.3, the RMP depends on the demand.
[81] The demand and wind speed profiles are introduced in section 4.2.5 and can be consulted on the last page of the thesis for easy reference.

of importance as well. A certain forecast error, expressed in m/s, has a larger impact on the steep parts of the cubic power curve than on the flatter parts as exemplified in Figure 32. That is why *Windday C* experiences almost no effect of the forecast error. The small deviations in wind speed hardly influence the power output since during most of the 24 hours, the wind speed is close to or over the wind speed for rated power. For the other wind speed profiles the opposite is true. The same forecast error on wind speed might have a considerable impact on the output from the wind turbine.[82]

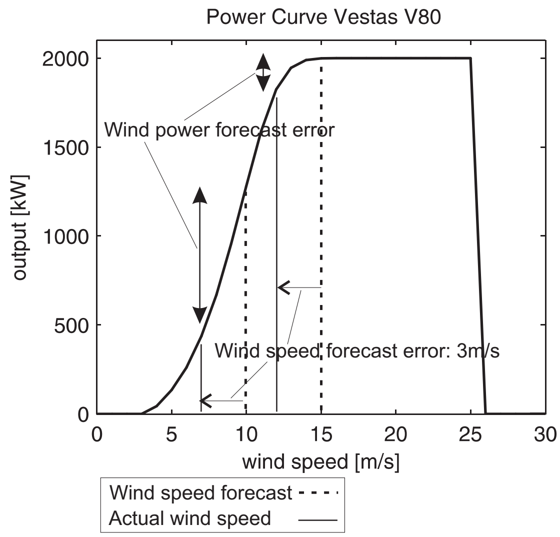

Figure 32: Impact of the same positive 3 m/s wind speed forecast error at forecasts of 15 and 10 m/s on the wind power forecast error.

The capacity of installed wind power influences the relative loss of revenue as well. On the one hand, the RMP is assumed to decrease with higher penetration factors of wind. With increasing wind power output, more expensive power plants are outperformed in the electricity generation system and market prices will decrease accordingly. Consequently, large amounts of electricity generated by wind power do influence the spot market. This effect is also referred to as market resilience, or the price sensitivity due to an increase in offer or demand on the market [173]. On the other hand, more installed capacity without significant geographical dispersion, which is virtually impossible to achieve in a small country, leads to larger absolute imbalances. In the Belgian imbalance charge calculation, from a 150 MW of shortage

[82] A static power curve is used. With a dynamic power curve, additional fluctuations in wind power would arise.

level on, the imbalance charges become significantly more expensive. Larger absolute imbalances in wind energy lead to this level being reached more frequently which in turn bring about higher costs.

The net imbalance charges become larger with increasing forecast errors. With a high 3 m/s standard deviation on the wind speed, as presented in Table 11, the imbalance cost of wind power with *Windday A* becomes three times higher than the actual revenues from selling the wind energy on the market. For the wind speed profiles of *Windday B* and *Windday D*, net imbalance charges amounting to up to 40 % and 50 % of the sales revenue are noted.

		Wind speed profiles			
		Windday A	Windday B	Windday C	Windday D
Installed wind power [MW]	500	-319.03%	-19.97%	0.91%	-28.00%
	1000	-329.75%	-28.18%	1.07%	-37.52%
	1500	-328.28%	-33.71%	1.27%	-42.92%
	2000	-332.23%	-39.25%	1.53%	-48.83%

Table 11: Income loss from BRP due to imbalance charges from wind power, according to the Belgian imbalance tariff, paid for forecast errors in the Belgian electricity generation system; for a standard deviation of 3 m/s using demand profile of Day 1.

The demand profile influences the wind power income loss due to imbalances in two counteracting ways. On the one hand a lower demand usually implies a lower market price and corresponding lower income from the sale of wind power. On the other hand a lower demand leaves cheaper power plants available for balancing services in the system, thereby lowering the imbalance charges. Both effects are demonstrated in Figure 31. The relative income loss with the demand profile of *Day 4* is given in Table 12.

		Wind speed profiles			
		Windday A	Windday B	Windday C	Windday D
Installed wind power [MW]	500	-66.50%	-12.35%	-0.54%	-15.66%
	1000	-176.67%	-45.21%	-0.55%	-56.79%
	1500	-329.54%	-50.33%	-0.52%	-87.69%
	2000	-357.78%	-47.31%	-0.46%	-86.22%

Table 12: Income loss from BRP due to imbalance charges from wind power, according to the Belgian imbalance tariff, paid for forecast errors in the Belgian electricity generation system; for a standard deviation of 1 m/s using demand profile of Day 4.

The conclusion is that imbalance charges can become very important in the Belgian system when wind profiles with low aggregate wind speeds are used. They can nullify the potential gains selling cheap wind power in the market and even lead to higher costs than in a situation without wind when the forecast error becomes significant. It is therefore important to place wind turbines in locations with sufficiently high and abundant wind speeds. It is equally important to accurately forecast these wind speeds. Furthermore, balancing one wind farm on its own will cause higher overall costs for wind power since in general imbalances of all elements in a system tend to even each other out to some extent. This can be seen in approach 2, where the wind power imbalance interacts with an independent system imbalance.

When the exemption of regular imbalance rules for renewable energy in the Belgian system is used, the previously mentioned 10 % allowed imbalance on onshore wind power output under a special imbalance charge regime can be applied. This gives a somewhat lower impact on costs for wind power imbalance as can be seen in Table 13. Since installed wind power of up to 2000 MW onshore is a lot to conceive for Belgium, the same exercise is performed for an offshore wind farm, benefiting from a 30 % allowed imbalance, as illustrated in Table 14.

		Wind speed profiles			
		Windday A	Windday B	Windday C	Windday D
Installed wind power [MW]	500	-41.18%	-5.19%	0.35%	-8.22%
	1000	-51.65%	-8.28%	0.41%	-12.16%
	1500	-65.98%	-9.80%	0.49%	-15.88%
	2000	-68.35%	-11.10%	0.60%	-17.82%

Table 13: Income loss from BRP due to imbalance charges from wind power, according to the Belgian imbalance tariff, paid for forecast errors in the Belgian electricity generation system; for a standard deviation of 1 m/s using demand profile of Day 1. This time using the exemption of 10% imbalance at a fixed tariff for renewable energy.

		Wind speed profiles			
		Windday A	Windday B	Windday C	Windday D
Installed wind power [MW]	500	-35.64%	-4.61%	0.56%	-6.70%
	1000	-36.35%	-5.17%	0.66%	-7.49%
	1500	-38.95%	-5.83%	0.79%	-8.41%
	2000	-40.98%	-6.59%	0.95%	-9.48%

Table 14: Income loss from BRP due to imbalance charges from wind power, according to the Belgian imbalance tariff, paid for forecast errors in the Belgian electricity generation system; for a standard deviation of 1 m/s using demand profile of Day 1. This time using the exemption of 30% imbalance at a fixed tariff for renewable energy.

Imbalance charges applying country-specific imbalance tariff rules

The imbalance charges vary widely according to the applied imbalance rules. Each set of rules, corresponding to a specific country has its own influence on the aggregate costs for imbalances caused by wind speed forecast errors. Figure 33 shows the differences in relative costs due to imbalance of forecasted and actual wind energy for the four countries considered. As already explained above, the relative loss in income from wind power is significantly higher for the wind speed profile of *Windday A*.

For both illustrated wind speed profiles, the Belgian imbalance rules lead to the largest net loss in revenues from wind power. The Netherlands have the most beneficial tariff system for very low wind output and high demand levels, combining the low wind speed profile of *Windday A* with 500 or 1000 MW installed wind power.

On higher levels of wind power and lower demand levels for the same wind speed profile, the Spanish tariff system becomes the most interesting option.

Not shown in Figure 33 but further clarified in Table 15, over the four considered wind speed profiles, with the exception of *Windday C*, the impact of the imbalance on the net income decreases with increasing wind speed profiles for reasons explained above. Over the four considered wind speed profiles, the Spanish imbalance rules give the cheapest solution to the BRP in terms of net imbalance charges. Only for very low amounts of electricity from wind power will Spain show less advantageous outcomes than the Netherlands. For the high wind speed profile of *Windday C*, the differences between the four countries are relatively small. The overall imbalance costs remain low for that wind speed profile.

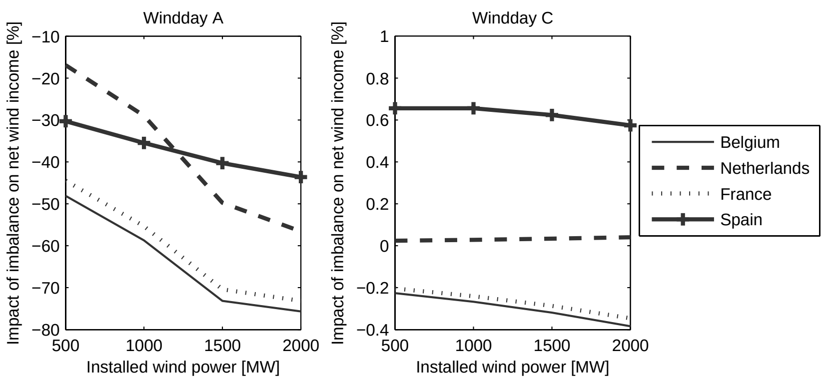

Figure 33: Impact of net wind power imbalance charges relative to the revenues obtained from selling electricity generated from wind power on the market according to the four imbalance tariffs. For increasing levels of installed wind power, the demand profile of Day 1 and two wind speed profiles, namely Windday A and D.

The first reason for Spain rendering the lowest imbalance charges is to be found in the imbalance tariff structure. Where Elia and TenneT heavily penalise imbalances by charging the marginal cost[83] of the procured reserves, RTE and REE only charge the average cost of the acquired reserves. The marginal cost-based imbalance tariff plays to the disadvantage of the BRP having a negative imbalance, for which the TSO has to provide upward regulating service. This is slightly compensated by the likewise higher payments from the TSO to the BRP for a positive imbalance. However, the

[83] As explained above, Belgium actually has a mix of marginal and average cost pricing. In reality it most often boils down to marginal cost pricing with a certain cost margin.

remunerations for positive imbalances seldom compensate for the charges of negative imbalances. On the whole, a marginal cost-based tariff system brings about higher imbalance costs for the BRP than an average cost-based system. Moreover, for France and Belgium, the pricing of imbalances is capped by the spot market price, thereby automatically leading to the least interesting upward and downward regulation charges for the BRP.

The second element that determines the outcome of the imbalance charges is the chosen margin over the average or marginal cost. Both Belgium and France adopt a certain margin to be included in the price setting of the imbalance charges. The Netherlands and Spain do not apply such margin. Both the charges being additionally constrained through the spot market price and the use of margins on top of regulation costs, lead Belgium and France to have the most expensive net imbalance charges. Belgium remains the least interesting option for a BRP due to the marginal cost pricing, as opposed to the French average cost pricing.

Table 15 gives an overview of the absolute imbalance charges. The differences between the four countries are very clear for the four considered wind speed profiles. This remains consistent for other levels of demand or wind power capacity and for higher forecast error values, as demonstrated in Tables 15 to 18. A remarkable fact is the aggregate gains that are obtained with the high wind profile of *Windday C* by the Netherlands and Spain. The net gains prove that the overestimation of wind power, with ensuing imbalance charges to be paid by the BRP, is compensated by the payments from the TSO to the BRP for underestimation of wind power. The relatively lower charges can be explained by the shape of the power curve, as mentioned above. The relatively higher payments to the BRP can be explained by the particular timing of the underestimations during the day. These are predominantly situated during the morning, at wind speed levels that can still impact the electricity generation for changes in wind speed. In the afternoon, when overestimations predominate, higher wind speed levels are observed that undergo less influence of forecast errors. When a prediction of for instance 22 m/s results in 20 m/s actual wind speed, no effect is observed on the energy output since both 20 m/s and 22 m/s allow the turbine to reach its rated capacity.

When taking the reasoning of high wind speeds further, the opposite will become true. For very high wind speeds an underestimation can be the difference between forecasting full rated wind power output and crossing the cut-out speed of wind power, thereby losing all of its energy production.

		Wind speed profiles			
		Windday A	Windday B	Windday C	Windday D
Country	BELGIUM	-114.55	-130.01	-4.82	-135.34
	NETHERLANDS	-56.56	-93.47	0.51	-85.55
	FRANCE	-108.03	-124.58	-4.35	-129.00
	SPAIN	-69.25	-59.87	11.83	-69.15

Table 15: Net imbalance charges in k€ for 1000 MW of installed wind power for the demand profile of Day 1 with a 1 m/s forecast error applying the different imbalance charges of each country. A negative value stands for cost to be paid by the BRP to the TSO; a positive value refers to the TSO paying the BRP.

		Wind speed profiles			
		Windday A	Windday B	Windday C	Windday D
Country	BELGIUM	-283.91	-269.97	-9.65	-306.92
	NETHERLANDS	-212.25	-211.57	1.03	-254.87
	FRANCE	-274.38	-260.18	-8.69	-297.49
	SPAIN	-163.68	-163.32	14.43	-183.15

Table 16: Net imbalance charges in k€ for 2000 MW of installed wind power for the demand profile of Day 1 with a 1 m/s forecast error applying the different imbalance charges of each country. A negative value stands for cost to be paid by the BRP to the TSO; a positive value refers to the TSO paying the BRP.

		Wind speed profiles			
		Windday A	Windday B	Windday C	Windday D
Country	BELGIUM	-79.56	-113.66	-3.23	-111.42
	NETHERLANDS	-52.63	-99.25	-0.85	-89.82
	FRANCE	-76.12	-109.85	-2.96	-107.29
	SPAIN	-26.90	-25.06	6.55	-25.49

Table 17: Net imbalance charges in k€ for 1000 MW of installed wind power for the demand profile of Day 2 with a 1 m/s forecast error applying the different imbalance charges of each country. A negative value stands for cost to be paid by the BRP to the TSO; a positive value refers to the TSO paying the BRP.

		Wind speed profiles			
		Windday A	Windday B	Windday C	Windday D
Country	BELGIUM	-77.13	-113.20	-2.35	-106.85
	NETHERLANDS	-53.29	-102.59	-1.83	-92.28
	FRANCE	-74.08	-109.79	-2.28	-103.37
	SPAIN	-30.04	-26.05	4.16	-31.554

Table 18: Net imbalance charges in k€ for 1000 MW of installed wind power for the demand profile of Day 3 with a 1 m/s forecast error applying the different imbalance charges of each country. A negative value stands for cost to be paid by the BRP to the TSO; a positive value refers to the TSO paying the BRP.

		Wind speed profiles			
		Windday A	Windday B	Windday C	Windday D
Country	BELGIUM	-72.25	-112.09	-2.44	-106.14
	NETHERLANDS	-51.76	-105.28	-2.20	-94.70
	FRANCE	-70.34	-109.14	-2.40	-103.36
	SPAIN	-12.51	-11.35	3.38	-13.42

Table 19: Net imbalance charges in k€ for 1000 MW of installed wind power for the demand profile of Day 4 with a 1 m/s forecast error applying the different imbalance charges of each country. A negative value stands for cost to be paid by the BRP to the TSO; a positive value refers to the TSO paying the BRP.

5.3.4.2 Cost difference approach 2

Another, more important factor in the cost evolution of imbalances from wind power is to be found in the interaction with the residual imbalance in the system, which was not taken into account in *approach 1*. Since both wind power imbalance and system imbalance are normally uncorrelated, in general, the imbalance originated from wind speed forecast errors can be counterbalanced by the imbalance of other components in the system. Compared to the previous section, wind power is not considered to be the only source of imbalance anymore and the imbalance costs for wind power are significantly reduced. The low correlation between imbalances is reinforced for larger geographical spreading of wind power and for a larger number of elements in the systems. More uncorrelated constituents that lead to imbalances bring about lower overall imbalances, relative to the system size. This shows the importance of interconnecting comparatively isolated systems to one another.

As explained above, the second approach still uses the Belgian RMP and marginal and average regulation prices. At this point however, the system is assumed to have its own imbalance, which interacts with the imbalance from wind power forecast errors. The imbalances caused by wind power are added to the system imbalance. A Monte Carlo approach is adopted to simulate different possible outcomes of system imbalance and forecast errors. The system imbalance interacts with the imbalance of wind power. Both imbalances are not perfectly correlated and therefore even each other out to some extent, thereby lowering the overall imbalance costs for wind power. When using the Monte Carlo approach for determining imbalance charges, the results are no longer dependent on the one random 24 hour forecast error vector. Positive and negative forecast errors of wind speed happen just as often. As Table 20 illustrates, this factor also leads to lower costs than in the previous section since at this point, using Monte Carlo simulation, positive and negative imbalances occur in the same proportions, whereas in approach 1, a negative imbalance slightly dominated.

		Wind speed profiles			
		Windday A	**Windday B**	**Windday C**	**Windday D**
Country	**BELGIUM**	-77.35	-112.65	-11.13	-86.41
	NETHERLANDS	-34.71	-47.60	6.04	-33.25
	FRANCE	-71.50	-102.54	-9.21	-77.44
	SPAIN	-37.63	-23.07	9.21	-12.58

Table 20: Imbalance charges in k€ for 1000 MW of installed wind power for demand profile Day 1 with a 1 m/s forecast error applying the different imbalance charges of each country, using the Monte Carlo approach of simulation. A negative value stands for cost to be paid by the BRP to the TSO; a positive value refers to the TSO paying the BRP

		Wind speed profiles			
		Windday A	Windday B	Windday C	Windday D
Country	BELGIUM	-74.36	-119.31	-14.33	-93.21
	NETHERLANDS	-34.72	-51.15	5.15	-39.13
	FRANCE	-70.59	-112.56	-12.96	-87.50
	SPAIN	-30.90	-35.03	2.64	-24.00

Table 21: Imbalance charges in k€ for 1000 MW of installed wind power for demand profile Day 2 with a 1 m/s forecast error applying the different imbalance charges of each country, using the Monte Carlo approach of simulation. A negative value stands for cost to be paid by the BRP to the TSO; a positive value refers to the TSO paying the BRP

		Wind speed profiles			
		Windday A	Windday B	Windday C	Windday D
Country	BELGIUM	-73.13	-122.09	-17.17	-92.89
	NETHERLANDS	-33.29	-53.33	3.52	-38.09
	FRANCE	-69.73	-116.22	-16.24	-87.83
	SPAIN	-29.01	-35.21	-2.10	-24.23

Table 22: Imbalance charges in k€ for 1000 MW of installed wind power for demand profile Day 3 with a 1 m/s forecast error applying the different imbalance charges of each country, using the Monte Carlo approach of simulation. A negative value stands for cost to be paid by the BRP to the TSO; a positive value refers to the TSO paying the BRP

		Wind speed profiles			
		Windday A	Windday B	Windday C	Windday D
Country	BELGIUM	-73.06	-126.23	-17.03	-99.06
	NETHERLANDS	-32.67	-53.59	4.73	-40.32
	FRANCE	-70.42	-121.55	-16.18	-95.26
	SPAIN	-26.21	-38.81	-2.05	-29.79

Table 23: Imbalance charges in k€ for 1000 MW of installed wind power for demand profile Day 4 with a 1 m/s forecast error applying the different imbalance charges of each country, using the Monte Carlo approach of simulation. A negative value stands for cost to be paid by the BRP to the TSO; a positive value refers to the TSO paying the BRP

In this setting, Spain can be considered having the cheapest imbalance tariff system for wind power. The reason has to be found in the fact that it adopts, together with France, a tariff rule based on average cost pricing, rather than marginal cost pricing. Since the cost paid by the BRP to the TSO predominates compared to the payments from TSO to BRP, the overall lower average costs lead to more interesting conditions for the wind producer. Disregarding other parameters, this creates a more interesting environment for wind power investments. This is however no appraisal of the system that needs to be used. The best system for a given country depends on the desired policy objectives in terms of power imbalances.

The second factor influencing the outcome of wind imbalance charges is the margin set forward by the TSO. The Dutch margins on imbalance costs have been set to *0* in the last few years, causing the BRP only to pay for the marginal cost, without any surplus. The French and Belgian system still adopt a certain increment over the costs, although it has to be stated that these margins have consistently decreased over the past years. The combination of more expensive marginal pricing and margins on top of the costs, make the general Belgian imbalance system the least interesting option for BRPs that have to pay for wind power imbalances.

The impact of the overall demand level is not very high. Since with decreasing demand, both upward and downward regulation costs decrease, the net charges will only slightly be influenced by this change. As demonstrated in Table 20 till Table 23 no clear impact of demand profiles on net imbalance charges can be observed.

5.3.4.3 Distribution of imbalance charges

BRPs may have incentives to provide biased forecasts in their strategy, as studied by [140; 141; 143]. If the difference between the charge paid for a negative BRP imbalance and the remuneration received for a positive BRP imbalance are modest, such as in single pricing systems, this bias can be expected to be small. This is especially true when the imbalance tariffs are approximately following the market prices.

The spread of imbalance prices for positive and negative BRP imbalances are analyzed for the cost calculations carried out in the previous section. For each of the calculated values in Table 20 to Table 23, the average tariff of the different imbalance situations and the relative occurrence of the different situations are determined. The four (or six) possible situations are defined by the combination of system imbalance with BRP imbalance. For the Belgian and Spanish tariff design, a positive or negative system imbalance can be combined with a positive or negative

BRP imbalance. In France and the Netherlands, the additional situation of having no imbalance is also taken into account. Examples of average costs and occurrence of each of the defined situations are given for the wind speed profile of *Windday D* , the demand profile of *Day* 1 and 1000 MW of installed wind power for Belgium and the Netherlands, in Table 24 and Table 25, respectively. Additional results for other wind speed profiles, installed wind power levels and country designs are included in Appendix C.

		System Imbalance	
		Positive	Negative
BRP imbalance	Positive	21 € (25%)	95 € (27%)
	Negative	114 € (15%)	156 € (33%)

Table 24: Average values and occurrence (between brackets) of imbalance costs and remunerations for the four imbalance situations, in Belgium, for the case of Windday D, Day 1 and 1000 MW of installed wind power.

		System Imbalance		
		Positive	Zero	Negative
BRP imbalance	Positive	21 € (24%)	-	134 € (28%)
	Negative	21 € (16%)	-	139 € (32%)

Table 25:Average values and occurrence (between brackets) of imbalance costs and remunerations for the four imbalance situations, in the Netherlands, for the case of Windday D, Day 1 and 1000 MW of installed wind power. Note that situations of zero imbalance do not occur in this case.

When comparing the difference in **average tariff** between positive and negative BRP imbalances for the different countries, two categories can be distinguished. On the one hand, the Belgian and French tariff designs are so that a considerable difference exists between what a BRP receives for a positive imbalance and what it pays for a negative imbalance. This is due to the application of penalties and price caps in these imbalance tariff rules. The Dutch and Spanish tariff designs, on the other hand, are more oriented towards a single price system. In Table 25, the difference between the remuneration for a positive BRP imbalance and the cost for a negative BRP imbalance are negligible for positive system imbalance, due to the incentive component being equal to zero and no other influence subsisting. The difference is modest for a negative system imbalance: the incentive component is still zero but the high occurrence of negative BRP imbalance is correlated to the negative system imbalance, thus slightly raising the imbalance costs. Table 24 and Table 25 also illustrate the spread between positive and negative system imbalance. Costs are higher when the system has a negative imbalance than when it has a positive imbalance.

The amount of installed wind power, wind speed and demand profiles, all influence the average tariffs to some extent. Most notable, is the impact of demand on the tariff due to its direct link with MP, WAP and RMP calculation. Higher demands automatically lead to higher tariffs.

The difference between a one- and two-price system is also discussed in [78], where discrepancies in the tariff system incite BRPs to avoid short positions. This has for consequence that BRPs are inclined to set themselves in situations where they expect to have a positive imbalance, thus avoiding more expensive charges paid for negative BRP imbalances. They under-nominate their expected injections for maximisation of their profits.

The difference in **occurrence** of the four imbalance situations is the same for the four considered countries, since the same cases are examined. With the spread of system imbalance taken to be between 590 MWh negative and 400 MWh positive imbalance, logically, negative system imbalances occur most frequently in the performed simulations, about 60% of the time.

Situations where system imbalance and BRP imbalance have the same sign, dominate the ones where the signs are different. The BRP imbalance influences total system imbalance. If a BRP imbalance is negative, it will contribute to the negative side of the system imbalance; if it is positive, it positively contributes to system imbalance. Comparing the average occurrence values for increasing amounts of wind power (as represented in Appendix C), shows increasing occurrences of situations where system and BRP imbalance have the same sign. Indeed, those increasing levels of wind power, progressively add BRP imbalance to the system imbalance.

The wind speed profiles also influence the occurrence of imbalance situations. For high wind speeds, situated at the top end of the power curve of a wind turbine, power underestimations are more frequent than overestimations. The chances of forecasting 12 m/s for an actual wind speed of 14 m/s are as high as forecasting a

16 m/s. However, after transformation from wind speed to power, the 12 m/s underestimation has a much more significant impact. For *Windday C*, these situations of underestimation of wind power output predominate, automatically leading to increased occurrences of situations with positive BRP imbalance.

Based on actual figures of the distribution of imbalance costs and using the methodology of this section, a TSO could anticipate systematic biases in forecasts and, if supported by regulation, re-organize the imbalance charges in some way to minimize the societal cost and encourage correct forecasts to be submitted.

5.3.4.4 Additional considerations to the results

When wind power penetration in a system becomes very large, system balancing volumes and prices can become strongly correlated to the wind-related forecast error. If large imbalances coming from wind power were to raise the marginal and average regulation prices higher than under regular circumstances, the imbalance charge might rise accordingly. In this sense, the values calculated above provide a lower bound for real balancing costs.

Changes in imbalance tariff design can lead to changes in the behaviour of BRPs. In this view, the simulations performed above are suggestive of the direction of imbalance costs, rather than predictive in actual magnitude of costs. The strategic behaviour of BRPs is not included in the performed analyses.

Another element that can influence the outcome of imbalance settlements is the considered geographical area. The larger the area, the more probable different imbalances will even out each other. Just looking at wind power output, a geographical spreading of wind farms already offers more benefits in terms of balancing, for as long as the wind speed is not perfectly correlated.

5.3.5 Conclusion on the comparison of four imbalance tariff systems

Different countries have different views on how to charge for imbalances in electricity generation. The imbalance charge rules are especially important when looking at energy sources with a limited predictability such as wind power.

The Belgian, Dutch, French and Spanish imbalance charge rules are compared. Belgium and the Netherlands rely on imbalance charges based on marginal cost pricing, whereas France and Spain use average costs for the calculation of imbalance charges. Apart from this base for imbalance charges, a certain increment on top of the cost is often added, which also varies according to the considered country.

Two approaches have been used for comparison of the effect of imbalance charges on wind power. A first approach looks at the impact of a predetermined forecast error for each period in the 24 hour analysis on wind power and the resulting costs. The second approach investigates the interaction between residual system imbalance and the imbalance stemming from wind speed forecast errors, applying a Monte Carlo algorithm to find a consistent outcome. For both approaches the Belgian system serves as background. Data for spot market prices and marginal and average imbalance regulation prices are taken from the Belgian system.

Two sets of parameters can be distinguished that influence the imbalance costs for BRPs offering electricity from wind power. On the one hand, the imbalance tariff designs of the different countries determine how the imbalance costs of the TSOs are passed on to the BRPs. The imbalance rules based on marginal costs are generally found to result in the highest costs charged to wind speed forecast errors.

On the other hand, demand and wind speed profiles, forecast errors and the total installed wind power capacity also affect imbalance charges from wind-generated electricity. Increasing amounts of installed wind power are found to lead to relatively higher imbalance charges for wind power. The wind speed profile is a determining element, with low wind speed profiles possibly leading to nullifying the obtained revenues. Higher forecast errors obviously also lead to relatively higher imbalance charges.

Comparing the imbalance charges for wind power for the different countries, shows that the Spanish system is the cheapest for BRPs offering wind power. The Belgian imbalance rules have the most expensive outcome. The Spanish imbalance tariff design is based on average cost pricing and does not charge penalties on top of the imbalance costs. The Belgian system is based on marginal pricing. However, the imbalance prices are capped by the average prices and reference market prices in the system, thereby leading to the highest possible charges being passed on to the BRP. The French and the Dutch system lie somewhat in between. Although the Dutch system is based on the higher priced marginal pricing, the lack of additional conditions to the price and the absence of penalties, still make it a relatively interesting imbalance tariff design for wind power. The French system calculates the imbalance costs for the BRP according to the average imbalance costs. However, additional constraints put a cap on the price whereby the reference market price determines the imbalance charges under certain circumstances. Under the performed analyses, the French system therefore shows higher net costs being charged to the BRPs.

The cheapest imbalance tariff design does not reflect what the best solution is in terms of imbalance charges, since this design depends on the policy chosen for the goal that needs to be achieved. The choice between marginal and average cost pricing is to be made taking into account which main objectives need to be achieved. If a BRP is stimulated to avoid imbalances at all cost, marginal cost pricing might prove a better measure. If, on the contrary, imbalances of, for example, wind power are tolerated to some extent, an average cost pricing might not fully penalise imbalances.

Policies supporting wind power integration in electricity generation systems can weigh off the options of reducing imbalance tariffs for wind power or using other support mechanisms for wind power, such as investment subsidies. When the exemptions on imbalance charges for wind power are inspired by unclear motives and not based on actual technical necessities, other support mechanisms that give incentives for the optimal integration of wind power are probably more sound. However, imbalance tariff designs for wind power might have to be rethought to incite BRPs offering electricity from wind power to make the best possible wind power forecasts and to use this forecast in their bidding strategy. At the moment, some imbalance tariff designs might stimulate BRPs to adopt other bidding strategies that maximise their own profits through sub-optimal declaration of wind power forecasts [140; 141; 143].

It has to be noted that in reality the considered geographical area and total system demand will be determining for imbalance charges since all elements that can lead to forecast errors are usually not fully correlated and imbalances will be somewhat evened out. Also, each country's generation mix leads to different merit orders and thereby different reference market prices[84] and marginal an average costs for reserves contracted by the TSO for imbalance management.[85] A larger electricity generation system typically needs more balancing reserves but also has a wider range of power plants that can offer the reserve services.

[84] With the coupling of APX, Powernext and Belpex, spotmarket prices in the three countries are the same when no congestion occurs on the transmission lines [174].

[85] In the analyses made above, the Belgian reference data has been used. A possible way of making a more general comparison is introduced in section 9.4.1.

5.4 Comparison of two different sets of imbalance charges in Belgium: the 2005 and 2006 imbalance rules[86]

In 2006, the Belgian imbalance charge rules underwent some major changes. The method used for comparing the countries' different imbalance charges, also allows for a comparison between the new and old imbalance charge rules in Belgium.

The 2005 rules can be considered to be slightly more arbitrary. Imbalance charges are often determined by predefined minima and maxima, while the 2006 rules follow a more market-based approach. After briefly describing the 2006 and 2005 Belgian imbalance rules, a comparison of both systems is given.

Every occurring imbalance is presumed to be compensated by the TSO. For this compensation, a certain imbalance payment is due to the TSO, just as in the previous comparison of the different countries' imbalance charges. The payment is chosen as to approximate the cost of balancing wind power on the very short term[87]. When the real wind power provision is lower than what has been declared before gate closure, a cost is charged to the BRP. When the imbalance of the BRP providing energy from wind is positive however, the TSO will compensate for that amount.

5.4.1 Elia 2006 imbalance rules

5.4.1.1 The Elia 2006 imbalance rules explained

The 2006 imbalance charges are based on the total imbalance in the zone. The average and marginal weighted costs for Elia to provide additional or decreased production are used to determine the charges to be paid to or received from Elia. The reference market price, multiplied by various indexes, acts as a cap on these values [175].

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[86] This section is based on the conference paper "Luickx, P.J., D'haeseleer, W.D. 2007. Backup of Electricity From Wind Power: Operational Backup Methods Analysed. World Wind Energy Conference 2007, Mar del Plata, Buenos Aires, Argentina October 2-4, 2007."

[87] It can be assumed, however, that the real cost of balancing wind power will be lower than what the BRP pays to the TSO, since in reality transaction costs will occur which the TSO has to recover.

5.4.1.2 Imbalance costs using the 2006 rules

For each of the considered load profiles, corresponding to four different days in 2006 and for each of the four wind profiles, variations on the forecast error have been applied and linked to the actual imbalance costs employed by Elia [176]. The cost is calculated by Elia through the extent to which a BRP deviates its real output compared to the production forecasted during unit commitment. The rules for calculating these imbalance charges for 2006 can be consulted in [175]. When the actual electricity generation by wind power is lower than the forecasted value, a negative imbalance is created and a certain cost needs to be paid to the TSO[88].

In a first analysis, the corresponding hourly imbalance costs from Elia have been linked to the four different load profiles used. Each of the four demand profiles introduced in 4.2.5 is taken from actual demand data from Elia and represents a certain day. The imbalance costs used in this analysis are the ones corresponding to the same dates. Moreover, the forecast error, which is distributed normally, varies between a standard deviation of 0 and 0.3. This reflects forecast errors of 0%, 10%, 20% and 30%, related to the installed amount of wind power. The reason for the forecast error being based on the installed wind power is that this way, a certain amount deviation from the forecasted value has the same probability of occurring at high wind power output than at low output. Possible interpretations for an increasing forecast error have to be found in the available wind speed forecasting tools and the moment of gate closure.

The results for the load of day 3 and the wind profile of windday C are shown in Figure 34 as an illustration. It is obvious that a 0% forecast error does not generate any additional cost.[89] The cost difference, relative to the base run where wind is perfectly forecasted, rises with the total amount of installed wind power. Another element that comes forward is the cost difference rising with more inaccurate forecasts. Since the costs for each MWh of imbalance is unaffected by the extent of this imbalance, the difference between a 10% and a 20% forecast error is of the same size than between a 20% and 30% error. Just as in the previous section, the

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[88] This imbalance cost is based on the reference market cost for electricity and calculated on a quarterly basis. An hourly average has been taken for this exercise. The negative imbalance cost is higher than this market cost, while a positive imbalance cost, where the BRP gets paid for an electricity generation, exceeding the forecasted amount, will be smaller than the market cost.

[89] The demand and wind speed profiles are introduced in section 4.2.5 and can be consulted on the last page of the thesis for easy reference.

chosen wind profile has an impact on the difference in cost as well. Higher overall wind power profiles generate higher cost deviations.

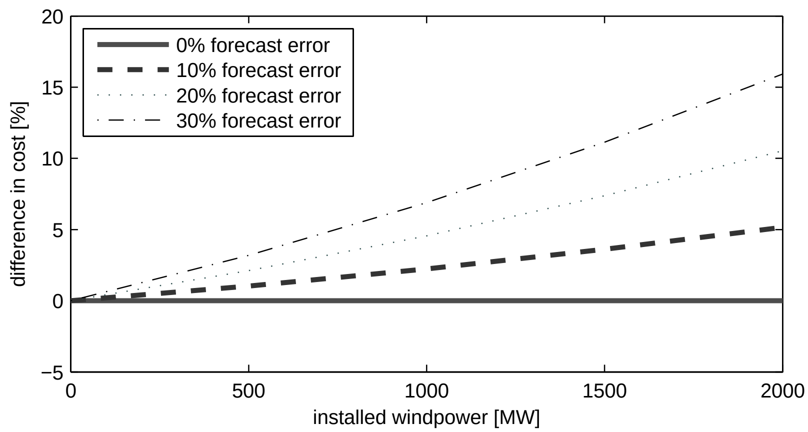

Figure 34: Relative increase in operation costs, expressed in percentages, of the load pattern of day 3 for increasing amounts of installed wind power applied to the profile of windday C.

With these analyses, no statement can be made regarding the effect of the load profiles on the additional cost since four corresponding but different imbalance costs are assumed for the four different load profiles. Therefore, the same analysis is repeated applying a same imbalance cost profile for each of the considered days. For this exercise, the lower the overall load during a day, the higher will the cost difference be, compared to the base case without forecast error.

5.4.2 Elia 2005 imbalance rules

The 2005 imbalance rules were based on the day-ahead APX prices with caps on maximum and minimum tariffs. The determination of the charges for wind power depend on the total (positive or negative) imbalance of the zone on the one hand and on the (positive or negative) imbalance of the individual BRP providing the wind power on the other hand. The formula used for calculating the imbalance charge also depended on whether the imbalance, expressed in MWh, crossed the threshold of 10% of the size of the BRP, applying higher charges for these considerable imbalances. A distinction was also made between daytime and night-time charges.

Finally, higher overall limits applied for the first and last three months of the year [177].

5.4.3 Comparing the 2005 and 2006 imbalance rules

In a next step, the Belgian 2005 imbalance rules are compared to the 2006 rules. To offer a ground for comparison, data from the year 2006 have been used, applying respectively the 2005 and 2006 imbalance rules to the 2006 imbalance data and day-ahead market prices. The same forecast error, wind power and load profiles have been used for both analyses. Only the imbalance charges and corresponding backup costs differ.

When considering imbalance charges by a TSO, it is important to distinguish between negative and positive imbalances for the entire system as well as for individual BRPs. The 2005 and 2006 imbalance rules generate clearly distinguished imbalance charges. For the considered four typical demand profiles, but also when looking at full yearly datasets of 2005 and 2006, a general trend is that the 2006 negative imbalance charges[90] are slightly higher than the 2005 charges. However, this is compensated by the likewise higher average payouts to BRPs who provide positive imbalances to the TSO.

It can be said that for the 2005 imbalance system, the effect of wind imbalances does not directly interfere with the imbalance charge calculations. Often a fix set price is being charged for imbalances. Only a secondary effect of wind power imbalances on the APX price might have a slight effect on the dynamics of this price setting, which is not explicitly included in this exercise. The 2006 imbalance rules make charges dependent of the imbalance of the entire system rather than individual imbalances. This reflects the actual situation for every fifteen minutes and is closer to the actual cost of the imbalance. It has to be borne in mind however that all values are highly dependent of the context and not only average charges should be looked at. The wind power profiles play an important role as well. The 2005 charges are lower during night-time, when wind power generation is considered to be less fluctuating or on a lower level of production, but relatively higher during daytime. In the considered scenarios for example, *winddays 3* and *4* show a considerable higher

[90] Negative imbalance charges refer to payments by the BRP to the TSO as a result of the BRP's contribution to the total negative imbalance of the system. Positive imbalance charges refer to payments from the TSO to the BRP due to the BRP providing more electricity than foreseen.

output during daytime. This coincides with, at least for European data[91], with wind being more active during daytime than at night. This will effect the total outcome of the cost for wind power.

Some results of the performed calculations can be observed in Figure 35 and Figure 36, representing results for two different wind profiles with the load profile of *day 2* and *day 4* respectively, with corresponding imbalance costs according to the 2005 and 2006 rules and this for wind power integration ranging from 0 to 2000 MW. Several general elements that are true for both imbalance charge rules can be illustrated by these figures. First of all, it is clear that with a higher overall wind power profile, such as *windday 3*, the corresponding backup cost shows higher values than, for example, in *windday 4*. Moreover, the backup cost increases with lower overall load profiles. Figure 36, representing the evolution of the relative cost for the lower load profile of *day 4*, clearly illustrates this. Finally, the cost rises more than linearly with increasing amounts of installed wind power.

The most important observations relate to the comparison of the imbalance rules of 2005 and 2006. From a first point of view, no clear trend can be observed. Depending on the specific imbalances of the zone during the day and of the employed wind profile, sometimes the 2005 rules generate the higher additional cost for wind, while other times the 2006 rules do. When looking at more extensive datasets however, mostly the 2005 rules coincide with higher backup costs. This is surprising since at the same time the charges for negative imbalance are usually lower applying the 2005 rules than when using the 2006 rules. As mentioned above, the reason is twofold. On the one hand, the higher negative charges are compensated by higher positive imbalance remuneration coming with the 2006 rules. On the other hand, the lower average imbalance charges with the 2005 rules are to a large extent due to the abovementioned reduced charges at night, typically when wind power operates on a lower level. The 2005 charges during daytime do not differ a great deal from the 2006 charges during daytime.

[91] As previously demonstrated in section 1.4.1.4

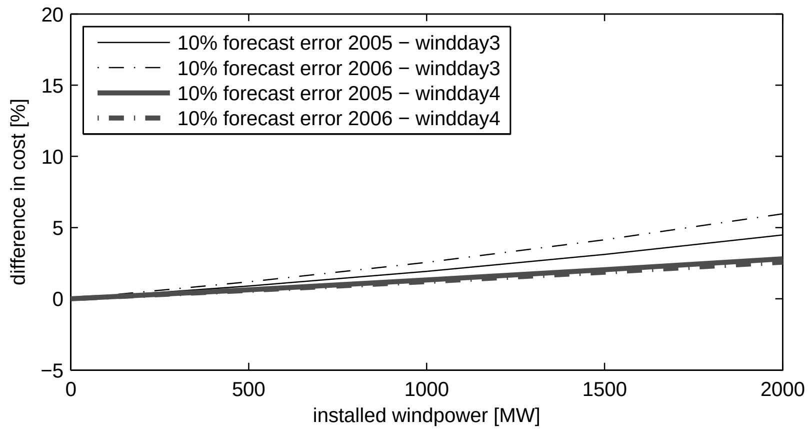

Figure 35: Comparison of the difference in cost for 2005 and 2006 imbalance rules. Load profile of day 2 *and wind profiles of* winddays 3 *and* 4 *are used*

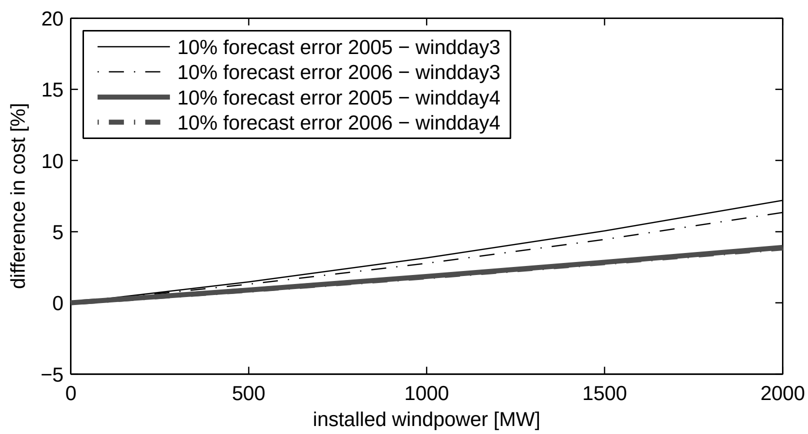

Figure 36: Comparison of the difference in cost for 2005 and 2006 imbalance rules. Load profile of day 4 *and wind profiles of* winddays 3 *and* 4 *are used*

Not depicted in the above figures but still interesting to observe, is the evolution of the backup costs with increasing forecast errors. Taking a standard deviation of 20% instead of 10%, the 2005 rules become increasingly expensive for the wind balancing. Higher imbalances cross the thresholds of the 2005 imbalance rules more frequently, leading to considerably higher imbalance charges. The 2005 charges will rise in relation to the 2006 charges. That explains an upsurge in 2005-based costs once higher forecast errors are assumed. It can be said that, with increasing uncertainty on the forecasts for wind power, the 2006 imbalance rules become more to the benefit of wind power integration.

5.5 Conclusion on dealing with unpredictable wind power and forecast errors on the short term

A thorough understanding of the backup of wind power in an electricity generation system is a crucial element in the study of wind power. The focus in this chapter is put on the operational backup and the short-term issues of wind power integration into a system.

Most important parameters that affect the short-term operation of backup of wind power are the load profiles, the wind speed profiles and the total amount of installed wind power. Different analyses are performed to investigate how short term imbalances due to forecast errors can be coped with and which impact they have on the operation of the system.

It is important to distinguish between the two important phases in the short-term operation of electricity generation systems with imbalances coming from wind power, namely the unit commitment and the dispatch phase. The former takes place before gate closure and leaves more options open to the system to foresee certain reserves. The latter happens at the actual moment of operation. Once the dispatch phase is reached, fewer options are open for dealing with possible imbalances. The BRP is responsible for the balance in his perimeter. The TSO manages the imbalances the BRPs are not able to control and charges accordingly.

To consider both measures that can be taken well ahead and the imbalance settlement by the TSO, different analyses are performed. A first analysis considers all of the wind power forecasts to be completely unreliable and foresees a 100% coverage of this forecast by additional reserves. The innovation of this approach is that it allows to get an idea on what the most costly scenario for wind power backup with no loss in reliability can be. For small levels of wind power, contracting additional reserves does not pose much extra effort. However, for higher amounts of wind power, costs begin to rise steeply.

A second point of view is introduced by investigating the impact of imbalance tariffs to the wind power generators through the settlement by the TSO. Four countries are compared to one another, demonstrating that the design of the imbalance tariff system does have its impact on the imbalance costs from wind power. The 2005 and 2006 imbalance tariff systems of Belgium are compared to one another as well. The exercise is useful in the sense that the Belgian TSO had its imbalance tariff redesigned at the start of 2006. The novelty of this approach is the comparison of the imbalance tariff designs, not only in terms of the actual rules but also in terms of impact on wind power imbalances. Countries' imbalance tariffs have already been compared before, but usually based on average values from historical data and never applying the actual dynamic imbalance rules. It is clear that many differences exist and that great care should be taken in the choice of imbalance tariff design, especially in the light of the movement towards the harmonization of power markets.

In the analysis of the cost impact of additional reserves for wind power and the payment of net imbalance charges, several parameters are found to affect the final outcome. Both the wind profile and the total amount of installed wind power, together defining the amount of electricity produced by wind power, are positively related to the relative cost increase.

The exercise presented so far allows for a better insight in the elements influencing the relationship of both methods to one another. A certain value is put on the short term availability of backup. The more ahead a backup is foreseen, the more options remain available and the cheapest it will turn out to be. Therefore, really short term balancing backup should be avoided whenever possible. On the other hand, it is impossible to foresee the entire backup ahead so that the balancing by the TSO will always be necessary. A good balance will lie somewhere in between the use of all the available options.

6. STORAGE OF ENERGY FROM WIND POWER[92]

According to Bathurst and Strbac [178], the value of wind energy is a complex function of the electric power and imbalance price, and wind speed forecasting error. Therefore, it is important to get a clear view on the functioning of energy storage since it will impact both the energy price and balancing of the system, while compensating for possible forecast errors.

Energy storage is one of the domains where vast improvements for the efficient use of primary energy carriers could be achieved. This is particularly true for electrical energy due the continuous need for balance between demand and supply. Knowing electricity generation closely needs to follow demand, leads to continuous adaptations in the operation of the electricity generation system. For optimal use of this system however, a constant output, using predominantly the most efficient power plants for electricity generation, would be appropriate. Storage methods of generated energy can flatten out fluctuations in generation by storing the energy when supply is high and demand low and release it to the system when demand is high.

Storage of energy can be used for stockpiling to ensure security of energy supply or as peak-shaving. In combination with the electricity generation from intermittent renewable sources, such as wind power, storage options can transfer energy supply in time to moments where demand is more critical. Nowadays, wind power is seen as a resource that needs to be balanced, which induces additional costs to the system. Intelligent storage options could constitute an efficient means of balancing and increase the controllability of intermittent energy sources.

In the following, two storage options are analysed in relation to their impact on wind power integration in electricity generation systems. Firstly, the pumped hydroelectric storage system (PHES) is being looked at. The PHES can be used for two purposes, namely peak shaving and balancing. An analysis is made on how to most optimally

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[92] This chapter is based on the submitted article "Luickx, P.J., Delarue, E.D., D'haeseleer, W.D. 2009. The examination of different energy storage methods for wind power integration. Submitted for review in Renewable Energy." and on the conference paper "Luickx, P.J., Delarue, E.D., D'haeseleer, W.D. 2008. The examination of different energy storage methods for wind power integration. GlobalWind 2008, Beijing, China October 29-31, 2008."

allocate the available PHES capacity over both functions, taking the impact on operational costs and system reliability into account. Next, the combination of wind power with heat provision through heat pumps with thermal storage is investigated. This storage option looks into a different usage of electricity from wind power and how this can help reducing overall GHG emissions.

In the first section, different energy storage methods are briefly described and a selection is made of two specific options for the storage of energy from wind power. Subsequently, the results of the performed analyses on PHES and heat pumps, using the MILP model applied to the Belgian electricity generation system, are discussed. Finally some conclusions are drawn.

6.1 Energy storage methods

A variety of energy storage options is available at the moment albeit most of them do not allow massive storage of electric energy. More methods are continually being developed and existing ones are improved. This section briefly discusses some of the more common storage options.

Firstly, the primary control of an electricity generation system could be considered as some kind of storage option for the system [16]. The turbine speed or governors are used for providing this reserve. This reserve is based on the kinetics of the turbine and is inherently available in power plants. It is referred to as the inertia of power plants. Even wind turbines have the capacity to provide primary frequency control [179]. It operates instantaneously and is being used automatically in the system. However, the following analysis concentrates on storage in the timeframe of hours and the shifting of energy provision over longer periods of time.

Next, a range of electricity storage methods with capacities ranging from a couple of kW to a few hundred MW can be applied [37; 180]. Small-scale compressed air energy storage (CAES) [181], flywheels [182], conventional batteries and supercapacitators are examples of the former. PHES [183], large-scale compressed air energy storage [183; 184] and redox flow batteries belong to the latter category. Although PHES and CAES are, strictly speaking, only indirect electricity storage means, through potential energy of water and enthalpy of air, respectively, they are categorised under electrical storage methods nevertheless.

Furthermore, a number of non-electric energy storage systems are available. The storage of primary energy carriers constitutes an obvious way of storing energy.

Keeping reserves of oil, coal or gas is implicitly used for both peak shaving and preservation of security of energy supply [185; 186]. For gas, apart from regular storage in large reservoirs, the line-pack method, where available the gas pressure in pipelines can be utilised for storage purposes, is a useful tool as well [187; 188].

Thermal energy storage also belongs to the non-electric energy storage methods. Three main categories can be discerned for thermal storage, namely the sensible, latent and thermochemical heat storage [189; 190]. Sensible heat storage, traditionally used for relatively short time spans, can be split up in liquid or solid media storage. Water reservoirs are a typical example of this liquid media storage, and are especially used for lower temperatures [190]. Latent heat storage methods provide much higher storage densities, with a smaller loss of temperature between heat storage and release [191]. A wide range of phase change materials (PCM) can be used as energy carriers [191; 192]. PCMs typically change from the solid to liquid or liquid to gas phase, absorbing heat or vice versa when releasing heat. Thermochemical storage is based on the energy absorbed and released during reversible chemical reactions, when breaking and reforming molecular bounds [189]. The energy is stored within the chemical bounds [193].

Within conventional electrical batteries, the plug-in hybrid car deserves special attention. Large numbers of plug-in hybrid cars being connected to the grid in combination with smart metering in each household, could offer an efficient means of storage if properly integrated into the system and well controlled. The stored electricity in the cars' batteries can be used in two ways. It can either serve as power source for the vehicle or it can provide electricity back to the grid when needed. However, the impact of plug-in hybrid on the distribution grid is subject to many conditions and should not be presented as a straightforward storage solution [194].

Plug-in hybrid cars could be considered an option for efficient energy use on the electricity demand side. The plug-in hybrid electric vehicle is commercially available. A number of companies have already been designing and testing plug-in hybrid vehicles [195-198]. Hybrid electric vehicles combine a conventional internal combustion engine, powered by gasoline, diesel or biofuel, with an electric motor, leading to increased fuel efficiency. The batteries can be charged through electricity generation of the engine or with electricity of the distribution net [199]. Batteries constitute the main limitation in purely electric vehicle technology, hence the combination in the hybrid philosophy with internal combustion engines for large driving distances. Indeed, current battery technology only allows driving for short to medium distances (up to 250 km). Most of the batteries used for hybrid electric vehicles nowadays are nickel-metal hydride batteries (NiMH). They have twice the energy density and three times the power density of a lead-acid battery. They can handle many cycles of charging and discharging. New recent developments of lithium-ion batteries and supercapacitors give the possibility to recharge very quickly, to have high energy power densities and a longer lifetime [200]. By combining the massive charging of batteries for plug-in hybrid cars with the peaks in electricity generation from wind power, the variability of the wind power output could be reduced. By applying the principle of smart metering and real time pricing, owners of plug-in hybrid cars could be stimulated to charge their cars whenever a negative forecast error occurs. The same reasoning can be applied to positive forecast errors, leading to a partially wind-steered pricing, eventually leading to reduced impacts of the uncertainty of wind power. Because of the still unclear picture of plug-in hybrid car electric storage into the overall system, this case is not included below.

Not all storage options enumerated above are suitable for better integration of wind power. Therefore, the two feasible options, PHES and heat pumps, are selected as study subject due to the relative maturity of their technology and their economic viability.

6.2 Study of two energy storage methods for wind power

This section describes the approach used for the examination of the two chosen storage options in combination with wind power introduction. Successively, the PHES and heat pump options are discussed.

For both analyses, the Belgian electricity generation system is used as a reference, and simulated applying the MILP model introduced in section 4.2.

6.2.1 Pumped hydroelectric storage

Numerous studies have already dealt with the combination of wind power and PHES. Benitez et al [201] investigate the use of hydropower and PHES as an approach to reduce costs for the operation of the system with increasing amounts of wind power. They look at how the variability of the wind power output can be compensated by different combinations of peak power and additional hydropower, new pumped storage capacity or increasing the size of existing reservoirs. Another study considers the pumped hydro storage as a unit to cover demand whenever it exceeds supply

[202]. The approach adopted by Castronuovo and Peças Lopes considers a wind-hydro system as one entity to be optimised, with perfect forecast of wind power two days in advance [203].

Two functions of the PHES are considered in this study. On the one hand, PHES can be used for peak shaving that is assigned in the unit commitment phase, thereby acting as a de facto intra-day price arbitrage system. On the other hand, PHES can have a balancing function in the dispatch phase of the system operation. In this second case, a certain capacity of the PHES is reserved for short-term compensation of imbalances due to erroneous wind power forecasts. In what follows, the planning of the PHES during unit commitment to allow for cost-optimal usage of the system will be referred as "PHES for peak shaving". The reservation of PHES capacity to be used during dispatch whenever a forecast error on the wind speed prediction is made will be referred to as "PHES for balancing".

In Belgium, the pumped hydro station of Coo can indeed be used as contributor to secondary reserve. Both options are evaluated in the light of the variability and unpredictability of wind power. Not only the cost reducing benefits of the PHES on wind power are considered but also the opportunity cost for the PHES not to be available for other tasks in the system.

The contribution of the PHES to either one of these services is taken to vary and the effect of this choice is investigated in terms of technical difficulties and cost savings. The peak shaving within the system will see to it that peaks in demand, after deduction of the electricity generated by wind power, are flattened out. The balancing services of the performed simulations are focussed on wind power forecasting errors. Every MWh of negative forecast error, which refers to more wind being available than predicted, leads to the PHES pumping up water in its reservoirs. Every positive forecast error uses the stored energy in the reservoirs first, before other reserve mechanisms are drawn upon. This way, the imbalances induced by wind power are maximally covered through PHES usage, which will have a positive impact on the loss of load expectancy (LOLE) of the system. This LOLE is calculated as described by [110].

6.2.2 Wind energy stored as heat through heat pumps

When looking at electricity from wind power as a pure energy source, it could also serve as a means for heat provision. As discussed above, electricity is not easily stored. Heat however, can count on proven storage technology. For efficient heat production through wind power, accumulation heat pump heating with a seasonal performance factor (SPF) of 4 is considered [204].[93] This is in line with the GHG emissions saving and generation mix analyses that were performed in [92] and [205] and also consistent with technical data from proven heat pump manufacturers [206]. The heat is assumed to be stored, with an average loss of 10%, in large reservoirs.[94] For the wind generation to be useful in this heating context, a certain amount of heat demand needs to exist. The heat demand can be seen as coming from large buildings or a neighbourhood residential heating system. All the energy generated by the wind turbines is now being redirected to heating purposes with efficient storage. Hence, the heat demand from the buildings and the supply from the heat pumps is decoupled in time. This way, both the variability and unpredictability issues of wind power are avoided since the wind power output will not directly affect the actual operation of the electricity generation system.

The heat that is generated by heat pumps operating on wind energy is assumed to be an alternative to heat generated by gas-fired boilers with an efficiency of 100% and emissions of 211 g/kWh_{prim} and oil-fired heating systems with an efficiency of 80% emitting 276 g/kWh_{prim}. The data are consistent with the ones used in [92] and [112]. The emissions and costs related to the operation of these conventional units are avoided when considering wind power as the heat source.

Some reservation needs to be made whether the distribution grid can cope with large amounts of heat pumps needed to use the electricity from the wind turbines. The distribution grid needs to be well-designed to allow the connection of many heat pumps. Implicitly, the use of microgrids is assumed in this exercise. An additional use of (reversible) heat pumps, not examined in this exercise, is the application of heat pumps for cooling. A more efficient use of heat pumps during the year can be achieved when considering both heating and cooling qualities of heat pumps.

[93] A SPF of 4 corresponds to a ground source heat pump. A SPF of 3 would be corresponding more to an air source heat pump.

[94] As discussed above, several thermal storage technologies can be used to store the heat from the heat pumps. Depending on the amount of time heat needs to be stored, the conditions the heat pump/ storage system operates and the allowed losses, different technologies can be chosen.

6.3 Results of the two storage options analyses

When discussing the various results from the simulations, it has to be borne in mind that they do not necessarily reflect real-life situations. They should rather be interpreted as analytical exercises that help understand the issues raised by wind power in combination with the two considered storage options.

6.3.1 Impact of the use of pumped hydroelectric storage

The impact of PHES is evaluated in two distinct ways. Firstly, only its peak shaving ability in an environment with perfect forecast is looked at. Next, also the balancing potential that is used in a world with forecast errors is studied.

6.3.1.1 Pumped hydro storage used for peak shaving

PHES allows for a more optimal usage of the available generating units through peak shaving. This is not only useful for absorbing peaks in electricity generation from wind turbines; it can be used in combination with the entire system. The application of PHES for peak shaving is modelled as one of the parameters within the MILP model to allow for a cost-optimal functioning of the electricity generation system.

By using the stored energy, smaller flexible power plants or power plants with relative expensive operating characteristics coming later in the merit order can be used less frequently. The storage leads to reduced repeated starting up and shutting down of power plants and to cost savings in general. Moreover, peak shaving can be seen as a substitute for installed capacity in the system, especially peaking units. If PHES is consistently used for shaving the peaks in demand, the total needed generation capacity is reduced. The pumped hydro station of Coo is not only useful in the operation of the Belgian system, it is also necessary to cope with the increasing demand in electricity. If the capacity of the station is severely lowered, problems in terms of meeting electricity demand can occur.

The inclusion of wind power can have diverse impacts on the effectiveness of PHES. The combination of available generation, demand and wind power profile determines whether the wind power will positively or negatively affect the cost reduction capacity of PHES. In situations where the wind power profile helps reducing the variability of demand, PHES can be used more effectively. Not only the demand lows but also the wind power highs can be used for pumping up water in the reservoirs that is later released when aggregate demand is high and the use of a more expensive combined cycle power plant can be avoided. This combination of PHES and wind power is a strong asset in cost reduction and GHG emissions reduction in an electricity generation system. Important lows and highs in the aggregate demand, considering wind power as negative demand, can be compensated by the PHES while still preserving the beneficial characteristics of wind power, namely zero fuel usage and the certainty that in the future the operation of wind turbines is not subject to fuel price changes. The addition of wind power has the further advantage that wind power will overtake coal-fired power plants as the cheaper energy source. Indeed, just temporarily disregarding wind energy, in the current operation of many systems, coal-fired power plants operate in base load. Using PHES to shave peaks usually results in optimised use of these plants, replacing more expensive, be it less polluting, peak load gas-fired power plants. This however results in higher overall emissions [207]. When wind power is introduced and it replaces coal-fired power plants as the marginal power plant, the GHG emissions can be drastically reduced.

In other situations, however, when wind power and demand are positively correlated, wind power can reduce the value of having PHES. The introduction of wind power in a system can cause opportunity costs for PHES when both wind power and PHES have the same function, namely effectively shaving peaks in electricity demand. This mainly occurs in situations where a PHES shaves a peak that otherwise would have to be covered by an expensive power plant. In a situation with a significant amount of available electricity from wind power on that same peak, electricity generation by this relatively expensive power plant is partly made obsolete by wind power. The PHES therefore cannot offer the benefit of a serious cost reduction anymore since electricity generated by wind power has already replaced the electricity generation from the expensive power plant. This can be seen as an opportunity cost of wind power. This opportunity cost is however compensated by the reservoir of the PHES still holding more water that can be used at a later time. The opportunity cost is analogous to the conclusion of [208], stating that the value of regular hydropower decreases when wind power becomes more important.

6.3.1.2 Pumped hydro storage used for peak shaving and balancing

The fraction of the PHES that is attributed to peak shaving and to balancing purposes affects the operation of the electricity generation system. Figure 37 shows the impact of varying the fraction of PHES services assigned to peak shaving for a specific case of demand and wind speed profile. The operational cost is proven to benefit from additional peak shaving. The fraction of PHES assigned to balancing is inversely related to the fraction on peak shaving; for each increase in fraction of PHES for peak shaving, the fraction for balancing is reduced to the same extent.

Since Belgium is made up of a wide range of electricity generation options, with significant differences between the cheaper and more expensive power plants, peak shaving has a positive effect on the incurred operational costs. On the other hand, increasing the fraction of PHES for peak shaving automatically reduces the fraction for balancing wind energy. This in turn leads to adverse effects on the LOLE, at least from a certain point on. As will be recalled, the LOLE is one of the possible ways to quantify the reliability of an electricity generation system. By using the PHES for balancing the negative and positive wind speed forecast errors, a great deal of uncertainty is done away with. This reduces the stress on the available reserves in the system, which defines the reliability and which will influence the LOLE. Using PHES for balancing, furthermore has a positive impact on reserve costs since fewer classical reserve-providing power plants have to balance the wind forecast error, therefore leaving the cheapest units available for other reserve provision in the system. However, in this and most other cases involving higher fractions of PHES for balancing, the savings obtained in reserve provision are counterbalanced by the loss in peak shaving potential. Similar results are obtained for other combinations of wind power, demand profiles and forecast errors.

In Figure 37, a rise in LOLE is apparent beyond 60 % PHES for peak shaving. At the simulation point of 80 %, 20 % of the PHES is used for balancing. This rise in LOLE has to do with the balancing potential of the PHES being completely used, thereby having to rely on additional reserves from other reserve capacity in the system. By depending on other power plants than the PHES for providing reserve for wind power output imbalance, fewer reserves are available for other possible imbalances in the system. This leads to a reduction of adequacy, reflected by an increase in LOLE. For the peak shaving fractions equal or below 60 %, still enough balancing potential of the PHES is available for the particular case of Figure 37 with a certain wind and demand profile and 2000 MW of installed wind power.[95]

When interpreting Figure 37, it is important to bear in mind that the fraction of PHES for peak shaving is inversely proportional to the fraction of PHES for balancing, as also illustrated in Figure 37.

[95] The demand and wind speed profiles are introduced in section 4.2.5 and can be consulted on the last page of the thesis for easy reference.

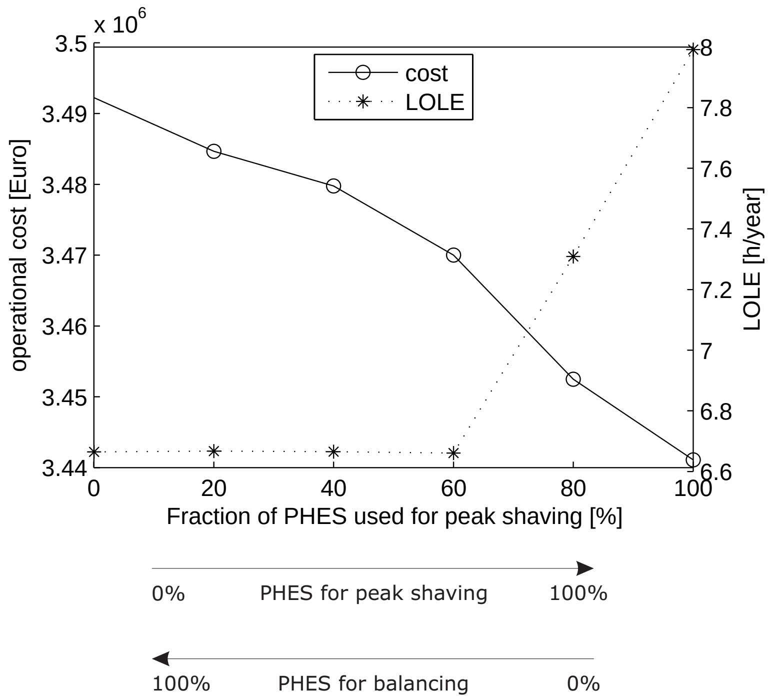

Figure 37: The impact of changing the fraction of PHES for peak shaving on operational cost and LOLE for the entire system. The case represents demand profile Day 1, wind profile Windday C with an installed capacity of 2000 MW wind power, for a standard deviation of 2 m/s on the wind speed forecast error. The fraction of PHES for peak shaving is inversely proportional to the fraction of PHES for balancing.

It has to be noted that the combined effect of low wind energy provision and low fractions of PHES for peak shaving can severely impact the functioning of the electricity generation system. In extreme cases, the simulation model does not find any operating schedule that can cover the demand. The solution for the MILP solver becomes infeasible, referring to insufficient generation capacity in the system. This is represented in Figure 38, where the combination of the high demand profile of Day 1 and the low wind speed profile of *Windday A* results in infeasible options for low fractions of PHES for peak shaving. The effect is higher for low levels of installed wind power capacity. Higher fractions of peak shaving and a higher wind power output can solve this problem and lead to feasible solutions.[96]

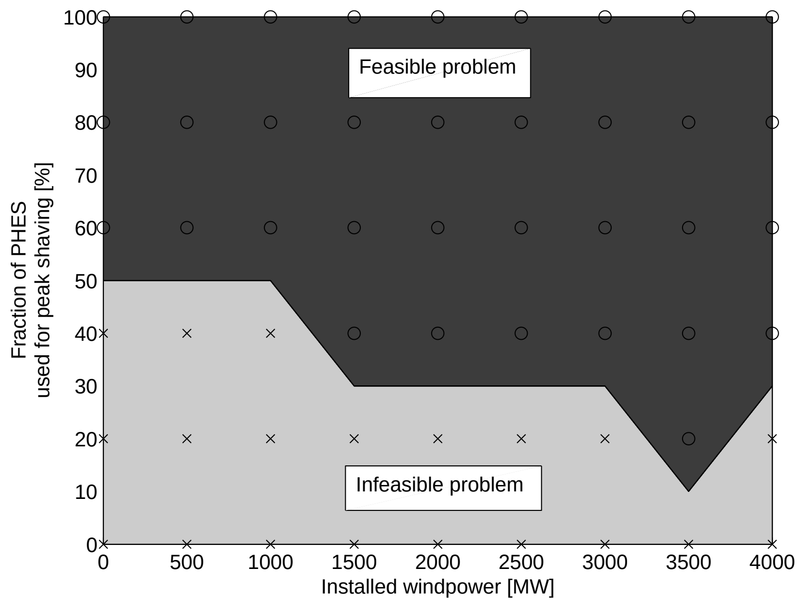

Figure 38: The feasible and infeasible solution regions are marked, according to the fraction of peak shaving and the amount of installed wind power. Case for demand profile of Day 1, wind speed profile of Windday A, and a standard deviation of 1 m/s on the wind speed forecast error.

Figure 39 shows the actual impact of wind power introduction on the operational cost, assuming a 60% fraction of PHES for peak shaving, as a function of installed wind power. For increasing amounts of wind power, more operational cost reduction can be obtained compared to a situation without any wind. Most important reductions are noted for the high wind speed profile *Windday C*. When increasing the forecast error from 1 m/s to 3 m/s standard deviation, problems arise due to the system not being able to generate sufficient electricity to cover the imbalance coming from the error. This is depicted by the circles in Figure 39 showing the limits for wind

[96] The reason for a rise in the infeasible region from 3500 MW to 4000 MW has to do with the dynamic simulation of the system. Although the 4000 MW wind power scenario has more generation capacity than the 3500 MW one, at the same time, fewer regular power plants are activated because of the massive amount of wind power, thereby reducing the possibilities of the system to cope with demand without higher levels of peak shaving from the PHES.

power capacity, taking into account the given standard deviation. The situation for the 3 m/s standard deviation deteriorates when 100% of the PHES is assigned to peak shaving, thereby leaving less opportunity for balancing and putting more stress on the reserve provision in the system. This is show in Figure 40.

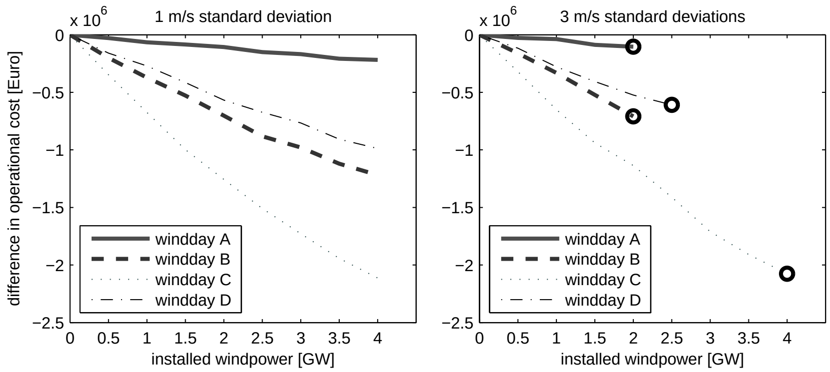

Figure 39: Operational cost savings of wind power introduction for varying amounts of installed wind power and four different wind speed profiles. The left figure shows a forecast error with a 1 m/s standard deviation; the right figure has a 3 m/s standard deviation. For demand profile of Day 1 and a fraction of 60% PHES for peak shaving.

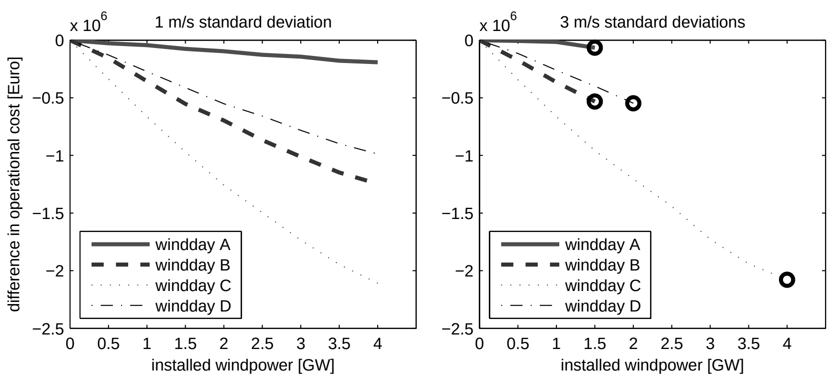

Figure 40: Operational cost savings of wind power introduction for varying amounts of installed wind power and four different wind speed profiles. The left figure shows a forecast error with a 1 m/s standard deviation; the right figure has a 3 m/s standard deviation. For demand profile of Day 1 and a fraction of 100% PHES for peak shaving.

The differences in cost between Figure 39 and Figure 40 are not significantly large. The system can still cope in a cost-efficient way with a 1 m/s standard deviation on the wind speed without the need for 100 % availability of PHES for peak shaving. In some circumstances, when not all of the peak shaving potential needs to be used, it is even more cost-efficient to uphold a certain fraction of PHES for balancing purposes. There is a difference in cost savings potential for the 3 m/s forecast error, especially with the high wind speeds of *Windday C*. In this case, the added variation of wind power becomes such that all of the available peak shaving capacity is used for a cost-efficient operation of the system. When lowering the fraction of peak shaving, less cost reduction can be achieved. Since the fraction for balancing with PHES is raised at the same time however, wind power can be more easily integrated in the system, as observed by limits on installed wind power occurring at a later stage for the wind speed profiles of *Windday A, B* and *D* in Figure 39 than in Figure 40.

It is important to find the right balance between using the PHES for peak shaving and for balancing. Higher fractions for peak shaving facilitate the operation of the system in meeting the demand. As already indicated above, this is especially necessary for low levels of wind power output. However, at the same time the corresponding lower balancing potential brings about more problems for integrating large amounts of wind power. Keeping a higher fraction of balancing services within the PHES results in the opposite effect. Problems in meeting demand arise sooner when faced with high demand and low wind energy levels, while the integration of large amounts of wind power is facilitated. Keeping these opposite effects in mind, it is possible to find a good equilibrium between using the PHES for peak shaving and for balancing. It depends to a large extent on the expected levels of wind energy and on the required reliability levels for the electricity generation system. For considerable amounts of wind energy and for large expected forecast errors, a relative higher share of balancing services is advisable. When low wind power output is anticipated, the fraction of PHES towards peak shaving should be increased.

6.3.2 Impact of the use of heat pumps and heat storage

Applying the electricity from wind power for driving heat pumps, results in shifts in the operation of the electricity generation system. Two scenarios are considered. In both, a total of 500 MW of wind energy is installed and the four wind speed profiles *Winddays A* to *D* are applied using the demand profile of *Day 1*.

In the first scenario, illustrated as the lighter coloured bar in Figure 41, all of the wind energy is used as input for the heat pumps. The consequence is that the electricity generation system has to meet the other electric demand without being able to use wind power. In the second scenario, all of the produced wind-generated electricity is injected into the electricity grid.

In the second scenario, wind power helps meeting demand and outperforms more expensive and more polluting power plants. Therefore, both the GHG emissions[97], as represented in Figure 41, and the operational costs of the electricity generation system are lower than in the first scenario. However, with the wind power being exclusively used in the electricity generation system, the heating that was performed by heat pumps in the first scenario now has to originate from conventional heating. The additional GHG emissions and operational costs coming from gas- and oil-fired boilers have to be added to the emissions of the second scenario. When considering the emissions from the electricity generation system and the additional heating as a whole, thereby adding the additional emissions from conventional heating to the emissions from electricity generation, the second scenario emits more than the first. GHG emissions savings of the heat pump scenario compared to gas-fired boilers range from 0.14 % for the low wind power profile linked to *Windday A* to 2.5 % for *Windday C*, compared to the GHG emissions of the electricity generation system for the simulated day. The savings are even more important when the heat has to be produced by oil-fired boilers, leading to emission savings from 0.63 % to 8.2 %.

The same conclusions can be drawn regarding the operational costs savings, where the wind power - heat pump combination is replacing the use of conventional heating. The first scenario, using the wind energy to drive heat pumps also results in lower overall operational costs. The observable changes in GHG emissions and cost savings apply to the demand profile of *Day 1;* for the other demand profiles as well, the wind-power-driven-heat-pump scenario usually leads to GHG emissions and operational cost savings in comparison with the scenario where all the wind energy is used to meet electricity demand.

[97] Apart from GHG emissions, other emissions such as NO_X or SO_X emissions are important to consider as well. As argumented in the aim and scope of the thesis (section 0.2), GHG emissions constitute the main focus in terms of emissions in the electricity generation system and are therefore used as an investigation parameter.

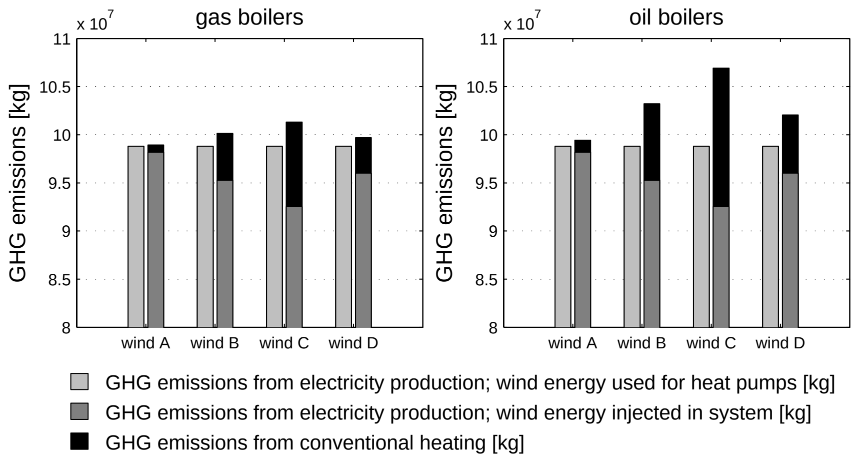

Figure 41: The GHG emissions of the heat pump scenario (the left bar of each pair) and the scenario with additional heating by gas- or oil-fired boilers, where the produced wind energy is injected in the system (the right bar of each pair). The demand profile of Day 1 is used with 500 MW of installed wind power.

The results are not only important in terms of GHG emissions and cost savings. The use of heat pumps to absorb the generated electricity from wind power also dissipates the intermittency impact of wind power. Both the uncertainty of wind speed forecasts and variability that wind power imposes on the system can be avoided, as long as the produced heat is used appropriately[98]. The wind energy is not injected in the electricity generation system anymore and will not contribute to any related integration issues.

6.4 Conclusion

The two storage options that are considered show that the intermittency of wind power need not negatively influence the operation of the electricity generation system. The combination of different storage methods can help improving a good functioning of the system with considerable amounts of wind power.

[98] This is however only from the point of view of the electricity from wind power. In reality, once the heat pumps are in use, heat also needs to be provided during long periods of low wind speeds. When not enough heat has been stored, it is possible that other sources of electricity need to be addressed for the operation of heat pumps.

The PHES can offer peak shaving and balancing services, both useful in terms of wind power integration. A good distribution needs to be found between these services, based on the expected amount of wind energy, taking into account the advantages of each option. These advantages are mainly situated in the cost savings for electricity generation or in the reduction of LOLE. When more importance is attributed to PHES for peak shaving, the electricity generation costs will decrease and the LOLE will tend to rise. When a larger fraction of the PHES is reserved for balancing wind power, this causes the electricity generation costs to increase and the LOLE to decrease. In other words, raising either the peak shaving or balancing fraction of PHES, usually is paired with an opportunity cost of the PHES in terms of electricity generation costs or reliability of the system. The aim should be to attribute more importance to peak shaving when wind power is low and overall demand high and to uphold a higher level of balancing reserves through PHES when demand is low and electricity generation from wind power is high.

The indirect storage of wind energy as heat through heat pumps gives another alternative. As long as the produced heat is valuable, the high SPF of the heat pump can lead to respectable GHG emissions savings on the heating side, even offsetting the lost GHG emissions savings from injecting wind power in the electric grid. This is especially true when the alternative method for heating is through oil-fired boilers. The reduction in the case of gas-fired boilers as reference heating method is less spectacular. Moreover, through the storage of the wind power output, the intermittent behaviour of wind power is completely compensated. However, it has to be stressed that these savings are highly dependent of the efficient technology of the heat pumps with a high SPF. Replacing less efficient boilers with heat pumps explains to a large extent how this exercise can achieve significant savings. Also without explicit use of electricity from wind power, these savings can be achieved, as studied by [92; 205]. The assignation of electricity from wind power for the operation of heat pumps has the added advantage of offering GHG-emissions free electricity and of reducing the variability and relative unpredictability of electricity from wind power injected into the transmission grid.

In reality, a combination of these options can lead to improved results. It can be imagined that heat pumps are used as peak shaving for the energy produced by wind farms. An interesting case can be discerned during winter, when both demand for heat and wind power output are higher. After using the peaks in wind power output for the operation of heat pumps during winter, the remaining, less variable electricity from wind power could be balanced out by pumped hydro storage.

The novelty of the research in this chapter is focussed on two elements. Firstly, the storage of wind-generated electricity in PHES is studied from a dynamical point of view. The balance that needs to be made between the two main functions of PHES adds a new perspective to the research on hydro-based storage of wind power. Usually PHES and wind power are examined in small and isolated systems. The interaction with an entire electricity generation system, as performed in this chapter, is often not examined. Secondly, the exercise of not injecting the electricity from wind power in the transmission grid, but using it locally for the operation of heat pumps, is intended to consider different uses of wind power. Perhaps the application of wind power for the operation of heat pumps and storage of heat are not the most common views on the integration of wind power. However, it can offer some alternative solution for coping with large amounts of wind power. It is good to know that not all wind-generated electricity needs to serve the same purpose and that other useful means can be found for it, still keeping the prime objectives of wind power in mind.

PART 3

Backup of wind power on the long term

7. VALUE OF WIND POWER ON THE LONG TERM

Wind power investments have a certain value. The mere fact that they exist can already serve as a first proof[99]. On the long term, it is possible to investigate whether wind power investments make sense.

Because of its variable nature and wind power capacity factors being considerably lower than conventional generation sources, wind power will not be attributed the same value as these other generation sources. For wind power to be easily integrated in electricity generation systems on the long term, it is important for these systems to be able to cope with the constant fluctuations of wind power. Electricity generation systems should be operated within the set reliability standards after the integration of wind power as well.

This chapter analyses the impact of wind power on the reliability of electricity generation systems using the model covered in section 4.3. The impact of various settings of wind power integration in the IEEE reliability test system is analysed using different adequacy indices. The adequacy indices approach also allows for the determination of the capacity credit of wind power, which can be seen as a value indicator of wind power since it expresses how much wind power can contribute in terms of capacity, compared to the rest of the electricity generation system.

Firstly, the concept of capacity credit of wind power is introduced and applied to the IEEE Reliability test system. Next, the impact of the wind farm siting is investigated. Finally a conclusion is given for the valuation methods of wind power on the long term.

[99] It is clear that wind power investments are usually subsidised. However, these subsidies are not given without any reason. They partly serve as a way to promote cleaner energy, which is a desirable good.

7.1 Capacity credit of wind power

The mere addition of intermittent sources such as wind power to an existing system, while keeping the demand unchanged, almost always brings about a positive impact on the overall reliability of the electricity generation system, just as the addition of any other generation source[100]. However, just adding extra capacity, without any other changes in the system will not always be the case. In practice, because wind turbine capacity expansion is expected to replace part of other expansions of mostly thermal and dispatchable plants[101], it becomes part of the *adequacy* issue. The extent to which intermittent sources contribute to the system adequacy, in a positive or negative sense, however, is usually lower than for conventional power plants. The capacity credit of wind power offers an expression for the determination of this contribution to the adequacy.

7.1.1 Definition of capacity credit

An electricity system has a certain level of reliability. After the introduction of wind power, this reliability should at least remain the same. Only introducing wind power as an additional measure to what was planned, will tend to increase this reliability. As introduced above, mostly however, the investment in wind power will postpone other investments. The extent to which this can occur without loss of reliability is designated by the capacity credit.

The capacity credit is defined by how much installed wind capacity statistically contributes to the guaranteed capacity at peak load [71]. Due to the variability and lower availability of wind, its capacity credit tends to be lower than that of other technologies [25]. The capacity credit expresses the contribution of variable-output wind power to system adequacy. It should be quantified by determining the capacity of conventional plants displaced by wind power or allowed increase in demand, whilst maintaining the same degree of system reliability, with unchanged probability of loss of load in peak periods. An analytical representation of both definitions is given:

[100] At least if appropriate measures for timely balancing on the short term scale are taken.

[101] An expansion could impose itself when demand is rising or when decommissioned power plants need to be replaced.

$$\text{Adequacy}(system) = \text{Adequacy}(system + x_{wind} - y_{conventional}) \tag{7.1}$$

or

$$\text{Adequacy}(system) = \text{Adequacy}(system + x_{wind} + y_{PLCC}) \tag{7.2}$$

where

x: amount of wind power under consideration [MW]

y: capacity credit [MW]; the capacity credit can also be expressed in relation to the amount of installed wind power: y/x.

$y_{conventional}$: amount of conventional power than can be left out.

y_{PLCC}: amount of allowed increase in peak load carrying capability (PLCC).

The capacity credit can be used as a way to compare wind power with conventional power in the system, by implicitly introducing the reliability of the system in the comparison. When a certain investment in wind power is considered, it is helpful to know beforehand what its actual contribution to total system generation capacity will be. Obviously, this contribution will not be the same as that of conventional generation units. Nevertheless, wind power will always have a certain value in terms of contribution to reliable capacity. In practice the capacity credit of wind power expresses how much conventional capacity can be spared in the system or how much demand can rise, while upholding the same reliability level.

The capacity credit of wind power should not be confused with its capacity factor. The capacity credit is related to the capacity factor but will give a better idea on the effectivity of the considered wind power introduction when seen in the entire electricity generation system

The capacity credit is related to the indices quantifying the system adequacy such as the indices LOLE, LOEE, LOLF or EIC introduced in section 4.3. Indeed, the capacity credit is determined by looking at options with and without additional wind power, while maintaining the same level of reliability. This level is expressed by one of the adequacy indices. A smaller capacity credit brings the need for a larger system margin to maintain adequacy.

7.1.2 Calculation methods of capacity credit

There are basically two different ways to calculate the capacity credit of wind power, namely through simulations and through probabilistic analyses.

In **simulation** methods, the secure operation of the system is analysed by means of time-series data using simulation models. The most significant events are special combinations of load and wind speed, especially at moments of high load. Often a sensitivity analysis is performed with the time-series data, shifting the time series of wind power against the load data in steps of hours or days. A possible way of calculating the capacity credit is through taking the adequacy index of the base scenario of an electricity system before wind power introduction as a reference. Then the hourly wind power production is subtracted from the load[102], leaving a reduced load to be covered by the conventional units in the system. The adequacy index is then recalculated. Next, two options exist. Firstly conventional capacity can be removed from the system by iteration until the original reliability level is reached again. The conventional capacity that is being removed in comparison to the base scenario, is called the capacity credit. It is mostly expressed as the ratio of removed conventional capacity to the installed wind power capacity. The second option consists of increasing peak demand in the system until the reference reliability is reached again. The capacity credit is then defined as the amount of increased peak load.

The **probabilistic** method is preferred for system planning purposes. It assesses the availability of each power plant in the electricity generation system. For instance, it is commonly assumed that a coal power plant has a technical availability of about 90-95%. Wind power output is taken into account by introducing both its installed capacity and wind speed profiles into a model. Each wind speed level has a certain probability. Based on the probabilities of individual power plants, wind turbines or wind farms, the probable states of the whole electricity generation system can be determined. The probability to be able cover diverse load levels can calculated by comparing the probabilistic load levels with the probabilistic instantaneous power availability [14].

Often, the capacity credit is calculated by looking at the amount of conventional capacity that a certain amount of wind power can displace while preserving the same level of LOLE [17; 38; 209]. There are two limitations to this approach. On the one hand, the LOLE is just one adequacy index and does not say anything on the extent of a loss-of-load. It is therefore useful to look at other adequacy indices as well. On the other hand, it is not obvious which type of conventional power plant, to be displaced by wind power, should be taken as a reference to compare the wind power with. If an actual evaluation of wind power against an entire system is aimed for, it is not entirely unambiguous to choose only one power plant that wind power can replace. To have a more generic approach, the increased peak load carrying

[102] Wind as negative demand has been covered in section 3.1.1.

capability (PLCC) is looked at in this analysis. The allowed increase in PLCC stands for how much the peak demand can rise after an addition of a certain volume of wind power, while preserving the same reliability level. The allowed increase in PLCC is taken to represent the capacity credit of the installed amount of wind power.

While a formula for the analytical determination of the capacity credit is not generally recognised, attempts have already been made to calculate the capacity credits without directly applying a simulation or probabilistic method[103]. In the literature, many other approaches to capacity credit exist such as the approximation of the capacity credit by the capacity factor during the 30% peak hours in a year, as demonstrated by Milligan and Parsons [210]. Both Soens [117] and Voorspools and D'haeseleer [211] use a regression formula to approach the capacity credit of wind power. Laughton uses an approximation for the British system's capacity credit as presented by Eq. (7.3) [43].

$$CC = \left(GW \text{ of wind capacity installed}\right)^{N} \tag{7.3}$$

where $N = 0.5$ for a central value and $0.43<N<0.6$ with regional variations.

Other methods are described in [17; 212].

7.1.3 Factors influencing capacity credit

Several factors influence the capacity credit value. These are often those that already influence the operational backup of intermittent sources. Now however, they operate on a different timescale.

Firstly, the correlation between intermittent energy sources and peak load, determines to a great extent what the capacity credit of that intermittent source will be. Negative correlation between intermittent energy sources and (peak) load cause the intermittent sources to offer no contribution to peak demand. Photovoltaic cells in cold western countries, for example, cannot provide energy at peak moments, that is during winter evenings, when it is dark. They will therefore have a very low capacity credit. A different story exists in warm countries where peak load is dependent on large air conditioning demands, which often coincides with significant production from photovoltaic cells [17].

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[103] A possible improvement of such an approach is introduced in section 9.4.4.

Apart from correlation of intermittent sources output and load, the correlation between several intermittent sources is of importance. For instance, wind speeds at different wind farm sites might be uncorrelated. This will lead to a better aggregate wind energy provision since the smoothing of wind power across different geographical sites makes it less variable and therefore more reliable. Less backup capacity is needed to cover extreme variations in wind power [38].

Another factor is found in the range of output and total variability of the intermittent energy sources [17]. When wind power, for example, fluctuates only between two extreme output levels, namely 100% and 0% of its capacity, to generate an aggregate value corresponding to a capacity factor of 30%, normally more backup capacity will be needed. At moments of 0% output, wind power does not contribute at all to the system. When a set of interconnected wind power sites always produces continuously at 30% of its capacity, all year round, it can practically be considered as a very reliable conventional power plant and will hardly need any backup.

Related to this last factor, the average level of output of the intermittent source, its capacity factor, will strongly determine the level of the capacity credit [17]. The more energy is delivered on average during a year, the more it may contribute to the system. For wind power, this average output value is related to the average wind speed.

A fifth influence has to do with the penetration level of wind power [14]. The more wind power is introduced in an electricity-generation system, the less the last installed wind turbine will contribute to the capacity, as further demonstrated in section 7.1.5.

An obvious element in the determination of the capacity credit is the desired degree of system reliability. Higher required system reliability levels coincide with lower index values. To get these higher adequacy levels, more investment in backup is needed and the resulting capacity credit will be lower.

A last important factor is the possibility of exchange of energy from intermittent sources through interconnections between different control areas [14]. More exchange possibilities offer more options to manage wind power. Necessary capacity can be found abroad, sometimes at better conditions than what could be done within the same control area. Also, the geographical dispersion effect becomes more interesting when looking at wind power with interconnections. It has to be kept in mind, however, that using transmission capacity for this geographical dispersion restricts the use of this capacity for other means by the market.

7.1.4 Evolution of capacity credit according to the literature

Capacity credit of wind power has been found to behave according to a typical path in relation to the amount of intermittent sources integrated into the system. According to several studies, usually applying the LOLP-based determination of the capacity credit, the capacity credit, relative to the amount of wind power capacity shows a decreasing pattern [17; 25; 213]. The reason has to be found in a system being able to easily cope with a small amount of variation coming from wind power, without the need for new investments. When the volumes of wind power become larger however, the system will need relatively more capacity to cope with the particular behaviour of wind power. Very large amounts of wind power will have a capacity credit close to zero. It has to be remembered, however, that even with the improbable event of capacity credit being zero, wind power still has its use since it will save up primary energy and emissions. Notwithstanding a zero contribution to capacity in the system, wind power will always have some valuable energy contribution.

Most studies find a capacity credit of about 20% for intermittent generation when 10% of the energy is provided by intermittent sources. The range of capacity credit varies between 10% and 35% for 10% of energy foreseen by intermittent sources over a year. Most results to date show capacity credits greater than zero, which proves that wind power indeed does have a capacity credit.

7.1.5 Analysis of capacity credit for the IEEE reliability test system

With the Markov matrix algorithm, an unlimited amount of wind speed data having the same statistical characteristics as the measured meteorological wind speed data can be generated. These wind speed chains serve as input for the Monte Carlo simulations the author has performed. Along with random parameters for power plant or high voltage line failure, a random wind speed profile for an entire year is used as input for the simulation of a year. For that year, the reliability indices LOLE, LOEE, LOLF and EIC are calculated within the IEEE reliability test system.[104] The reference values for LOLE, LOEE, LOLF and EIC are calculated for the system without

[104] Recall that the applied test system, introduced in section 4.3.2.2, has 3405 MW of installed conventional capacity.

any installed wind power and amount to 22 hours/year, 2323 MWh/year, 6 occurrences/year, and 8.04 M€/year, respectively.

For different amounts of installed wind power, ranging from 50 MW to 600 MW and all installed on the same bus number 18, the capacity credit is determined for each adequacy index. The allowed increases in PLCC, rendering the same adequacy level as the reference case without wind power determines this capacity credit. To get a continuous function of rising values for the reliability indices with increasing peak load, a quadratic fit is applied to the values calculated for steps of 10 MW peak load increase. An illustration of the determination of the capacity credit using the LOLE as reference adequacy index and a 100 MW and 400 MW wind farm on bus 18 is given in Figure 42 and Figure 43 respectively. Additional curves are determined for the other adequacy indices and presented in Appendix D.

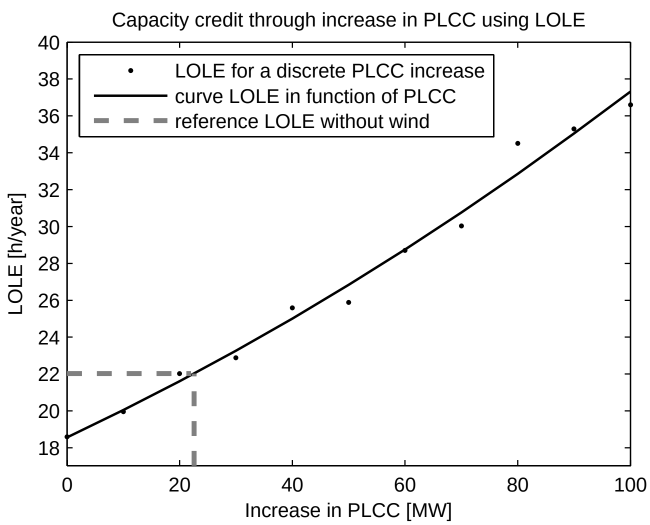

Figure 42: Increase in PLCC and corresponding LOLE with a quadratic fit for 100 MW installed wind power. The reference LOLE for a base case without installed wind power of 22.03 h/year is used as adequacy index.

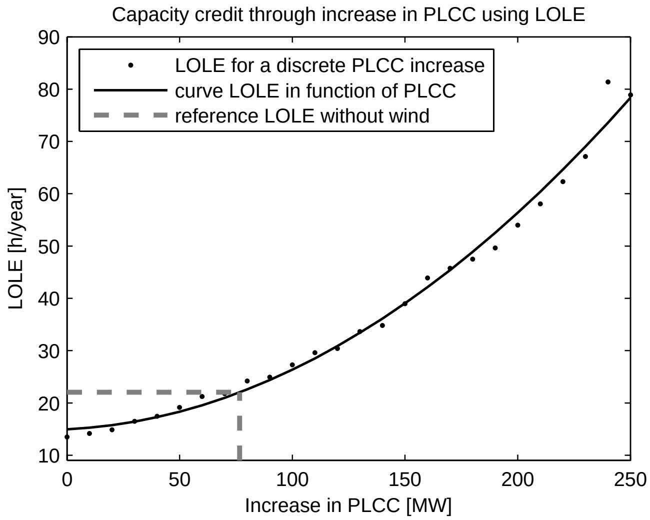

Figure 43: Increase in PLCC and corresponding LOLE with a quadratic fit for 400 MW installed wind power. The reference LOLE for a base case without installed wind power of 22.03 h/year is used as adequacy index.

For small amounts of wind power on the test system, the allowed increase in peak load carrying capability (PLCC) remains by and large the same. This is illustrated in Table 26. The capacity factor of the installed wind power, given in Table 27, is found to be a reasonable approximation of the capacity credit for low levels of installed wind power. Up to 200 MW of installed wind power, the capacity credit values, calculated with the four different adequacy indices, do not differ substantially from the 24% value of the capacity factor. This indicates that the first installed wind turbines hardly have any negative effect on the reliability of the system. The peak demand can be increased in relation to the capacity factor of the wind turbine while preserving the same level of reliability.

Installed wind power [MW]	CC using LOLE		CC using LOEE		CC using LOLF		CC using EIC	
	[MW]	[%]	[MW]	[%]	[MW]	[%]	[MW]	[%]
50	14.0	28.03	10.5	21.03	14.5	28.94	10.1	20.16
100	$\boxed{22.6}$	22.58	17.0	17.01	20.5	20.48	16	15.97
200	45.8	22.90	41.6	20.78	34.2	17.10	39.3	19.67
300	60.9	20.29	57.1	19.02	40.7	13.55	53.0	17.66
400	$\boxed{76.7}$	19.17	72.8	18.19	46.9	11.74	67.2	16.79
500	80.3	16.07	77.2	15.44	48.9	09.79	71.2	14.24
600	83.6	13.93	74.9	12.48	50.4	08.40	67.5	11.24

Table 26: Evolution of the capacity credit on bus 18 of the IEEE Reliability test system, in absolute allowed increase in PLCC and relative to the installed amount of wind power, applying LOLE, LOEE, LOLF and EIC as adequacy indices. The two boxed values correspond to the values determined in Figure 42 and Figure 43.

Some values in Table 26 are found to be outliers. The capacity credit values corresponding to 100 MW of installed wind power are comparably low. This has to do with the dynamic behaviour of the system when integrating wind power. The capacity credit values are determined through fitting a quadratic curve to the calculated adequacy indices for different increases of PLCC. For the calculation of the 50 MW and 100 MW capacity credit, few values determine the shape of this curve, thereby being sensitive to any outlier. The combination of a certain amount of installed wind power, with different levels of allowed PLCC increases, give rise to different maintenance schedules and optimal power flows, which influences the adequacy indices. The LOEE and EIC showing comparatively the highest discrepancies in capacity credit values, refer to a few loss-of-load situations where the shedding of important amounts of energy is the only solution for balancing demand and supply.

Installed wind power [MW]	Electricity from wind [%]	Capacity Factor [%]
50	0.59	24.28
100	1.17	24.24
200	2.31	24.28
300	3.41	24.30
400	4.48	24.25
500	5.62	24.34
600	6.74	24.33

Table 27: Electricity generation from wind and capacity factor for installed wind power on bus 18 from 50 to 600 MW.

For increasing amounts of wind power, the capacity credit, expressed in percentage of installed wind power, decreases for each of the applied adequacy indices. Previous studies reveal the same downward trend for capacity credit with increasing wind power. They are usually based on the comparison made using the LOLE index [14; 17; 18; 43; 213].

The capacity credit calculation with different adequacy indices allows for a deeper analysis, with the four indices behaving differently under increasing wind power. The LOLF and EIC indices suffer most from larger amounts of wind power on the system. This indicates that for the same amount of loss-of-load expressed in hours or in energy, loss-of-load events occur more frequently when large amounts of wind power are installed. These events also generate relatively higher costs to the system.

The analysis also shows the logical result of wind outperforming the more expensive generating units in the system first. An overall reduction of fuel costs is found to take place for increasing amounts of wind power as well. Another element of observation is the evolution of the adequacy indices over the different busses. Since bus 18, where the wind power is installed, is well connected to the rest of the system, the reductions in LOLE, LOEE, LOLF and EIC through the addition of wind power are evenly spread over all the busses in the system. The local addition of wind power impacts the local adequacy indices to the same extent for the entire system. Moreover, the frequency of the causes for loss-of-load events is found to remain the same. Overall deficits of generation power, losses of a connection to the high voltage grid or overloads that cannot be overcome by rearrangement of generation capacity are all reduced to the same extent with the addition of wind power, according to their contribution to loss-of-load events.

7.2 Impact of location of wind power investments in the grid on reliability

One of the possible parameters that might influence the reliability of the electricity generation system with the integration of wind power is the location of the wind farm in this system. Normally, the addition of generation capacity to the system has a positive influence on the adequacy. This is also true when adding wind power. The extent of this influence depends on the location of the additional power.

Several analyses have been performed to investigate the adequacy impact of wind farm location in the system. Additions of 100 MW and 200 MW of wind turbines on the buses 1, 7, 13 and 18 have been examined. The adequacy indices for the 100 MW wind power addition, as given in Figure 44, have been calculated for an unchanged demand profile on the one hand and for a demand profile with an increase of peak demand by 100 MW on the other hand. Results for the four different adequacy indices with 200 MW wind power addition and peak demand level increases of 0, 100 and 200 MW are represented in Figure 45.

The impact of introducing wind power on different busses is not very large. The IEEE system is composed in a way that it allows a good power flow under various circumstances. The positive impact of wind power on the system remains essentially the same for any of the wind farm locations. The most positive impact of both 100 MW and 200 MW wind power introduction in the system with unchanged reference demand occurs when locating the wind power on bus 1. On that location, corresponding to a relatively weak grid connection, these levels of wind power lead to the best result in terms of adequacy improvement. Logically, the largest reduction in the adequacy indicators is achieved for the 200 MW wind power introduction.

The situation changes for increasing levels of peak demand, as illustrated in Figure 45, indicating the dynamic behaviour of the system in coping with different demand levels. For changes in demand, the electricity delivery and ensuing power flows are modified.

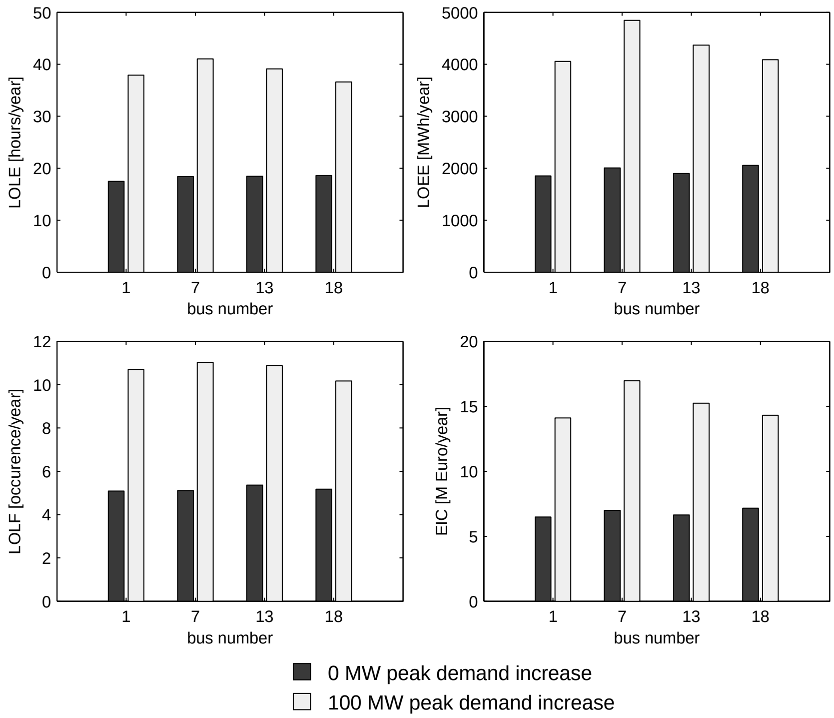

Figure 44: Four adequacy indices for the addition of 100 MW wind power on different busses. For 0 MW (dark) and 100 MW (light) peak demand increase.

To get more insight in the influence of the grid connection on wind power introduction, the determination of the adequacy indices for a 100 MW wind farm on bus 1 is repeated for a situation with reduced transmission capacity on the line between bus 1 and bus 2. By creating a weaker transmission line, bus 1 becomes less connected to the rest of the system. The resulting change in adequacy remains limited.

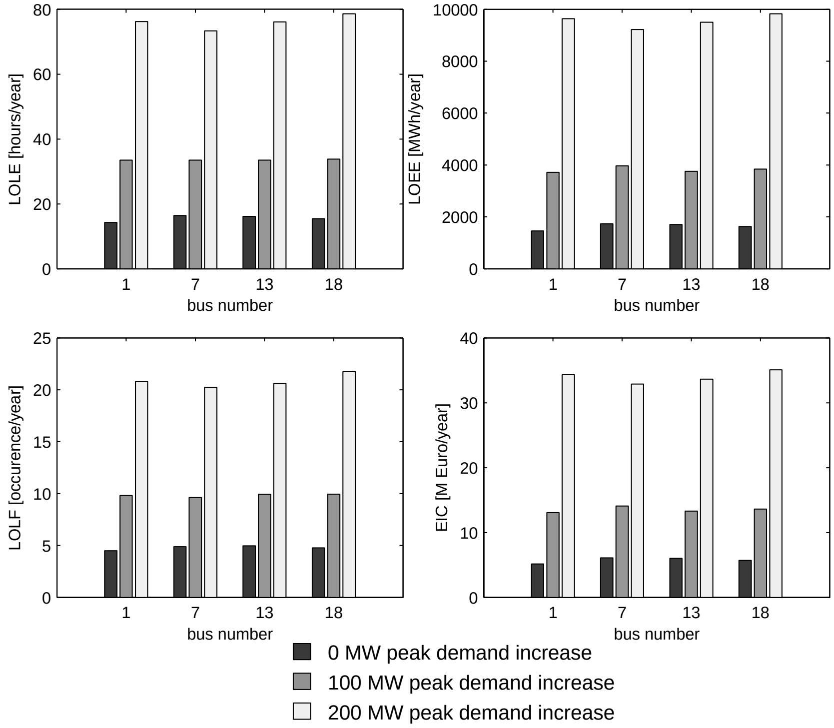

Figure 45: Four adequacy indices for the addition of 200 MW wind power on different busses. For 0, 100 and 200 MW peak demand increase respectively.

When looking at a situation with 100 MW wind power that is installed on bus 1, with a rise in PLCC of 100 MW, as depicted in Figure 46, the four adequacy indices rise due to the reduction in transmission capacity to and from bus 1.

The reduction of adequacy can be analysed more closely by looking at the origins of loss-of-load events, as illustrated in Figure 47. The most important increase in causes for loss-of-load events occurs in the overloads that cannot be overcome by rearrangement of generation capacity. This is logical since no change is made that could cause increased deficit of generation power or the loss of a connection to the grid.

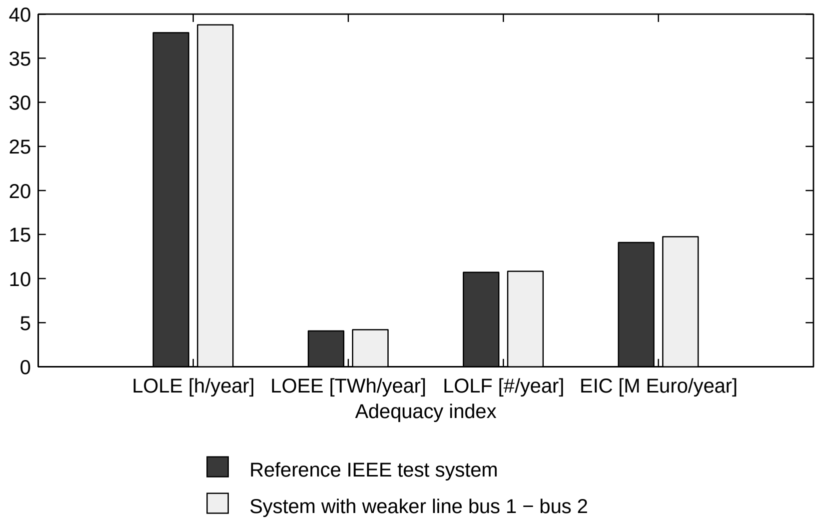

Figure 46: The adequacy indices for the regular IEEE test system and the same system with a considerable decrease in connection capacity on the line between bus 1 and 2.

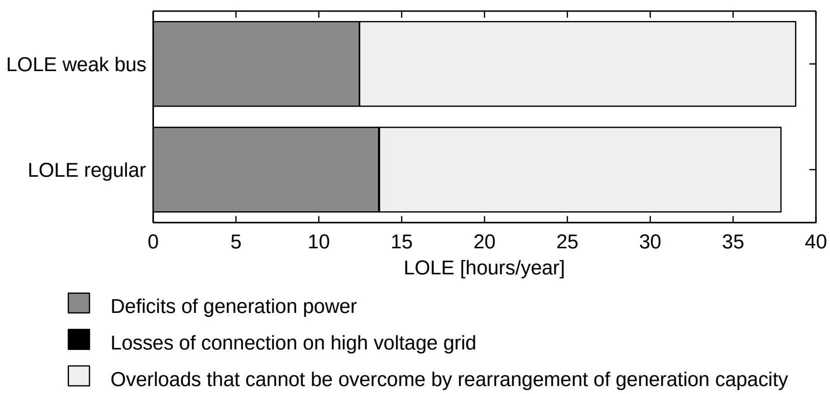

Figure 47: Origin of loss-of-load events for the regular IEEE test system and the same system with a considerable decrease in connection capacity on the line between bus 1 and 2.

With the reduced transmission capacity between busses 1 and 2, the largest impact of adequacy reduction can be observed for bus 2. Since the wind power is located in bus 1, it will contribute to the adequacy of the bus. The negative impact of having a worse connection to the rest of the system is compensated by the additional generation capacity in the bus. Bus 2 on the other hand also suffers from a decrease in transmission capacity from and to the bus, which is not made up for by additional capacity, thereby suffering from an increased number of loss-of-load events.

7.3 Conclusion of the contribution of wind power to the system on the long term

The reliability of an electricity generation system is affected by the addition of wind power. To give a certain value to wind power investments, the capacity credit can be used in adequacy analyses. The capacity credit determines the value of a certain capacity of wind power as it expresses how much the wind power contributes to the adequacy of the system. The allowed increase in peak load carrying capability (PLCC) that leads to the same reliability level as before the addition of wind power in the system, is taken to represent the capacity credit.

To calculate the capacity credit, a model simulating the hourly electricity generation system operation is used. The "IEEE Reliability Test System – 1996", with detailed data on both generating units and transmission grid is used to perform several adequacy analyses with wind power addition. The main drivers of the adequacy of the system are the random outage events and fluctuating wind speed profiles. To represent variable wind speed, Markov matrices are applied for the generation of the desired amounts of random wind speed profiles for a whole year, featuring the same statistical properties as original wind speed data. A sequential Monte Carlo approach simulates numerous years to generate a consistent outcome for the adequacy analysis.

The determination of the adequacy is accomplished through four different indices, namely Loss-of-load expectancy (LOLE), Loss-of-energy expectancy (LOEE), Loss-of-load frequency (LOLF) and the expected interruption cost (EIC). Using these indices to determine the allowed increase in PLCC, the capacity credit is calculated for growing amounts of wind power. The capacity credit is found to decrease with increasing installed wind power. The steepest decline in capacity credit occurs when using the LOLF or EIC as adequacy index. The distribution of loss-of-load events over the different busses and the frequency of causes for loss-of-load events are found to remain the same for changing levels of wind power.

The impact of the location of wind power introduction on the adequacy indices is relatively small. Some advantage is obtained from installing wind turbines on specific busses. Not every location renders the same result in adequacy improvement. It is also important to take into account how much transmission capacity is available for the busses where a certain amount of wind power is installed.

The innovative element of this chapter is not so much the delivery of new notions or methods, as the combination of existing principles for a complete capacity contribution analysis of wind power. The concept of capacity credit, used to quantify the capacity contribution, is defined and one of the common definitions is used as the basis for the calculation method in this chapter. Capacity credit in this chapter is defined as the allowed increase in peak demand, after the addition of wind power in the system, to reach the original reliability level. This definition makes most sense, as it does not depend on any specific power plant in the system that is taken to be outperformed by wind power, which constitutes the basis of an alternative definition of capacity credit. Other elements that differentiate the approach in this chapter is the use of different adequacy indices that determine the reliability level. The calculation of the indices through Monte Carlo simulation combined with the use of Markov matrices for an unlimited number of wind speed profiles as input, offers additional novelty compared to the regular calculation of adequacy indices. Finally, the curve fitting on the calculated adequacy indices to get a continuous range of increase in peak demand, presents a more precise determination of the capacity credit, without having to calculate the adequacy indices for every possible increase in demand, thus saving on calculation time.

8. IMPACT OF THE SYSTEM COMPOSITION ON THE INTRODUCTION OF WIND POWER[105]

Wind power is becoming a widespread electricity generation technology. Its fuel free and zero emissions aspects make it a popular investment in electricity generation systems. Once built, wind turbines, considered individually, can generate electricity at an almost zero cost. This point of view does however not hold when looking at the integration of larger amounts of wind power into the electricity generation system. Because of the specific character of wind, being a variable and relatively unpredictable energy source, the integration of wind power into a system brings about additional challenges for the operation and development of the system. These challenges depend to a great extent on the specificities of the country and its power system under consideration. The aim of the research presented in this chapter is to get a first general insight into the impact of system design on the introduction of wind power. Lund [214], for example, also discusses different power systems but his focus remains on the specific presence of combined heat and power (CHP) power plants in the system. The All-Island grid study [215; 216] and Doherty et al [217] approach the generation portfolio as one that needs to be optimised for the inclusion of wind power in the future. Söder and Holttinen [218] concentrate on the different possible methodologies in wind power integration studies.

In what follows, the effect of the composition and behaviour of the electricity generation system on the integration of wind power are examined. New operational requirements and reserve needs for the wind power introduction emerge and with it, additional costs for the system arise. Numerous wind power integration studies have already been performed, all showing a wide range of resulting costs [17; 18; 33; 95; 96; 130; 132; 219; 220]. However, not only the applied methodology lies at the basis of diverging outcomes of these studies. The inherent differences in the considered systems greatly influence the outcomes as well. To overcome this and to examine the generation mix in a country-independent way, in this chapter, several distinct generation mixes are being considered, using a Mixed Integer Linear Programming (MILP) model to simulate these differences.

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[105] This chapter is based on the accepted article "Luickx, P.J., Delarue, E.D., D'haeseleer, W.D. 2008. Effect of the Generation Mix on Wind Power Introduction. Accepted for publication in IET Renewable Power Generation, December 2008."

The approach adopted in this chapter is to compare the impact of electricity from wind power in three electricity generation systems that only differ in their composition.[106]

This chapter digs deeper into the system composition characteristics of wind power. After first looking into the different types of power plants offering capacity backup, and the alternatives to using backup, an analysis is made of three differing electricity generation compositions and its impact on wind power integration. They are evaluated in the light of both wind power variability and unpredictability.

8.1 Backup capacity providing power plants

The provision of backup capacity[107] can, in broad terms be divided into two options, namely the construction of one or more new power plants, or the retention of older power plants that would otherwise have been decommissioned.

Firstly, there is the choice of building a new plant to provide the necessary backup. It can be chosen and dimensioned so as to provide optimal backup capacity services. This option will be more interesting if the system has to be expanded and the additional intermittent energy sources are foreseen to partly cover an increase in demand. The existing capacity has to be retained and the intermittent generator, together with its backup, will be added to the system. Of course, the new backup plant can provide more services than only backup capacity. If run optimally, it will probably be used to provide backup for the system as a whole and perhaps also offer supporting services. An efficient combined cycle gas turbine, storage plant or other type of plant can be built to provide this backup capacity for intermittent sources.

The second option is to utilise existing power plants as backup capacity. This situation will mostly occur when intermittent sources are added to the system with no actual need for more provision of electricity. The advantage about using existing power plants is that no new investments are needed. However, there is still a cost to keep the plants operational. There are also some disadvantages of using existing power plants. Firstly, if these plants were truly economical, they would operate for more than just reserve, unless the reserve pricing is very high. Secondly, old plants

[106] An alternative way of investigating the system composition impact of wind power in a more dynamic way would have been to develop an investment model for an electricity generation system and examine which parameters are determinant for the final outcome of the system composition. This is introduced in section 9.4.10.

[107] The concept of backup capacity was previously discussed in 4.1.3.

are often less reliable exactly because of their age. Furthermore, older existing power plants are often more polluting, thereby countering one of the main purposes of installing extra wind energy. Finally, older power plants are not always starting up fast, which might make them inappropriate as backup capacity.

In this chapter's analyses mainly gas-fired combined cycle, coal-fired and smaller gas and diesel units are investigated as plants offering backup capacity.

8.2 Alternatives to backup capacity

Alternatives to backup capacity also exist. There are ways to reduce the need for actual power plants delivering backup capacity. However, these alternatives are best seen as variants on the backup capacity needs.

First of all, connections with other control areas might be an option. Effectively enlarging the control area, improves the efficiency of backup provision. More players usually lead to more efficient pricing. Instead of looking for backup capacity in ones own control area, it might be more interesting to look for it abroad. A requirement for this, however, is to increase the interconnection capacity between control areas. The cost for this has to be weighted against the cost of providing backup capacity within the own control area. Increasing interconnection also has other benefits than solely for backup capacity purposes.

Storage, which was already discussed in Chapter 7, might also be an option. The storage such as PHES or heat pumps can act as backup providers when wind power output is failing, releasing the energy previously stored during higher levels of wind power output. This way, the power provided by intermittent sources becomes of higher value. This option obviously has some drawbacks as well. The cost of connecting the storage, usually situated in locations that contain some difference in height, with the wind power production, often close to coast-lines, is to be accounted for as well.

Finally demand response might also offer a solution. When the possibility exists to shift demand in time, using price incentives, moments of low generating capacity, for example when a general windstill takes place, can be compensated by a temporary decrease in demand, until the generation capacity becomes easily available again.

8.3 Three electricity generation systems with different composition

The applied methodology is based on the MILP approach explained in chapter 4. Three compositions of an imaginary electricity generation system are considered as case studies. The size of the system, expressed as installed power (in MW) remains constant with the generation mix constituting the only variable in this system. The compositions have been chosen to represent different types of systems and are given in Table 28. In the first system, the "gas" system, the majority of the power plants are gas-fired. The installed power of gas-fuelled power plants such as classic gas-fired with a rankine cycle and combined cycle (CC) power plants almost makes up 70% of the total system. The second system, referred to as "coal", mainly relies on coal, with the coal-fired plants making up 65% of the total power in the system. The "flexible" system is mainly composed of smaller-scale and gas-fired power plants that more easily adjust to changes in demand or supply. This mix of plants allows for a more flexible operation of the system. Each of these systems is confronted with the integration of varying amounts of wind power. Each system behaves differently according to the available power plants and the technical parameters of the power plants such as minimum up and down time, ramp rates and fuel usage.[108]

	GAS	COAL	FLEXIBLE
Nuclear	1000	1000	1000
Coal	3000	11050	3000
Gas	1500	450	300
Combined Cycle	10000	3000	10000
Gas Turbine	100	100	1300
Diesel	200	200	200
Turbo Jet	200	200	200
TOTAL	**16000**	**16000**	**16000**

Table 28: Composition of the three electricity generation systems with different generation mixes The numbers refer to amount of installed power (in MW).

In a regular operation of the mentioned electricity generation systems, nuclear power plants operate in baseload. With the chosen fuel prices, based on the International Energy Agency (IEA) World Outlook prices of 2005 [112] and in the

[108] PHES is not included in the analyses since it influences which power plant becomes the marginal power plant, as explained below. To investigate the exact impact of the conventional power plants, without the interference of peak shaving, PHES is left out of the electricity generation systems, as presented in Table 28.

absence of a CO_2 tax or levy, coal power plants come second after these nuclear plants in terms of fuel costs[109]. Gas-fired power plants, especially the efficient combined cycle power plants, are also used extensively due to their flexible operating characteristics. These can easily adjust to changes in supply and demand. Smaller plants such as gas turbines and diesel motors are used for temporal needs, mostly to cover short-term peaks in demand. They offer more flexibility to the system.

Apart from varying systems, other variables are examined as well to observe their combined effects on wind power integration. As in earlier chapters, the four typical demand and wind speed profiles are used to conduct the analyses. Increasing amounts of wind power are considered as well to investigate the effect of total wind power capacity on the system. The amount of installed capacity of wind power in the three abovementioned systems varies from 0 to 2000 MW.

8.4 Analysis of three different system compositions and its impact on wind power integration

The effectiveness of the integration of wind power into an electricity generation system can be measured in several ways. Two obvious criteria are the fuel cost decrease and greenhouse gas (GHG) emissions reductions. Energy generated through wind turbines can be seen as a way to save fuel. Once a wind turbine is installed, its operation is at almost zero cost and using it whenever possible leads to fuel cost savings. Moreover, for every kWh of energy generated by wind power, a certain amount of GHG that otherwise would have been emitted through fossil fuel burning, is avoided. Both the operational cost[110] and GHG emissions savings are discussed in the light of the composition of the power system in this section.

8.4.1 Fuel cost difference due to variability of wind power

The operational cost savings that can be obtained by wind power are not to be underestimated. Looking at total installed wind power ranging from 0 to 2000 MW, the cost reduction potential can be up to 25% of the operational cost, depending on

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[109] The used IEA prices mention a crude oil price around 36 $/barrel, where it has risen to above 100 $/barrel in 2008. However, as also mentioned in section 4.2.1, the actual prices are of less importance than the ratio between them. The focus is not so much on the overall fuel cost than on the effects of the use of different fuels.

[110] In this section, operational cost is taken to be equal to the fuel and startup costs. Other variable costs are ignored.

the overall wind power output and its variability. The relative cost reduction, expressed in percentage of savings compared to the reference case with no installed wind power, depends on various parameters. The full range of absolute cost reductions for the 2000 MW installed wind power compared to the situations without any installed capacity is given in Table 29. The impact of 2000 MW of wind power in terms of percentage of generated energy is shown in Table 30. In the following the illustrations will be made to a large extent with the wind profile of *Windday C* and the demand profiles of *Day 1* and *Day 4*. When not stated otherwise, the other combinations show comparable results.[111]

		DAY			
WINDDAY	SYSTEM	1	2	3	4
A	GAS	94,169	93,118	91,234	90,460
	COAL	75,222	64,818	66,386	57,108
	FLEXIBLE	90,604	92,231	92,403	92,029
B	GAS	589,232	582,918	588,023	576,399
	COAL	461,426	394,596	391,711	366,811
	FLEXIBLE	585,593	583,130	589,188	580,920
C	GAS	1,078,443	1,075,916	1,073,634	1,067,748
	COAL	839,624	731,859	709,407	696,687
	FLEXIBLE	1,073,526	1,072,222	1,074,642	1,072,243
D	GAS	451,971	449,856	448,677	445,664
	COAL	367,616	318,336	302,080	291,096
	FLEXIBLE	445,946	446,996	448,540	449,618

Table 29:Absolute operational cost reduction (in €) of 2000 MW of installed wind power capacity compared to the cases without wind power. The results are given for wind speed profiles Windday A-D, demand profiles Day 1-4 and system designs gas, coal and flexible.

	DAY 1	DAY 2	DAY 3	DAY 4
WINDDAY A	1.4%	1.5%	1.6%	1.9%
WINDDAY B	8.7%	9.6%	10.5%	12.4%
WINDDAY C	15.7%	17.4%	19.1%	22.4%
WINDDAY D	6.6%	7.3%	8.0%	9.4%

Table 30: Share of wind energy in the total amount of generated energy for wind speed profiles Windday A-D and demand profiles Day 1-4 with 2000 MW of installed wind power capacity.

[111] The demand and wind speed profiles are introduced in section 4.2.5 and can be consulted on the last page of the thesis for easy reference.

8.4.1.1 Impact of the system design

With the introduction of wind power into each of the considered systems, the operational cost of the system decreases. Every kWh of electricity generated with the wind turbines, stands for a fuel saving in the conventional power plants. The cost saving develops differently for each of the three electricity generation systems.

Most significant relative cost reductions occur with high values of wind power integration and high overall wind speeds, combined with gas-based electricity generation systems and low overall demand. Figure 48 depicts the evolution of relative cost savings due to wind power integration into an electricity generation system for high average wind speeds, leading to high wind turbine output. The part relating to *Day 1*, corresponding to a high overall demand, shows that most significant relative cost savings occur with the *coal* system. Installing 2000 MW in this system and assuming a relatively windy day leads to operation cost reductions of almost 20%. The image is different for lower overall demand. For *Day 4*, most significant cost reduction is achieved for the *gas* and *flexible* scenarios, showing a higher relative cost benefit from the introduction of wind power. The *coal* system now has the least interesting cost reduction.

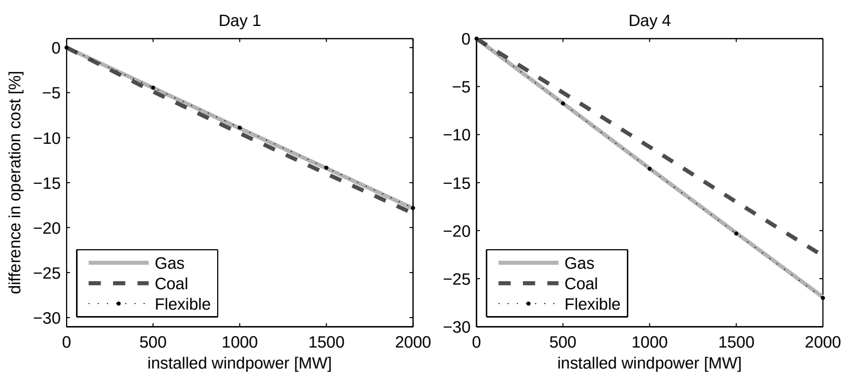

Figure 48: Relative cost difference between the base case without wind power and cases with increasing amounts of wind power. Wind profile of windday C applied to the load profiles of day 1 and day 4.

Although the *gas* and *flexible* systems have a different composition, they behave alike to a very high extent, indicating the activation of the same power plants at the same times. Both these flexible systems allow for a good integration of wind power.

The system can readily adjust to varying installed wind power for different levels of demand and does not need to rely on peak-load units. Due to the higher overall operation cost of gas-based electricity generation systems, the cost reductions obtained through the integration of wind power are logically more significant for these systems. Looking from an operational cost perspective, systems operating on expensive fuels benefit most from the introduction of wind power.

8.4.1.2 Impact of the demand profile

As can be observed from Figure 49 and Table 29, the *gas* and *flexible* systems offer the same absolute fuel cost reduction for every of the four considered load curves. The less flexible a system becomes, the more a decreasing overall load profile limits the benefits of cost reduction through wind power. The *coal* system has more problems to cope with produced wind energy when loads are decreasing. This is also apparent when observing the cost savings in Euros per MWh of generated wind energy. These are clearly the highest for the *gas* and *flexible* systems. In the considered cases, the savings fluctuate around 23 €/MWh. This cost saving per MWh remains constant over the considered load profiles for the *gas* and *flexible* systems but decreases with declining load profiles for the *coal* system. The coal-based system demonstrates fuel cost savings around 18 €/MWh for the high load profile, decreasing to 15 €/MWh for the lowest overall load profile.

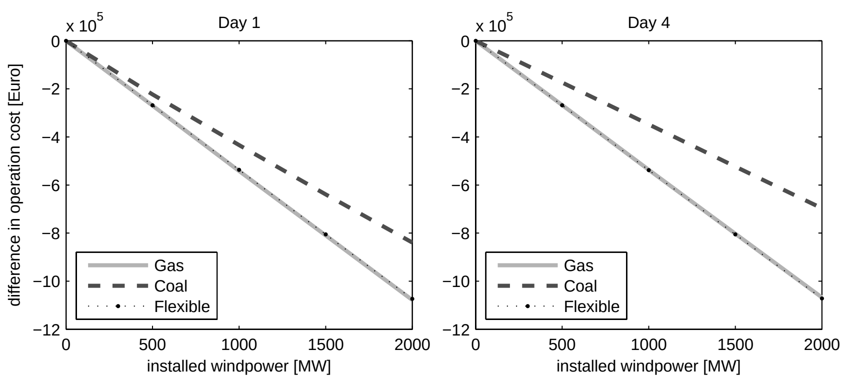

Figure 49: Absolute cost difference between the base case without wind power and cases with increasing amounts of wind power. Wind profile of windday C applied to the load profiles of day 1 and day 4.

The reason is twofold. The first one has to be found with the marginal power plant. This refers to the power plant that covers the last kWh of demand. This is typically the most expensive power plant[112]. When wind power is introduced, the marginal power plant is the first power plant to disappear in the merit order [221; 222]. This shift in marginal power plant is represented in Figure 51 which respectively shows hour 17 without wind power and one with 2000 MW of wind power applying *windday C*. Wind power replaces the most expensive power plants first. In the case of high overall demand, for the *coal* system, a gas-fired combined cycle power plant defines the marginal power plant. Wind power introduction makes (part of) this combined cycle power plant obsolete for the high demand levels. The cost saving of wind power is therefore defined by this combined cycle power plant. In the case of low overall demand, the marginal power plant is a coal-fired power plant, which stands for lower fuel cost and therefore relatively less important cost benefits when outperformed by wind power. Figure 50 depicts the activated power plants during all the hours of the day for the same case as in Figure 51.

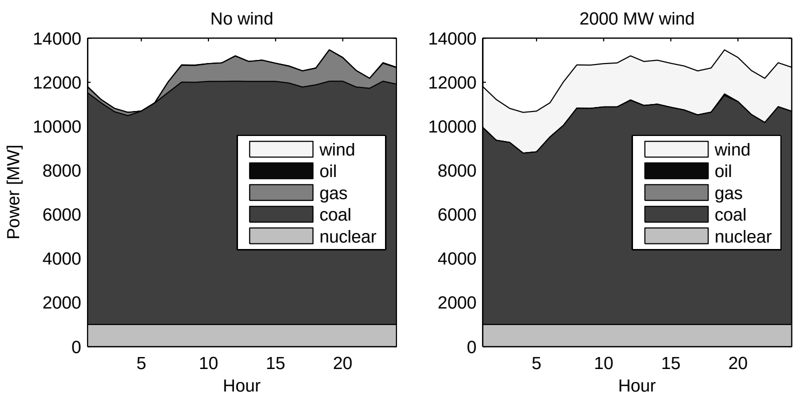

Figure 50: Both figures represent the hourly activated power of the coal system for the demand profile of day 1. The left figure shows the production without any installed wind power; the right one shows the output with an additional 2000 MW of wind power, applying the wind profile of windday C, in the system.

[112] This is assuming that the cheapest options for electricity generation are used first and the most expensive ones come in the end of the merit order.

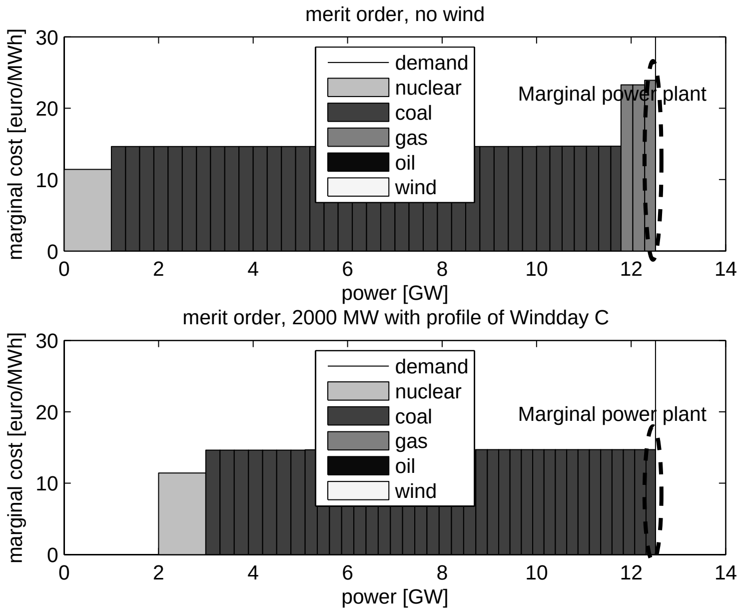

Figure 51: Merit order of two cases for the coal system using hour 17 of Day 1, first without wind power output and secondly with 2000MW wind power under windday C, operational at full power. The marginal power plants are marked.

The second reason is to be found in the higher flexibility of the *gas* and *flexible* systems. With lower loads, fewer power plants are active to cope with the variability of wind power. The *coal* system is less suited to face the fluctuations due to wind power. Typically, it can be said that power plants with more expensive fuels, such as diesel motors or gas turbines, have the advantage of operating more flexibly. They can be switched on and off more frequently and at lower costs or can operate at partial load without large efficiency losses than, for example, coal power plants. Relatively more units are needed in the *coal* system to deal with the fluctuations than in the *gas* system.

8.4.1.3 Impact of the wind speed profiles and the amount of installed wind power

Regular wind power profiles

The higher the overall wind-generated electricity, the more impact wind power will have. This electricity generation is dependent of both the wind speed profile and the amount of installed wind power. The more electricity is generated through wind, the more fuel can be saved. Logically for the same amount of investment, higher wind speed profiles with corresponding higher wind power output are preferred.

As seen in Figure 49, the *coal* system shows a sub-linear fuel cost saving trend with increasing amounts of wind power due to the effect of the marginal power plant, as already explained in section 8.4.1.2. In a first instance, the wind power outperforms a combined cycle gas-fired power plant. The dent in the cost savings curve depends on both the amount of installed wind power and the wind power profile. The latter defines the capacity factor (CF) of the wind turbine. Usually this CF is calculated for an entire year but in the performed simulations, the CFs of the four wind power profiles are calculated for one day. The higher the CF, the sooner will the dent occur in the fuel cost savings curve. For *windday C*, with a high CF of 97%, the decrease becomes less important at around 500 MW, whereas it occurs at around 1500 MW for *windday D*, showing a CF of 40%. The marginal combined cycle power plant is already entirely replaced by a 500 MW wind park with a CF of almost 100%. From higher amounts of installed wind power on, the fuel cost saving will occur with the relatively cheaper coal-fired power plants. With a lower CF, a higher wind power capacity is needed to completely outperform the combined cycle power plant. The *flexible* and *gas* systems have a linear cost decrease function since, for any amount of wind energy produced, gas-fired power plants are the first ones to be outperformed. The shape of the fuel cost savings curve is very much dependent on the relation between the different fuel prices. This is further discussed in 8.4.3.2, which takes into account a CO_2-price.

Extreme wind power profiles: flat and fluctuating profiles

For a more thorough analysis of the variability of wind power, in addition to the previous section where the CF rather than the variability is analysed, a theoretical approach where two extreme wind profiles are considered is applied. In a first fictitious wind speed profile, referred to as the flat profile, a constant wind speed equivalent to 50% of the installed wind power capacity is used. A second wind speed profile shows a fluctuating pattern, making the wind power output switch each hour between full and zero capacity of the wind power. This profile is referred to as the *1/0* wind power profile. Both profiles have a CF of 50%.

Both wind speed profiles have a different effect on the fuel and startup cost reduction. This can be seen in Figure 52, where the cost savings differences between the *flat* and *1/0* profiles are marked. A first observation shows that the *flat* wind speed profile has more cost savings potential than the *1/0* profile. Less optimal usage of power plants with coinciding augmenting fuel costs and, to a lesser extent, additional startup costs explain the difference. This is true for any of the observed demand profiles and increasingly so with rising amounts of installed wind power. The main reason is that the *flat* profile can be considered as an overall equal decrease in demand without creating any additional variability in the system. The *1/0* profile on the other hand adds a large variation on the demand, which the system has to cope with. For this, the system flexibility has to be used to balance the recurring hourly variations.

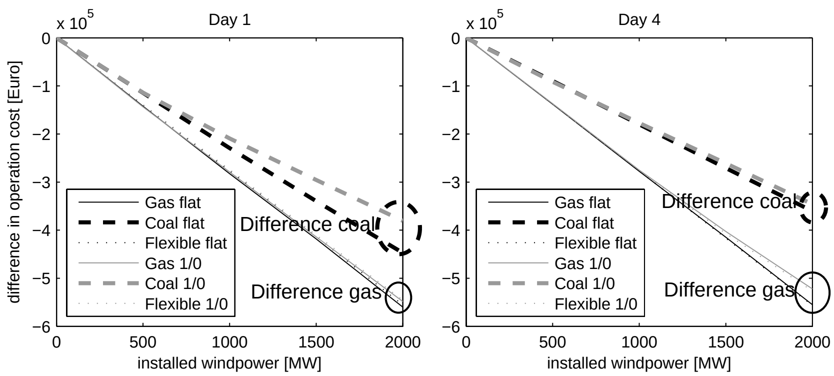

Figure 52: Difference in operational cost savings between a flat wind power profile at 50% of its installed capacity and a fluctuating profile between 100% and 0% of its capacity, for the three different system designs. Demand profiles Day 1 and Day 4 are compared.

Applying the fluctuating wind power profile to the gas system, leads to decreasing absolute fuel cost saving when comparing demand profiles *Day 1* and *Day 2* on the one hand with *Day 3* and *Day 4* on the other. This difference is not related to the absolute level of demand but rather to the actual shape of the profiles of the different days.

Difference in cost reduction for gas scenarios

In a first instance, the cost reduction potential with the *gas* generation mix is analysed by comparing the full lines in Figure 52. Looking at the shape of the demand curves of the demand profiles of *Day 3* and *Day 4,* two factors are found to lead to the fluctuating *1/0* wind power profile generating larger inefficiencies for these demand profiles[113].

On the one hand, a large difference between demand in the morning and at noon or in the evening[114], when demand is peaking, leads to many power plants running at their minimal operation point every two hours in the morning for the *1/0* profile[115]. The combination of peak demand in the afternoon with no wind power (a "0" in wind power provision) output leads to the need for many power plants to be operational at full capacity. The contrast with low demand during the morning, combined with full wind power capacity is considerable. The need for gas-fired capacity is severely reduced in the morning lows when wind power is fully available (a "1" in wind power provision). However, rather than switching off these power plants at these moments, it is more cost-efficient to keep them running at their minimal operation point, coinciding with lower fuel usage efficiencies. The problem does not occur with the *flat* profile since wind power output is constant and fewer extreme cases of gas-fired power plants usage occur.

On the other hand, a longer morning regime, referring to a longer time span of low demand will, in combination with the *1/0* regime, lead to more inefficiency during the day for the same reasons. The first factor is predominating for the fluctuating wind power profile applied to *Day 3*. The second factor can be witnessed for *Day 4*.

The demand profiles of *Day 1* and *Day 2* are such that no large difference between morning and afternoon demand is noted. Therefore, the differences in cost reduction between the *1/0* and *flat* profiles remain modest.

The inefficiencies will become even larger for more significant differences between demand levels during a day. Demand profiles that heavily peak during certain hours of the day and that fall back to low levels at other points of time, will lead to

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[113] *Day 3* is not depicted but shows relatively the same cost reduction evolution as *Day 4*.

[114] The morning roughly refers to hours 0 to 7; the evening usually has its peak demand around 18h.

[115] The demand during the morning is considerably lower than in the afternoon. When the wind speed is at its maximum during the morning, corresponding with a "1" in the wind profile, other power plants have to be operated at low partial loads. They cannot be switched off however, since they are still needed in the afternoon, when demand is high.

increasingly inefficient operation of the available gas-fired combined cycle power plants. This effect can be dealt with through the use of pumped hydro storage, which can store electricity by pumping up water at moments of low demand and releasing it, while driving turbines, at demand peaks. Pumped hydro storage allows to peak-shave demand profiles.

Difference in cost reduction for coal scenarios

Looking at the *coal* scenarios, represented by the dashed lines in Figure 52, the overall cost savings potential is higher for *day 1* than for *day 4*, in the two considered wind speed profile cases, for reasons explained in 8.4.1.2. *Day 1* still relies on gas-fired combined cycle power plants to provide peak power and to balance the fluctuations in demand and wind power output. For the *flat* wind speed profile, there is no need for additional balancing measures since no variability is added to the system. The cheaper coal power plants are used to their full extent. For the *1/0* case however, the extreme fluctuations cause the system to rely more on the combined cycle power plants under operation. Since the coal power plants do not offer the same extent of flexibility, the usage of the gas-fired combined cycle plants is doubled when compared to the *flat* profile. The flexibility of the gas-fired plants combined with these combined cycle plants being already operational due to the high demand, is used to manage the added variability in the system to the detriment of the usually cheaper coal-fired plants. Therefore, the difference in cost savings for *day 1* is significantly larger for the *flat* than for the *1/0* profile. For *day 4*, the demand is low enough to cover electricity demand exclusively with coal-fired power plants. Managing the additional variability of the *1/0* profile is achieved by operating the coal power plants more inefficiently, which is still cheaper than activating a gas-fired power plant solely for this purpose.

Apart from the fuel and startup costs, other elements that are not covered in this analysis come into play when comparing the addition of smooth or very fluctuating wind power profiles in an electricity generation system. The mere fact of repeatedly switching between on and off states of power plants not only leads to efficiency losses, but also to quicker wearing down of elements in the power plants. This has an impact on the investment and replacement costs in power plants [223].

Extreme wind power profiles: wind peaks correlated with demand

Another interesting exercise is to analyse the effect of correlation between demand and wind speed profiles. For this purpose two imaginary wind speed profiles, respectively corresponding to "+1" and "-1" correlation with the four different demand profiles *Day 1* to *4*, are created, as presented in Figure 53. Both wind speed profiles lead to the same levels of generated energy. For the "+1" correlation case, the demand peaks of the demand profiles correspond to a wind power output equivalent to its installed capacity, whereas the demand low matches up with a low in wind power generation. The inverse is true for the "-1" correlation. The cost reductions of the combinations of *Day 1* and *Day 4* with their respective wind power profiles that are perfectly positively or negatively correlated are represented in Figure 54. [116]

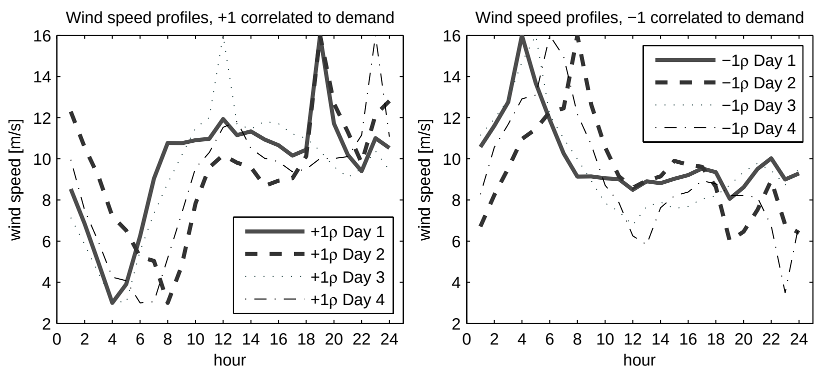

Figure 53: Wind speed profiles 100% positively correlated with the four demand profiles (left) and 100% negatively correlated with demand profile (right).

It is clear that the correlation does play a role in the cost reduction potential of wind power. In the situation of a positive correlation between demand and wind power output, the electricity provided by wind acts as a sort of peaking unit, diminishing the need for other power plants that have to flatten out a bump in demand. Wind power can reach its maximal cost reduction potential this way. A negative correlation on the other hand seriously limits the fuel cost saving potential of wind power. The energy generated by wind power does replace energy delivery from other sources. However, this fuel saving is compensated by the severe efficiency losses in the operation of the electricity generation system. Therefore, not only the composition of the system is important, but also the relation of its demand with the wind power provision. These effects are logically more predominant in less flexible systems, such as the *coal* system.

[116] It has to be noted that the wind speed profiles corresponding to *Day 1* and *Day 4* result in distinct levels of overall wind-generated electricity. Therefore, the absolute differences between *Day 1* and *Day 4* cannot be compared.

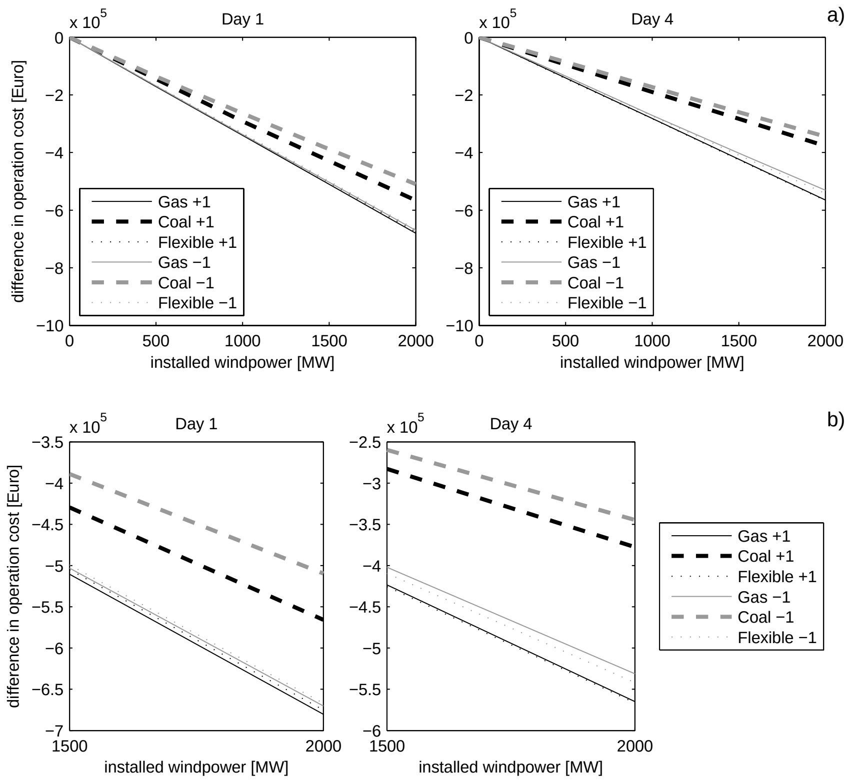

Figure 54: The difference in operation cost for the wind speed profiles that have a correlation of "+1" or "-1" with demand. Figure 8a shows the range from 0 to 2000MW installed wind power capacity. Figure 8b shows a close-up of the values for 1500 and 2000MW.

8.4.1.4 Impact of the size of the system

Another element that plays a role in the composition of electricity generation systems is the size of this system and corresponding demand. Larger systems have more opportunities to deal with changes. Two elements influence the cost reduction potential of wind power in differently sized systems.

On the one hand, the previously mentioned marginal power plant will heavily depend on the size of the system as well. When a switch is made from a more expensive marginal plant to a cheaper one, the cost reduction potential decreases accordingly. It all comes down to the interaction of demand and the merit order in electricity generation. The more expensive the marginal power plant, the more operation cost savings will the system achieve through the introduction of wind power.

On the other hand, but to a much lesser extent, when comparing small and large systems with the same relative demand, the smaller system usually realises less operational cost savings than the large one. This is due to the fact that a large system, with corresponding larger demand, has more units in operation at any point in time and therefore will have more options for dealing with changes without having to start up new units. A cheaper operation of the system can be achieved by using active power plants since more options are synonym for more flexible operation of the system.

8.4.2 Fuel cost difference due to unpredictability of wind power

Apart from the variability of wind power, the relative unpredictability of wind power affects the operation of the system as well. The costs linked to an erroneous forecast are to be found in changes in the reserves to the system. Forecast errors depend on how much ahead the wind speed forecast is made. They have to be met by reserves that are available relatively quickly. As explained earlier, these reserves are referred to as power reserves.

For relatively low levels of installed wind power, a negative forecast error can reduce costs compared to the perfect forecast. The fuel cost savings due to the extra wind power are predominant. This is counteracted for higher installed wind power levels, where the necessary system adjustments for the forecast error bring about additional system costs. For positive forecast errors, both elements usually lead to cost increases compared to a correct forecast.

The more flexible an electricity generation system is, the less will the forecast error cost be. The necessary increase in reserves can easily be met by modern gas-fired combined cycle or coal-fired power plants. As previously mentioned, these do not loose much of their efficiency operating at partial load and therefore offer considerable reserve capacity to the system. This is only true for systems that do not continuously need to operate all their plants at full load due to underdimensioning of the generation capacity.

However, not only the actual real costs of the electricity generation should be looked at, also the opportunity cost of the power reserves that need to be foreseen to cover forecast errors, needs to be taken into account. Using prices obtained from the output of the operation model, the value of these power reserves can be determined. This value determines the opportunity cost of an extra value of reserves and can be used to valuate the decrease in reserves due to wind power uncertainty. It is clear that the chosen generation mixes are usually overdimensioned and that they benefit from a very flexible operation. These two elements lead to the shadow price of the power reserves constraint usually being zero. However, on some occasions, and specifically when a change in marginal power plant occurs, the additional requirements for power reserves due to a forecast error lead to a rise in opportunity costs, apart from the one in actual operation costs.

8.4.3 Greenhouse gas emissions effect

The impact of the composition of the electricity generation system on the integration of wind power can be evaluated through the GHG emissions reductions as well. Since wind power is considered a clean energy source, its contribution to emissions reduction is considered to be an important parameter. The parameters discussed above for the cost reduction effectiveness of wind power also influence the extent of GHG emissions reductions.

8.4.3.1 Impact of wind power integration on GHG emissions reduction

The GHG reduction potential of wind power has already been analysed before and is shown to behave sub-linearly with increasing amounts of wind power [93; 224]. In this section, the shape of the GHG emissions curve is further analysed in the light of the generation mix of the system.

For the *gas* and *flexible* systems, the GHG reduction is almost linear with the amount of installed wind power. This is also true for the *coal* system combined with a low demand. The reason is, again, to be found with the marginal plant. This remains the same over the increasing amounts of installed wind power. For the *gas* and *flexible* system, the marginal plant is always a combined cycle power plant, resulting in a GHG emissions saving per MWh of energy produced by wind power that by and large corresponds to the emission rate of the combined cycle power plant. For the *coal* system facing a low demand profile, the marginal plant is a coal-fired power plant. Due to the higher emission rate of the coal power plant compared to a gas-fired combined cycle power plant, the emissions reduction curve for increasing wind power is steeper for the *coal* system than for the two other systems, resulting in emissions savings of up to 25% for the case with *day 4* and *windday C*.

The interesting case is when the marginal power plant changes with increasing amounts of wind power. This happens with the *coal* system at high demand. The shift from 500 MW to 1000 MW wind power (a factor 2 rise) goes together with a GHG reduction of 7.90 kton to 16.43 kton (a factor 2.08). The GHG reduction corresponding to the shift towards 1500 MW and 2000 MW are even more important, namely a factor 3.23 and 4.46 compared to the reductions associated with 500 MW wind power. For low amounts of wind power, the marginal power plant is composed of a gas-fired combined cycle power plant. When this amount is increased over 500 MW however, a coal power plant becomes the marginal power plant, leading to more significant GHG emissions reductions for each MW of wind power once the installed wind power exceeds 500 MW. The emissions reduction curve in this specific case is supra-linear. The sub-linear curve mentioned in [93] and [224] are a result of different merit orders for the power plants in the system, more specifically a switch in the priority listing between gas- and coal-fired power plants.

8.4.3.2 Impact of CO_2-price on cost and emissions reduction with wind power integration

A logic result of a CO_2-tax or –permit system is the overall system operation becoming more costly due to increased taxes. The effect is most outspoken for the *coal* system, where the many coal power plants get taxed more than the gas based power plants due to the higher CO_2 emission rates of the former. This is also discussed in a more general context in [225].

The most important consequence of a significant CO_2-tax is the switch between gas- and coal-fired power plants in the stacking order of the power plants in the operation of the electricity generation system. With a CO_2-tax of 25 €/ton CO_2, gas becomes relatively cheaper as a fuel compared to coal[117]. The gas-fired combined cycle power plants move to the base load for electricity generation, thereby outperforming coal-fired power plants. The main result of this switch is a change in the marginal power plant, which in turn influences the cost and emissions saving capacity of wind power introduction into the different systems. With the gas power plants generating base load, the cost savings curve has a sub-linear profile. A dent in the curve can be

[117] The exact level of CO_2-tax at which the switch as base load providers between coal- and gas-fired power plants takes place, falls outside the scope of this thesis. More information on this switching level can be found in [226].

observed when the marginal power plant switches from a coal- to a gas-fired power plant. The GHG emissions reduction curve however, also behaves sub-linearly in this configuration. A relatively steep decrease in coal usage and related emissions can be observed for the first additions of wind power. When the coal power plants become obsolete in electricity generation, the decrease in GHG emissions is achieved though avoided usage of gas-fired power plants, which automatically coincides with less important reductions than when coal-based emissions are avoided.

8.5 Conclusion on the impact of the electricity generation system composition on wind power

The previous sections highlighted aspects of the composition of electricity generation system and the impact it has on wind power integration. With the introduction of wind power into an existing system, the operation of the system will adapt itself to the new situation. The manner in which the system will adapt depends, amongst others, on the system itself.

Various countries have different electricity generation systems. In the previous, three typical compositions of one system are chosen so as to illustrate the specific behaviour of diverging systems on wind power introduction, referred to as the *gas*, *coal* and *flexible* systems. A certain amount of wind power is integrated into these systems. Four typical demand patterns and four wind speed profiles are used to investigate the effect of these parameters. The effect of the system design, load and demand pattern and total amount of installed wind power on both cost saving and emissions reduction is investigated.

The cheaper fuels such as coal undergo a smaller impact on operational cost saving and increasingly so when faced with lower demand profiles. For lower demand, the cost saving potential of the systems operating cheaper and typically less flexible power plants decreases whereas it remains at the same level for the flexible gas-fired options. The reasons are found to be related to the flexibility of the operation of the system and the marginal power plant. With increasing amounts of wind power, a shift in marginal power plant may occur, which leads to changes in cost saving potential and GHG emissions reduction efficiency of wind power. The marginal power plant may shift from a gas-based to a coal-based plant by introducing a CO_2-tax, thereby rendering coal power plants less interesting.

However, the full potential of cost savings from the energy produced with cheap wind power plants is never reached due to its variability. The comparison of two identical wind energy outputs, respectively representing a flat and very fluctuating wind speed profile illustrates this. The efficiency losses due to the added variability in the system partially compensate for the fuel savings. The system needs to operate at lower efficiency to cover the wind power variability, leading to additional fuel and startup costs. The effect is dependent on both the composition of the system and the demand it is faced with. A second exercise goes deeper into the relationship between demand and wind power output. A positive correlation between demand and energy from wind power clearly benefits the cost savings. This is true for all of the considered generation mixes.

Apart from variability of wind power, the unpredictability and ensuing wind speed forecast errors affect the cost reduction potential as well. Two elements come into play. On the one hand, an erroneous forecast will usually lead to increasing operation costs to cover the reserves adjustments in the system. On the other hand the direction of the forecast error can lead to additional wind power output, which is beneficial for fuel cost savings, or to less wind power output than forecasted, which reduces the cost savings potential even more.

The effectiveness of wind power introduction in the light of GHG emissions reduction is dependent on the average emission rate of the power plants under operation in the system. Typically, the largest reductions in GHG emissions are obtained in the more polluting systems, where wind power is outperforming coal power plants. The impact of the system on GHG emissions is practically in contrast with its impact on the cost reduction. Whereas the gas-based systems benefit most from wind power in terms of cost, it is the coal-based systems that see the most reductions in GHG emissions with the introduction of wind power. By imposing a CO_2-tax, wind power can more effectively reduce GHG emissions in any system.

The originality of this chapter is based on the comparison of different electricity generation systems and the interaction with installed wind power. Usually the integration of wind power in a system is investigated from the point of view of one specific country. It gives a biased and very system-specific result. This chapter does not start from one determined context but takes a more general view on the backup costs of wind power in three different generation mixes. It is crucial to know how the system composition influences the integration of wind power, with respect to costs and GHG emissions. The operation of a gas-or coal-based system with wind power is different. Moreover, to get a more thorough study of the impact of both the availability and variability of wind speed on the costs, several extreme wind speed profiles are used. Also the influence of the forecast error of wind power is investigated in this chapter, to get a complete impact analysis of wind power.

PART 4

Summary, Conclusions, Innovative Aspects and Recommendations

9. SUMMARY, CONCLUSIONS, INNOVATIVE ASPECTS AND RECOMMENDATIONS

This final chapter gives an overview of the main results and formulates a conclusion on the backup of wind power. The innovative aspects of the thesis are briefly stressed as well. Since research is never really finished, recommendations for further research are also provided in this chapter.

9.1 Summary

The introductory chapter showed the need for a better understanding of wind power integration in electricity generation systems. Wind power will be important to reach the European targets for greenhouse gas emissions reduction and electricity generation from renewable energy sources.

A first part in the thesis covers the elements needed for a better understanding of wind power integration in electricity generation systems. It is important to bear in mind that electricity from wind power originates from a natural, intermittent source. It offers certain advantages in terms of emission reduction and cheap electricity generation. Disadvantages to wind power also exist and can be linked to the variability and relative unpredictability of wind power. These two elements make up its intermittency and to a large extent define why wind power is different from other electricity generation sources. To ensure a good understanding of the particular behaviour of wind power, the process of transforming wind speed to wind power is also covered in the first chapter.

When describing the integration of wind power in electricity generation systems it is essential to have a good notion of how these systems are operated. Both cost-efficiency and reliability are key in the operation of wind power. Reliability relates to the long term system adequacy and the short term security. The former defines how the system can comply with demand requirements at all times. The latter refers to the system’s ability to withstand sudden disturbances. The cost-efficient design and operation of a system is a logical consequence of using scarce resources in the most optimal way.

The impact of wind power on the operation of electricity generation systems becomes most apparent when comparing a system with and without wind power. To meet a given demand, both systems apply a different merit order for covering the same demand. Wind power clearly interacts with the merit order of the system and consequently influences elements such as operational cost and greenhouse gas emissions. The interaction of wind power with the rest of the system also implies that both variability and relative unpredictability can be evened out. Because none of the elements in the electricity generation system are perfectly correlated, their fluctuations and forecast errors will be smoothed when considered as a whole, as opposed to considering each element separately.

To allow for an in-depth analysis of the different parameters determining the impact of wind power integration in electricity generation systems, this thesis uses two models. A first unit commitment / dispatch model simulates the operation of electricity generation systems. The simulation is performed, based on a mixed integer linear programming (MILP) approach under cost minimisation for the unit commitment and a simple linear programming approach, also under cost minimisation, for the dispatch phase. During the unit commitment phase, electricity generation units are assigned to a certain demand, taking into account the technical constraints such as minimum and maximum operation point, ramp rates, efficiency levels, minimum up and down times, fuel costs and necessary reserves. During the unit commitment no full certainty exists. Demand and, in this case more importantly, wind power output is subject to certain forecast errors. The available units are then dispatched on an hour-to-hour basis. During the dispatch phase, the actual wind speed level becomes clear and final balancing of demand and electricity generation can be achieved.

A second reliability model, applied to an adapted IEEE test system is used for the determination of several key adequacy indices. These are important in the evaluation of the reliability of electricity generation systems with wind power integration. The model serves as a tool for the calculation of the capacity credit of wind power as well, which can be used for defining the long term contribution of wind power to the system.

A second part in the thesis focuses on the short term aspects of backup for wind power. The impact of forecast errors is closely investigated. One of the options for coping with increased wind power levels in the system is through assigning more power reserves that serves as backup for the forecasted wind power. A full backup through power reserves is possible up to some extent but becomes very expensive for high levels of wind power. The imbalance charges for parties that are responsible for balancing wind power are also examined. Different imbalance tariff mechanisms exist for different countries. Countries such as Belgium and the Netherlands where marginal cost pricing for imbalance tariffs prevails, usually give rise to higher imbalance costs. Countries such as France and Spain benefit from a more interesting average cost pricing of imbalance charges. The penalties the transmission system operator imposes on top of the marginal or average cost pricing has a significant impact as well. The Netherlands, for example, do not charge any margin on top of the marginal cost and will therefore offer a rather attractive regime to the balance responsible parties. Belgium and France impose rather high penalties and see their imbalance charges rise higher. When integrating wind power in electricity generation systems, it is obvious that the prevailing imbalance charge system greatly influences the backup of wind power.

The storage of energy is investigated as well. Two options, namely pumped hydroelectric storage and storage of heat produced by heat pumps are closely examined. Concerning the pumped hydroelectric storage, it can be interesting to dynamically adapt the amount of available storage capacity that is assigned to either peak shaving or capacity reserve provision. For high wind speeds and low demand levels, more storage capacity can be assigned to the reserve provision, whereas allocating the available storage to peak shaving is most interesting for high demand levels and low wind speeds. The usage of heat pumps in combination with heat storage to absorb the electricity generated by wind power can offer two benefits. On the one hand, it can help reducing overall greenhouse gas emissions since the heat pumps offer an efficient option for heat production. On the other hand, through integrating wind power output directly in the heat system, the electricity generation system does not need to cope with the additional electricity generation of wind power.

In the third part of the thesis, the long term backup of wind power is covered. A reliability model is used for determining the impact of increasing levels of wind power on the capacity credit. For the four adequacy indices used, namely Loss-of-load expectancy (LOLE), Loss-of-energy expectancy (LOEE), Loss-of-load frequency (LOLF) and expected interruption cost (EIC), the capacity credit is found to decrease. The location of the wind farm in the systems is found to have an impact on the evolution of the reliability as well.

When considering the long term backup of wind power, the system composition plays a central role. Electricity generation systems composed of more flexible generation units are found to be more adequate for the integration of wind power. They are better suited for adaptation to the fluctuating wind power output profiles.

This effect is most outspoken when considering extreme wind speed profiles, going from flat to oscillating profiles and from profiles that are negatively correlated to demand to profiles with a positive correlation.

9.2 Conclusions

The described research in the previous chapters, investigating the impact of wind power in electricity generation systems has one common aim, namely proving the existence and analysing the extent of the interaction of wind power with the electricity generation system. Wind power, just like any other electricity generation source, cannot be seen on its own. For a correct interpretation of the operation of wind power, the dynamic context it operates in needs to be known as well.

The investigation of wind power in electricity generation systems is evaluated according to three criteria, namely operational cost, system reliability and greenhouse gas emissions reduction. Several crucial parameters that influence the impact of wind power on the three criteria, such as wind speed and demand profiles, system design, fuel prices and total amount of installed wind power, are considered. The main focus is on the electricity generation system, with less attention to the transmission and distribution grid impacts.

The reciprocal influence of wind power and the electricity generation system can be seen within two time frames, namely the short and the long term. The two constituent elements of the intermittency of wind power, namely relative unpredictability and variability are related to this subdivision in short and long term. The relative unpredictability of wind power can be linked to the short term, whereas the long term is associated with the variability of wind power. Both relative unpredictability and variability give rise to a need for backup of wind power.

On the **short term**, the relative unpredictability of wind power causes forecast errors on the instantaneous power at moment of operation. This error causes an imbalance of the wind power generation. Since for electricity delivery, demand needs to equal generation at all times, any imbalance has to be dealt with.

When looking at individual market players instead of the system as a whole, the transmission system operator (TSO) is the final responsible for clearing out any imbalance in the system. Additional costs for negative imbalances or remunerations for positive imbalances are passed on to the parties causing the imbalance. It is obvious that with increasing amounts of wind power in electricity generation systems, the forecast errors and matching imbalances need to be closely followed. The way imbalance costs, incurred by the TSO, are passed on to the Balance Responsible Parties (BRPs) operating wind power, varies between countries. Policy choices determine whether single or dual imbalance prices are used and whether, average or marginal pricing is charged for imbalances by a BRP. Also the level of imposed penalties for BRP imbalances is a matter of choice. Average pricing is found to be beneficial to BRPs operating wind power, compared to marginal pricing, with Spain constituting the cheapest example in the performed investigations. Average pricing alone is not enough to ensure a cheap outcome in terms of imbalance charges. France is a good example of a country where the additional penalties and price caps for the imbalance charges lead to comparably expensive imbalance costs. Belgium adopts an imbalance tariff mechanism similar to the French system, with the difference of applying even more price caps and charging marginal costs to the BRP. The Netherlands apply a straightforward system for forwarding the imbalance costs of TSOs to the BRPs, only relying on the marginal costs, without any penalty being applied, thereby offering a relatively interesting imbalance mechanism for wind power. When redesigning imbalance tariff structures, the impact on wind power imbalance costs needs to be addressed as well. The system should be such that a BRP is encouraged to have the best possible wind speed forecast for declaration of its unit commitment to the TSO. At the moment, bidding strategies can choose not to use the best possible forecast for profit maximisation. Not necessarily the cheapest design but the design offering the best incentives for optimal operation of wind power should be strived for.

Various measures exist to effectively cope with imbalances in the system. However, with changing situations in the electricity generation system due to the integration of increasing amounts of wind power, the best approaches for imbalance management can change correspondingly. It is therefore important to get a good view on the determining factors for imbalance management. Various sources for reserve power, used for imbalance management exist. One analysed approach is the full backup of forecasted electricity from wind power with power reserves. While this approach does not constitute a high additional operational cost for the system at low levels of installed wind power, the reservation cost rises steeply with increasing amounts of electricity generated by wind power. This is especially true for low levels of demand. For high levels of demand and relatively low forecasted wind-generated electricity though, sufficient power plants, operating at partial load, are available for cheap provision of power reserves.

It is clear that other measures than keeping power reserves available are needed for cost-effective balancing of wind power, such as the use of energy storage through pumped hydroelectric storage (PHES) or through heat storage. PHES can fulfil two purposes, namely providing balancing reserves and peak shaving of demand. If all of the PHES capacity is allocated to balancing wind, this constitutes a significant opportunity cost for the system. It is key to use the PHES resources intelligently, attributing the PHES capacity to both balancing and peak shaving. The fractions allocated to both uses of the PHES need to adapt to the circumstances. With high wind speeds and important forecast errors, more importance should be attributed to balancing purposes. With high and variable demand levels and low levels of electricity from wind power, a higher share of PHES for peak shaving has to be maintained. The intermittency of wind power can also be dealt with by using efficient heat pumps that will store the energy under the form of heat. When a continuous demand for heat exists, the combination of wind turbines and heat pumps with heat storage factually replaces the use of conventional heating. Reductions of costs and greenhouse gas emissions can be achieved and the intermittency of wind power can be absorbed by the heat storage.

The need for backup of wind power can be seen on the **long term** as well. An amount of installed wind power has a certain capacity credit, relating the wind power to system reliability. It describes how much a wind power investment contributes to the adequate operation of the electricity generation system, in comparison with other generation units. As far as capacity credit is concerned, it has been shown that different adequacy indices exist as a reference for its calculation. For relatively low amounts of installed wind power, the capacity credit can be estimated by the capacity factor. For increasing levels of wind power however, the capacity credit decreases for each of the applied adequacy indices, indicating the difficulties of the system to absorb the wind power. The location of wind farms also has an impact on system reliability. Well-connected locations, close to demand centres are to be preferred.

Multiple factors influence the value of wind power on the long term, in terms of cost-effectiveness, contribution to system reliability and emissions reduction. Firstly, the average wind speed level highly impacts the contribution of wind power to electricity delivery in the system. The first wind turbines in a system replace the marginal power plants, representing the most expensive plants. With increasing levels of electricity generated from wind power, wind power outperforms cheaper power plants in the merit order. The incremental operational cost saving of wind power decreases with increasing wind power capacity.

Next, the system composition plays an important role in the determination of the long term value of wind power as well. Systems that are composed of more flexible units such as gas-fired power plants have an advantage over less flexible systems when it comes to wind power integration. The impact is dependent on the relation between demand and wind speed profile and on how pronounced the fluctuations of the wind speed profile are. When wind speed is positively correlated to demand, more cost savings can be obtained than when a negative correlation is noted, especially in systems being composed of less flexible units such as coal-fired power plants. In terms of fluctuations of the wind speed profile, a flat profile is found to increase the value of wind power in terms of cost reduction. A heavily fluctuating profile imposes certain efficiency losses on the system with power plants having to operate at partial load more often. The system composition also determines the greenhouse gas emissions reduction impact of wind power. Whereas gas-dominated systems benefit most from wind power in terms of cost, the coal-based systems undergo the largest reductions in emissions with wind power introduction. By imposing a CO_2-tax, wind power can more effectively reduce emissions in a system.

The existence of multiple factors influencing the integration of wind power in electricity generation systems has been clarified in this thesis. The ease of integrating wind power depends on how all these parameters relate to one another. The need for a good assessment of how wind power interacts with various systems elements is stressed and various analyses have investigated this interaction. The research in this thesis offers insight in many of the parameters influencing wind power integration both on the short and long term. A full understanding of the interaction of wind power with electricity generation systems only comes with continued research effort. For this purpose, the next section offers various recommendations for further research.

9.3 Innovative aspects of the thesis

As stated in the previous section this thesis aims at providing a better understanding of the interaction between wind power and the electricity generation system. The innovative aspects are based on three pillars. Firstly, a general context of wind, electricity generation systems and their interactions is offered. Secondly, methodologies on how to investigate different key aspects of the interaction are explained. Finally, applying these methodologies, new insights are gained.

The general context, mainly offered in Part 1, has the main merit to outline the bigger picture in power integration in systems. Indeed, to fully understand the interaction between wind and the system, a structured overview of the relevant elements is essential. This is done through extensive literature survey, clear definition of the used concepts, personal insights and new analyses on specific factors of interest.

In Part 1, particular attention is given to the different time frames in which wind operates. Wind is proven to vary less on shorter time frames, to have a higher average speed during daytime and to be geographically smoothed. The statistical properties of wind are introduced and some examples are given of the dynamic behaviour of wind turbines, demand and the other power plants in the system. The fourth chapter introduces the two principal models, used in Part 2 and 3. The MILP model, developed at the K.U.Leuven, at the division of Applied Mechanics and Energy Conversion by Delarue, is adapted to specifically investigate the impact of wind power on the system. The scenarios in later chapters are chosen to best simulate the actual behaviour of an electricity generation system with considerable amounts of wind power. The reliability model builds on the IEEE '96 Reliability test system and is used in chapter 7 to calculate different adequacy indices. The novelty of the applied reliability assessment is the combination of different elements, such as the calculation of four different adequacy indices, the application of Monte Carlo simulations for determination of an average outcome and the use of Markov matrices to generate an unlimited amount of wind speed time series.

In Part 2, short term analyses are based on the MILP model. In chapter 5, two aspects of the relative unpredictability of wind are examined. Firstly, a comparison of different scenarios with 100 % additional reserves simulates the situation when wind power is taken to be non-firm capacity. This is an extreme case that gives a better understanding on how a system can handle additional reserves obligations. Secondly, the imbalance tariffs, not only in terms of the actual rules but also in terms of impact on wind power imbalances, are studied. Usually, imbalance tariffs are investigated through average historical values. The adopted approach in this thesis takes the actual dynamic imbalance rules of four different countries into account. This gives a better view on the actual impact of imbalance tariff designs, which is useful in times of harmonization of power markets.

Also in Part 2 but in chapter 6, the innovation relies on two elements. Firstly, the storage of wind-generated electricity in PHES is dynamically analyzed. The two main functions of PHES, namely balancing and peak shaving, are both weighted against each other, while taking the interaction with an entire electricity generation system into account. The interaction with an entire system is mostly not part of the research on PHES and wind power. Secondly, the heat pump with thermal storage exercise offers a different perspective on the integration of wind power. Not injecting the electricity from wind power in the system but using it locally for heat production can offer interesting alternatives. It is good to know that, under the right circumstances and with evolving heat generation and storage technologies, other cost and GHG emissions saving options can be found for wind power.

In Part 3, chapter 7 offers an interesting methodology to quantify the capacity contribution of wind power. The widely used concept of capacity credit is defined and, applying the reliability model from chapter 4, a complete calculation of this capacity credit is proposed. No new concepts are actually introduced. The combination of existing principles to reach one final goal constitutes the key novelty in this chapter. Different adequacy indices are used to evaluate the system adequacy and to form the basis for the capacity credit calculation. Another addition to the regular determination of the adequacy is the calculation of the indices through Monte Carlo simulation combined with the use of Markov matrices for an unlimited number of wind speed profiles as input. Finally, for optimization of computation time, a curve fitting on the calculated adequacy indices gives a continuous range for the allowed increase in peak demand, needed for the exact determination of the capacity credit.

The last research chapter of this thesis, also within Part 3, investigates the impact of wind power on different system compositions. Usually, when the integration of wind power in a system is investigated from the point of view of one specific country, it has a very system-specific outcome. Chapter 8, on the other hand, does not start from one predetermined context. It analyzes the cost and GHG emissions reduction impact of wind power for three different systems. Also extreme wind speed profiles are used in the analyses, to get a clear idea on the impact of availability and variability of wind. A forecast error is introduced in the systems to investigate the unpredictability of wind power.

9.4 Recommendations for further research

The research opportunities on the backup of wind power are vast. Many possible approaches can be applied to this research. The study of the backup of wind power is far from being finished with the research presented in this thesis. A non-exhaustive list of possible focuses for further research is offered in this section.

9.4.1 Additional investigation on the imbalance settlement for wind power

9.4.1.1 Modelling the imbalance cost

Instead of using a function based on historical data for the determination of values such as reference market price (RMP) and marginal and average price for upward and downward regulation (MP and AP) as described in chapter 5, the cost figures can be modelled using the MILP approach. Using the shadow price of the reserves that are used in the model, instead of calculating the MP from historical data, gives a better idea of the actual cost of imbalances in the system[118]. It uses the dynamics of the model to get a clear idea on the cost of electricity generation in the particular case modelled. The marginal cost of the actual electricity provision can serve as the RMP under the assumption of perfect market mechanism where the marginal cost equals the marginal revenue, which determines the price.

This approach of modelling RMP and MP also has a disadvantage, namely that no direct cost can be attributed to the reservation of this reserve. In reality, bids for imbalance power provision, which can be both upward and downward, are contracted in advance and are not based on perfect information either. They will not reflect their actual provision cost since this cost is not perfectly known in advance.

The approximation of the cost for reserves usage can be considered a lower limit for the actual marginal cost for upward or downward regulation. From this point of view, it might prove to be an interesting exercise.

9.4.1.2 Using different electricity generation systems for the investigation of imbalance tariffs

Another interesting analysis of the imbalance tariffs can be made by taking different reference systems into account. So far, only the Belgian system has been used, with its own functions for the reference market price and marginal and average cost. Taking different systems as reference might shed a light on how the diverging compositions of these systems and the resulting different evolutions of costs impact

[118] Using the shadow prices with MILP problems has to be done with extreme care since they are only meaningful for convex problems. Shadow prices with a MILP model can only be considered approximations. When doing a shadow price analysis, a regular convex LP should be taken as basis.

the imbalance cost for wind power. To perform such analysis, a good knowledge of the system is needed.

Comparisons of results using different systems as a reference becomes difficult since the sizes will obviously differ. The outcome might however still be interesting since it can partially explain how certain systems are better suited for balancing large amounts of wind power. It is logical that larger electricity generation systems and systems with more flexible generation have better options in terms of imbalance settlement of wind power.

Each system has its own imbalance *regulation cost ladder*, based on the available power plants for reserve provision and therefore on the composition and operation of the system. France for example, has a critical dent in the upward regulation curve around 2400 MW. It can be interesting to compare the different countries in this light as well and to look further at interconnection possibilities with countries that can more easily balance wind power.

9.4.1.3 Apply new imbalance tariff system, based on more general conceptions and taking wind power into account

Until now, only existing imbalance tariff systems have been investigated. These are usually designed to balance entire systems and are based on different concepts in each country. An interesting exercise could therefore consist of examining past countries' preferences and investigate simple imbalance settlement options, with or without exemptions for wind power.

In this view, the Belgian exemption of 10% and 30% imbalance for onshore and offshore wind power respectively could be investigated in terms of technical justification. If the exemptions are found to have a practical ground, applying them in other countries could be envisaged.

9.4.2 Pricing the reserves

The marginal cost for power reserve capacity can be determined for both the unit commitment and the dispatch phase in the described MILP model. Changing the amounts of required power reserves in fixed steps and simulating for each step can give a cost ladder or merit order function for capacity reserve. This can be used for purposes of imbalance settlement, as explained in 9.4.1.1. It has to be taken into account however that changing the reserve needs, not only impacts the cost for reserve but also its availability and hence the reliability of the system. Nevertheless, it might be an interesting exercise to investigate the cost ladders for capacity reserve.

To get more meaningful results, it might be a good idea to choose more extreme flexibility parameters for individual power plants. Combined cycle power plants operate almost as efficiently at 50 % or even 30 % of their installed capacity as when they operate at full load. It can therefore be interesting to also look at systems where this flexibility is not available and where consequently more has to be paid for keeping reserves available.

Another parameter that determines the cost for power reserves is the available margin between peak demand and available power generation capacity and how long the peak demand lasts over a given time span. When this margin is limited fewer options remain for providing power reserves in the system, thereby increasing the cost for power reserves.

9.4.3 Additional reserves analyses

The reserves used in the MILP approach have been taken as a fixed amount of power, mainly meant to be able to cover the outage of the largest unit in the electricity generation system. Other approaches on this amount of power reserves can be adopted. For example, it can be argued that less power reserves are needed at times of high certainty regarding the output or when demand is low and fewer power plants are subjected to possible unforeseen outages.

Also, a more in-depth analysis of the correct amount of reserves to be foreseen for wind power can be made. Since the wind power forecast error behaves as a standard normal distribution [31; 227], one method for reserve provision could be to foresee three to four times the standard deviation of the wind power output forecast. Alternatively a fixed amount of reserves could be foreseen in relation to the installed wind power. This reserve would then depend on the intercorrelation of the different wind farm sites, the interaction with other forecast error, the total amount of wind power installed and the chosen level of accuracy for the forecasts.

Another interesting exercise might be the investigation of negative reserves, referring to occasions where more electricity is produced than what had been forecasted and where the system actually has to produce less than what had been forecasted. This also can be quantified through the use of the shadow price of the reserve constraints in the MILP model.

Finally, also the difference between costs in the UC and dispatch phase can be compared. The marginal costs in dispatch phase can be considered to set the day-ahead spot market price, while the marginal cost of dispatch can refer to the price on a real-time balancing market. This concept can be applied both to the cost of system operation as to the cost of reserves.

9.4.4 Further reliability assessment of wind power in electricity generation system

The reliability of electricity generation systems with the inclusion of wind power remains an important matter in the study of wind power. Additional analyses, applying the method described in 4.3 can be envisaged to gain more insight in the impact of wind power on system reliability. For instance, a different composition of the system can be investigated to determine the impact of wind power on the system reliability. Furthermore, the interconnection of systems can also improve the reliability of wind power. Also different measures to improve wind power integration can be compared. In order to meet increased demand with wind power and keep the same reliability level, investments in generation units as well as grid expansion can be envisaged. Finally, the influence of geographical dispersion of wind power on the system reliability can be analysed.

The capacity credit of wind power is one of the parameters to express the value of wind power on the long term. It can be calculated as explained in 7.1. Alternatives to a full simulation of the system to calculate the capacity credit exist. One that deserves special attention is described by Voorspools and D'haeseleer [211]. With a large number of capacity credit data for one system, the approximation proposed in [211] can be improved. Moreover, using the adequacy indices from 4.3, a better approximation of system reliability can be used. Furthermore, a better indicator for the dispersion of wind turbines can be used, for example by taking the correlation factors of wind speeds at different locations. Finally, the reliability of conventional plants can be linked to the desired system reliability.

A third element for improvement in the reliability analysis is the inclusion of the yearly demand function as one of the random variables, instead of calculating the reliability for a given demand profile. Obtaining a number of yearly demand data can open the perspective for a Markov chain approach of the demand function. Once

Markov chains are known, demand profiles with the same statistical qualities can be generated and used as input for the reliability assessment in the Monte Carlo approach. For the determination of Markov matrices, a considerable amount of demand profiles is needed.

9.4.5 Compare uncertainty of wind power with conventional generation

Looking at the uncertainty of wind power, mainly the forecast error comes to mind. Apart from that, there is also a relatively small probability of technical failure or unforeseen outage of a wind turbine.

The uncertainty related to conventional generation units such as a gas-fired combined cycle power plant are almost exclusively related to unforeseen outages. The question rises whether both types of uncertainty can be compared to one another since they have different origins. Moreover, a forecast error for wind power occurs in both negative and positive direction, bringing its uncertainty to another level.

These elements lead to believe that wind power cannot just be regarded in the same way as conventional electricity generators. It remains however interesting to think about ways to be able to relate uncertainty from conventional power plants to the one stemming from wind power. They do operate jointly in electricity generation systems and it is important to have a good view on how the global uncertainty and related costs of the system can be minimised. Concerning system uncertainty, there is probably a good balance to be found where both conventional generation and intermittent sources contribute to the overall value of the system’s reliability.

9.4.6 Investigate the operation of electricity generation systems with wind power on time frames shorter than one hour

In the performed analyses in this thesis, hourly wind speed data are used. As mentioned in section 1.4, wind speed behaves differently on different time scales. It can be expected that variations within the minute have a different impact on the operation of the electricity generation system than the hourly variations. For one, the ramp rates of power plants will become a more stringent constraint when considering evolutions over minutes than over hours.

The difficulty in this is to obtain adequate data for very short term wind speed. Electricity generators, for example in Belgium and Germany, usually keep track of 15-minute electricity generation but apart from that it might prove difficult to get more detailed data.

Interesting to study could be the impact of having 15-minute time steps for the imbalance settlement and comparing the results with the hourly imbalance settlement.

9.4.7 Analysis of the real cost of wind farm investments in low-wind areas

Many current wind farm projects are situated in areas with less than optimal wind speed conditions. It can be interesting to look at the financial and technical consequences of opting for these locations.

9.4.8 Analysis of the impact of massive use of plug-in hybrid cars as a storage medium for wind power

As explained in chapter 6, plug-in hybrid cars, connected to the grid, can help reducing the impact of intermittent sources such as wind energy. With a vast plug-in hybrid car park in a given system, the many batteries of these cars can offer some storage options for wind power. It could be interesting to look more closely at the impact of such grid-connected car park on the operation of electricity generation systems with wind power, in the same logic as the analyses of chapter 6.

9.4.9 Multiple electricity generators that interact with each other

The research performed so far considers the electricity generation as a whole or the behaviour of one electricity generator. An interesting exercise could consist of using the same techniques to investigate the impact of different electricity generators, supplying the same market. This approach can shed more light on interactions between different players in the electricity generation system.

9.4.10 Investment model for the determination of optimal system composition with wind power

An alternative way of investigating the system composition impact on wind power integration is to construct an investment model that builds up an electricity generation system from nothing. With a given demand function and a certain constraint on pollution, different types of power plants are chosen by the model. At this point only fuel price and technical characteristics influence the outcome. Next, wind power can be allowed to enter the generation mix. With varying amounts of support mechanisms for wind power, increasing penetrations will occur. This enables the determination of the required level of subsidies necessary for a given investment in wind power.

Appendices

Appendix A
The Belgian electricity generation system

Power plant	Installed power [MW]
Nuclear	5825
Coal	1719
Natural gas conventional	1281
Natural gas combined cycle	3398
Gas turbines	178
Diesels	107
Turbojets	228
Blast Furnace	274
Waste	132
CHP	879
Hydropower	80
PHES	1307
TOTAL	**15408**

Table 31: The Belgian electricity generation system, used as reference system in the simulations applying the MILP model.

Appendix B
Markov matrices

Hour H+1 \ Hour H (m/s)	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
0	30.4%	49.6%	15.1%	1.3%	1.7%	0.7%	0.0%	0.0%	0.6%	0.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
1	10.1%	57.8%	26.0%	4.9%	0.5%	0.3%	0.0%	0.2%	0.1%	0.0%	0.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2	2.5%	17.6%	51.3%	22.9%	3.7%	0.9%	0.7%	0.3%	0.0%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
3	0.3%	3.7%	20.5%	55.3%	17.1%	2.2%	0.7%	0.1%	0.1%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
4	0.1%	0.9%	4.8%	22.3%	48.5%	16.9%	4.4%	1.2%	0.6%	0.2%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
5	0.0%	0.1%	1.2%	5.3%	22.7%	42.3%	20.0%	5.7%	1.5%	0.9%	0.3%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
6	0.1%	0.2%	0.3%	2.2%	6.4%	25.5%	40.7%	17.3%	4.8%	1.4%	0.5%	0.4%	0.1%	0.1%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%
7	0.0%	0.0%	0.5%	0.2%	2.8%	7.9%	22.1%	41.3%	16.2%	5.8%	2.0%	0.7%	0.4%	0.1%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%
8	0.0%	0.0%	0.0%	0.5%	0.3%	2.8%	8.6%	24.4%	36.5%	18.1%	5.3%	2.2%	0.5%	0.5%	0.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%
9	0.0%	0.1%	0.4%	0.3%	0.8%	1.8%	3.6%	12.5%	23.8%	29.7%	17.9%	6.8%	1.6%	0.2%	0.1%	0.0%	0.3%	0.3%	0.0%	0.0%	0.0%
10	0.0%	0.2%	0.0%	0.0%	0.0%	0.4%	1.5%	1.2%	6.7%	28.7%	34.4%	18.1%	6.0%	2.3%	0.0%	0.6%	0.0%	0.0%	0.0%	0.0%	0.0%
11	0.3%	0.5%	0.0%	0.0%	0.0%	0.4%	0.8%	2.6%	4.7%	14.2%	24.5%	22.6%	18.5%	6.0%	2.9%	1.7%	0.4%	0.0%	0.0%	0.0%	0.0%
12	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%	0.8%	1.0%	5.2%	9.9%	18.6%	43.2%	17.1%	2.6%	1.2%	0.0%	0.2%	0.0%	0.0%	0.0%
13	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.4%	2.0%	0.0%	3.4%	6.2%	15.0%	19.2%	34.7%	10.5%	5.6%	2.0%	0.3%	0.4%	0.6%	0.0%
14	0.0%	0.0%	0.0%	0.2%	0.0%	0.0%	1.0%	1.0%	0.7%	2.6%	0.0%	16.2%	22.7%	18.5%	30.0%	5.7%	0.4%	0.0%	0.0%	0.0%	1.0%
15	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.1%	0.8%	1.0%	1.0%	20.3%	18.9%	15.3%	25.3%	10.8%	0.3%	2.3%	0.0%	2.1%
16	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	3.6%	0.0%	5.9%	0.0%	3.2%	0.1%	1.8%	17.9%	14.1%	44.0%	9.3%	0.0%	0.0%	0.0%
17	0.0%	0.0%	0.0%	0.0%	0.0%	7.9%	0.0%	0.0%	0.0%	0.0%	0.0%	7.9%	0.0%	4.1%	0.1%	7.0%	25.1%	42.0%	1.8%	4.1%	0.0%
18	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	15.7%	0.0%	0.0%	0.0%	15.7%	11.8%	3.5%	10.5%	26.2%	6.5%	10.0%	0.0%
19	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	30.9%	0.0%	0.0%	0.0%	0.0%	0.0%	26.3%	24.1%	0.0%	18.7%
20	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	65.9%	0.0%	29.3%	0.0%	0.0%	4.8%

Table 32: Markov matrix for the first hour of the year. Each cell gives the probability that at the hour H+1 a certain wind speed will be reached, given a specified wind speed at H.

		Hour H																				
	m/s	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Hour H+1	0	12.9%	50.3%	17.8%	14.7%	1.6%	2.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	1	2.3%	30.3%	42.0%	18.9%	4.8%	1.2%	0.2%	0.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	2	0.5%	8.4%	36.8%	35.4%	13.6%	3.7%	0.8%	0.4%	0.2%	0.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	3	0.2%	1.5%	13.9%	44.8%	30.1%	6.7%	2.2%	0.3%	0.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	4	0.1%	0.1%	3.2%	16.8%	45.2%	24.8%	7.0%	1.8%	0.7%	0.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	5	0.0%	0.3%	0.5%	3.5%	18.5%	43.2%	24.8%	6.3%	2.2%	0.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	6	0.0%	0.2%	0.2%	0.8%	2.8%	21.9%	43.8%	23.8%	5.5%	0.8%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	7	0.0%	0.0%	0.0%	0.1%	0.5%	4.7%	22.0%	44.4%	21.4%	6.0%	0.7%	0.1%	0.0%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%
	8	0.0%	0.0%	0.0%	0.3%	0.5%	1.5%	8.9%	22.8%	40.0%	19.6%	5.7%	0.4%	0.0%	0.1%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%
	9	0.0%	0.0%	0.1%	0.3%	0.9%	1.4%	2.5%	12.0%	25.5%	32.8%	18.3%	4.5%	0.9%	0.3%	0.3%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%
	10	0.0%	0.0%	0.0%	0.2%	0.1%	0.6%	1.8%	1.9%	8.2%	30.4%	38.6%	13.1%	4.3%	0.4%	0.3%	0.0%	0.0%	0.2%	0.0%	0.0%	0.0%
	11	0.0%	0.0%	0.3%	0.0%	0.9%	0.0%	0.4%	1.5%	4.1%	14.3%	35.2%	25.9%	14.7%	1.9%	0.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	12	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.7%	0.9%	9.4%	8.7%	29.7%	32.8%	14.5%	1.7%	1.2%	0.3%	0.0%	0.0%	0.0%	0.0%
	13	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	7.1%	1.7%	4.9%	8.6%	13.2%	25.1%	19.5%	18.7%	1.3%	0.0%	0.0%	0.0%	0.0%	0.0%
	14	0.0%	0.0%	0.0%	2.6%	0.0%	0.0%	0.1%	0.1%	2.1%	8.0%	0.0%	12.2%	12.9%	19.5%	32.6%	7.9%	2.1%	0.0%	0.0%	0.0%	0.1%
	15	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	3.4%	0.1%	0.0%	4.3%	2.7%	2.3%	7.7%	35.3%	18.9%	16.3%	4.0%	5.0%	0.0%	0.1%
	16	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	3.0%	33.3%	41.0%	4.9%	1.8%	15.8%	0.0%
	17	0.0%	0.0%	0.0%	0.0%	0.0%	0.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.4%	0.0%	0.0%	21.6%	18.6%	17.3%	41.8%	0.0%	0.0%	0.0%
	18	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.7%	0.0%	0.0%	0.0%	0.7%	0.0%	52.4%	0.0%	0.0%	0.0%	46.2%	0.0%
	19	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.1%	0.0%	0.0%	0.0%	21.1%	0.0%	27.5%	0.0%	21.1%	28.2%
	20	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.4%	0.0%	0.0%	0.0%	9.1%	90.5%

Table 33: Markov matrix for the 4400th hour of the year. Each cell gives the probability that at the hour H+1 a certain wind speed will be reached, given a specified wind speed at H

Appendix C
Additional tables of the distribution of imbalance costs and remunerations

This appendix offers additional tables with average values and occurrences of the imbalance costs and remunerations for the situations combining system imbalance and BRP imbalance. They are based on the values calculated in section 5.3.4.

Each table represents the combination of one specific country and demand profile. The installed wind power and wind speed profile are the parameters in each table. Tables are given for the four demand profiles applied to the Belgian imbalance tariff design and for the demand profile of *Day 1*, applied to the four different countries' imbalance tariff designs. Each time the average tariffs and occurrences are given.

Each combination of system imbalance and BRP imbalance received a colour code for easy visualization. The **legend** of this colour code is the following:

- Positive system imbalance and positive BRP imbalance
- Negative system imbalance and positive BRP imbalance
- Positive system imbalance and negative BRP imbalance
- Negative system imbalance and negative BRP imbalance

		Windday								
		A	B	C	D		A	B	C	D
Installed wind power [MW]	500	21	21	21	21		99	98	103	96
	1000	21	21	21	21		99	98	103	95
	1500	21	21	21	21		99	98	104	94
	2000	21	21	21	21		99	98	105	93
	500	114	115	101	115		153	154	149	154
	1000	114	116	102	114		154	156	150	156
	1500	114	116	103	113		154	158	151	157
	2000	114	117	104	112		155	160	152	159

Table 34: Average cost (in €) and remuneration values for the Belgian imbalance tariff design and demand profile of Day 1. For increasing levels of installed wind power and the four different wind speed profiles.

Installed wind power [MW]		Windday							
		A	B	C	D	A	B	C	D
	500	23%	23%	31%	23%	30%	27%	44%	29%
	1000	23%	25%	32%	25%	30%	25%	43%	27%
	1500	24%	27%	33%	27%	29%	23%	42%	25%
	2000	25%	29%	33%	29%	28%	21%	41%	23%
	500	17%	18%	10%	17%	30%	33%	16%	31%
	1000	16%	16%	9%	15%	31%	35%	16%	33%
	1500	15%	14%	9%	14%	32%	37%	16%	34%
	2000	13%	12%	9%	12%	34%	38%	17%	36%

Table 35: Average occurrences for the Belgian imbalance tariff design and demand profile of Day 1. For increasing levels of installed wind power and the four different wind speed profiles.

		Windday								
		A	B	C	D		A	B	C	D
Installed wind power [MW]	500	11	11	11	11		50	49	52	50
	1000	11	11	11	11		50	49	52	49
	1500	11	11	11	11		50	49	52	49
	2000	11	11	11	11		51	49	52	49
	500	56	57	49	56		138	140	136	139
	1000	57	57	48	56		139	142	138	141
	1500	57	57	49	55		141	146	140	144
	2000	57	57	48	54		143	148	140	147

Table 36: Average cost (in €) and remuneration values for the Belgian imbalance tariff design and demand profile of Day 2. For increasing levels of installed wind power and the four different wind speed profiles.

		Windday								
		A	B	C	D		A	B	C	D
Installed wind power [MW]	500	22%	22%	31%	23%		31%	28%	44%	29%
	1000	23%	25%	32%	25%		30%	25%	43%	27%
	1500	24%	27%	33%	27%		29%	23%	42%	26%
	2000	25%	29%	33%	28%		28%	21%	42%	24%
	500	18%	18%	10%	17%		30%	32%	15%	30%
	1000	16%	16%	9%	16%		31%	34%	16%	32%
	1500	15%	14%	9%	14%		32%	36%	16%	34%
	2000	14%	12%	9%	12%		33%	38%	17%	35%

Table 37: Average occurrences for the Belgian imbalance tariff design and demand profile of Day 2. For increasing levels of installed wind power and the four different wind speed profiles.

		Windday								
		A	B	C	D		A	B	C	D
Installed wind power [MW]	500	8	8	8	8		37	37	40	36
	1000	8	8	8	8		37	37	40	35
	1500	8	8	8	8		37	37	40	35
	2000	8	8	8	8		37	37	41	34
	500	44	44	36	44		136	138	135	137
	1000	44	44	37	43		137	140	136	140
	1500	44	44	38	42		139	143	137	142
	2000	44	45	38	42		140	147	139	144

Table 38: Average cost (in €) and remuneration values for the Belgian imbalance tariff design and demand profile of Day 3. For increasing levels of installed wind power and the four different wind speed profiles.

		Windday								
		A	B	C	D		A	B	C	D
Installed wind power [MW]	500	23%	23%	31%	23%		30%	27%	44%	29%
	1000	24%	25%	32%	25%		30%	25%	43%	27%
	1500	24%	27%	33%	27%		29%	23%	42%	25%
	2000	25%	29%	33%	29%		28%	21%	41%	23%
	500	17%	18%	10%	17%		30%	33%	16%	31%
	1000	16%	15%	9%	15%		31%	35%	16%	33%
	1500	14%	14%	9%	14%		32%	37%	16%	34%
	2000	13%	12%	8%	12%		34%	38%	17%	36%

Table 39: Average occurrences for the Belgian imbalance tariff design and demand profile of Day 3. For increasing levels of installed wind power and the four different wind speed profiles.

		Windday								
		A	B	C	D		A	B	C	D
Installed wind power [MW]	500	4	4	4	4		20	20	20	20
	1000	4	4	4	4		20	20	20	20
	1500	4	4	4	4		20	20	21	20
	2000	4	4	4	4		20	20	21	19
	500	23	23	21	23		133	134	133	133
	1000	23	23	21	23		134	136	134	137
	1500	23	23	21	23		136	139	135	139
	2000	23	23	21	23		137	143	136	141

Table 40: Average cost (in €) and remuneration values for the Belgian imbalance tariff design and demand profile of Day 4. For increasing levels of installed wind power and the four different wind speed profiles.

		Windday								
		A	B	C	D		A	B	C	D
Installed wind power [MW]	500	22%	22%	31%	23%		30%	27%	44%	29%
	1000	23%	25%	32%	25%		30%	25%	43%	27%
	1500	24%	27%	33%	27%		29%	23%	42%	25%
	2000	25%	29%	33%	29%		28%	21%	41%	24%
	500	18%	18%	10%	18%		29%	32%	15%	30%
	1000	16%	16%	10%	16%		31%	35%	16%	32%
	1500	15%	14%	9%	14%		32%	37%	16%	34%
	2000	14%	12%	9%	12%		33%	38%	16%	36%

Table 41: Average occurrences for the Belgian imbalance tariff design and demand profile of Day 4. For increasing levels of installed wind power and the four different wind speed profiles.

Installed wind power [MW]	Windday A	B	C	D		A	B	C	D
500	21	21	21	21		137	135	137	136
1000	21	21	21	21		136	133	136	134
1500	21	21	21	21		135	129	136	131
2000	21	21	21	21		134	128	136	130
500	21	21	18	21		138	139	136	138
1000	21	21	18	21		139	140	137	139
1500	21	21	19	20		141	142	137	141
2000	21	21	19	20		142	144	138	143

Table 42: Average cost (in €) and remuneration values for the Dutch imbalance tariff design and demand profile of Day 1. For increasing levels of installed wind power and the four different wind speed profiles.

Installed wind power [MW]	Windday A	B	C	D		A	B	C	D
500	22%	22%	31%	23%		31%	28%	44%	29%
1000	23%	24%	31%	24%		30%	25%	43%	28%
1500	24%	26%	32%	26%		29%	23%	43%	26%
2000	24%	28%	33%	28%		28%	21%	42%	24%
500	18%	18%	10%	18%		30%	32%	15%	31%
1000	16%	16%	9%	16%		31%	35%	16%	32%
1500	15%	14%	9%	14%		32%	37%	16%	34%
2000	14%	12%	9%	12%		34%	39%	17%	36%

Table 43: Average occurrences for the Dutch imbalance tariff design and demand profile of Day 1. For increasing levels of installed wind power and the four different wind speed profiles.

Installed wind power [MW]	Windday							
	A	B	C	D	A	B	C	D
500	20	20	20	20	107	106	111	104
1000	20	20	20	20	107	106	112	103
1500	20	20	20	20	107	106	113	101
2000	20	20	20	20	107	106	114	100
500	106	107	93	107	169	169	166	169
1000	106	108	94	106	170	170	166	169
1500	106	108	95	105	171	169	166	169
2000	107	109	96	104	171	170	166	169

Table 44: Average cost (in €) and remuneration values for the French imbalance tariff design and demand profile of Day 1. For increasing levels of installed wind power and the four different wind speed profiles.

Installed wind power [MW]	Windday							
	A	B	C	D	A	B	C	D
500	22%	22%	31%	23%	31%	28%	44%	29%
1000	23%	25%	32%	25%	30%	25%	43%	27%
1500	24%	27%	33%	27%	29%	23%	42%	25%
2000	25%	29%	33%	28%	28%	21%	42%	24%
500	18%	18%	10%	18%	29%	32%	15%	30%
1000	16%	16%	9%	16%	30%	34%	16%	32%
1500	15%	14%	9%	14%	32%	36%	16%	34%
2000	14%	12%	9%	12%	33%	38%	16%	36%

Table 45: Average occurrences for the French imbalance tariff design and demand profile of Day 1. For increasing levels of installed wind power and the four different wind speed profiles.

Installed wind power [MW]		Windday A	B	C	D	A	B	C	D
	500	93	93	96	93	107	106	112	104
	1000	93	92	95	93	107	106	112	103
	1500	93	92	94	94	107	106	113	102
	2000	93	92	94	95	107	106	114	100
	500	106	107	93	107	126	126	115	127
	1000	106	108	94	106	126	126	115	128
	1500	106	109	96	105	126	126	114	128
	2000	107	109	96	104	126	126	114	128

Table 46: Average cost (in €) and remuneration values for the Spanish imbalance tariff design and demand profile of Day 1. For increasing levels of installed wind power and the four different wind speed profiles.

Installed wind power [MW]		Windday A	B	C	D	A	B	C	D
	500	22%	22%	31%	23%	31%	28%	44%	30%
	1000	23%	25%	32%	25%	30%	26%	43%	28%
	1500	24%	27%	33%	27%	29%	23%	42%	26%
	2000	25%	29%	33%	29%	29%	21%	42%	24%
	500	18%	18%	10%	18%	29%	32%	15%	30%
	1000	16%	16%	9%	16%	30%	34%	16%	32%
	1500	15%	14%	9%	14%	32%	36%	16%	33%
	2000	14%	12%	9%	12%	33%	38%	17%	35%

Table 47: Average occurrences for the Spanish imbalance tariff design and demand profile of Day 1. For increasing levels of installed wind power and the four different wind speed profiles.

Appendix D
Additional figures for the determination of the capacity credit through the allowed increase in Peak Load Carrying Capability (PLCC)

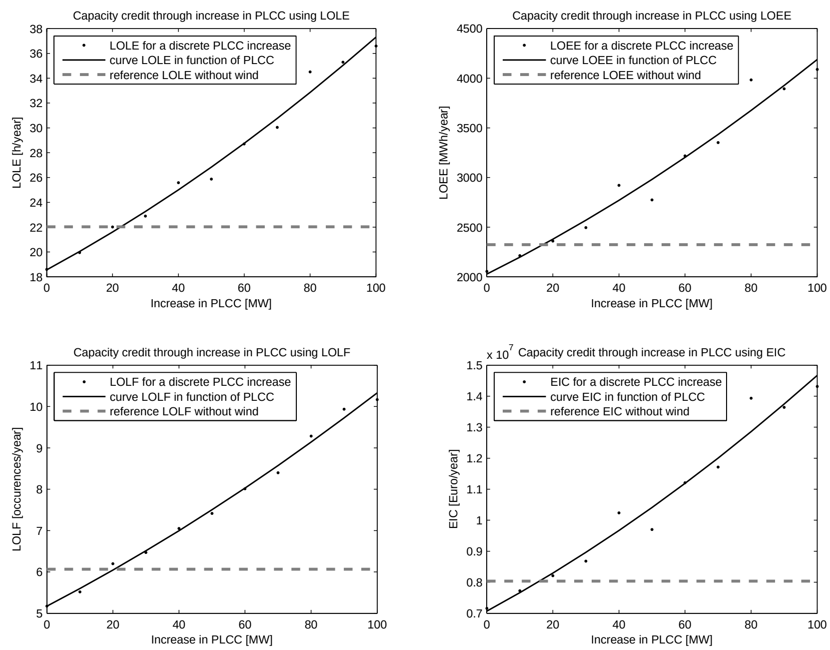

Figure 55: LOLE, LOEE, LOLF and EIC indices for increasing amounts of PLCC with an installed wind power capacity of 100 MW, in relation to the reference adequacy of the situation before the wind power introduction in the system.

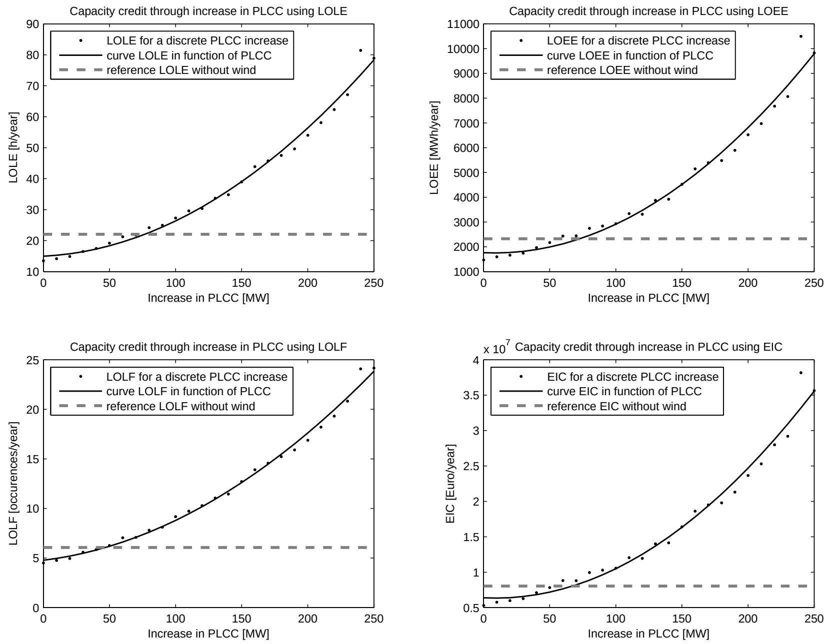

Figure 56: LOLE, LOEE, LOLF and EIC indices for increasing amounts of PLCC with an installed wind power capacity of 400 MW, in relation to the reference adequacy of the situation before the wind power introduction in the system.

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List of publications

Status on June 17, 2009

Articles in journals with review

1. Luickx, P.J., Delarue, E.D., D'haeseleer, W.D. 2009. Impact of large amounts of wind power on the operation of an electricity generation system: Belgian case study. Submitted for publication in Renewable and Sustainable Energy Reviews.

2. Luickx, P.J., Souto Perez, P., Driesen, J., D'haeseleer, W.D. 2009. Imbalance tariff systems in European countries and the cost effect of wind power. Submitted for publication in Energy Policy.

3. Luickx, P.J., Delarue, E.D., D'haeseleer, W.D. 2009. The examination of different energy storage methods for wind power integration. Submitted for publication in Renewable Energy.

4. Delarue, E.D., Luickx, P.J., D'haeseleer, W.D. 2009. The actual effect of wind power on overall electricity generation costs and CO2 emissions. Energy Conversion and Management. 50(6), 1450-1456

5. Luickx, P.J., Delarue, E.D., D'haeseleer, W.D. 2008. Effect of the Generation Mix on Wind Power Introduction. Accepted for publication in IET Renewable Power Generation, December 2008

6. Luickx, P.J., Delarue, E.D., D'haeseleer, W.D. 2008. Considerations on the backup of wind power: Operational backup. Applied Energy. 85(9), 787-799

7. Luickx, P.J., Helsen, L.M., D'haeseleer, W.D. 2008. Influence of massive heat-pump introduction on the electricity-generation mix and the GHG effect: Comparison between Belgium, France, Germany and The Netherlands. Renewable and Sustainable Energy Reviews. 12(8), 2140-2158

8. Luickx, P.J., Peeters, L.F., Helsen, L.M., D'haeseleer, W.D. 2008. Influence of massive heat-pump introduction on the electricity-generation mix and the GHG effect - Belgian case study. International Journal of Energy Research. 32(1), 57-67

Symposia and conference contributions

9. Luickx, P.J., Vandamme, W., Souto Pérez, P., Driesen, J., D'haeseleer, W.D. 2009. Applying Markov chains for the determination of the capacity credit of wind power. 6th International Conference on the European Energy Market, Leuven, Belgium May 27 - 29, 2009.

10. Luickx, P.J. 2009. Windenergie en België. Verzoenbaar ? Seminar Energy Institute, Katholieke Universiteit Leuven, April 4 2009.

11. Luickx, P.J., Delarue, E.D., D'haeseleer, W.D. 2008. Energy Storage for Wind Power: The Defeat of Don Quijote? 3rd Strategic Energy Forum, Autoworld Brussel, December 16, 2008 (poster presentation)

12. Luickx, P.J., Delarue, E.D., D'haeseleer, W.D. 2008. The examination of different energy storage methods for wind power integration. GlobalWind 2008, Beijing, China October 29-31, 2008.

13. Luickx, P.J., Delarue, E.D., D'haeseleer, W.D. 2008. The Effect of the Generation Mix on Wind Power Introduction. European Wind Energy Conference 2008, Brussels, Belgium March 31 - April 3, 2008.

14. Delarue, E.D., Luickx, P.J., D'haeseleer, W.D. 2007. The effect of implementing wind power on overall electricity generation costs, CO2 emissions and reliability. Wind Power Shanghai 2007 conference, Shanghai, China November 1-3, 2007.

15. Luickx, P.J., D'haeseleer, W.D. 2007. Backup of Electricity From Wind Power: Operational Backup Methods Analysed. World Wind Energy Conference 2007, Mar del Plata, Buenos Aires, Argentina October 2-4, 2007.

16. Luickx, P.J., Delarue, E.D., D'haeseleer, W.D. 2007. Considerations on the backup of wind power, Operational Backup. YEEES Young Energy Engineers and Economists Seminar, Dresden, 11-12 April 2007.

17. Luickx, P.J., D'haeseleer, W.D. 2005. The PROMIX simulation tool: An exercise for the massive introduction of heat pumps and its influence on the electricity-generation mix and GHG emissions. Market modelling of the central Western European market. ETE Modelling Workshop. Leuven, 15-16 September 2005.

Reports

18. Luickx, P.J., D'haeseleer, W.D. 2008. WindBalance, Balancing wind energy in the grid: an overall, techno-economic and coordinated approach. Task 5: No network, 1 ARP. August 2008.

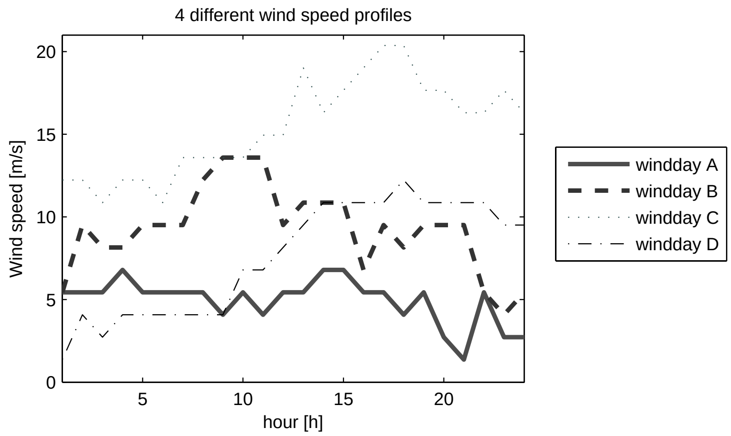
19. Luickx P.J., Pepermans G, D'haeseleer W.D. EUSUSTEL - European Sustainable Electricity; Comprehensive Analysis of Future European Demand and Generation of European Electricity and its Security of Supply. WORK PACKAGE 5: Most optimal solution for electricity provision. Subtask 5.1.ii: Considerations on 'shadow costs' such as back-up costs, risk premium etc. 2006

Book contributions

20. D'haeseleer W.D., Luickx P.J. La cogénération. In Sabonnadière J-C. Nouvelles technologies de l'énergie 2 : stockage et technologies à émission réduite. Lavoisier, 2007 (in French)

Wind speed and demand profiles

Following wind speed and demand profiles are used for analyses throughout the thesis. They are introduced in section 4.2.5. The 24-hour profiles are given below for easy reference.



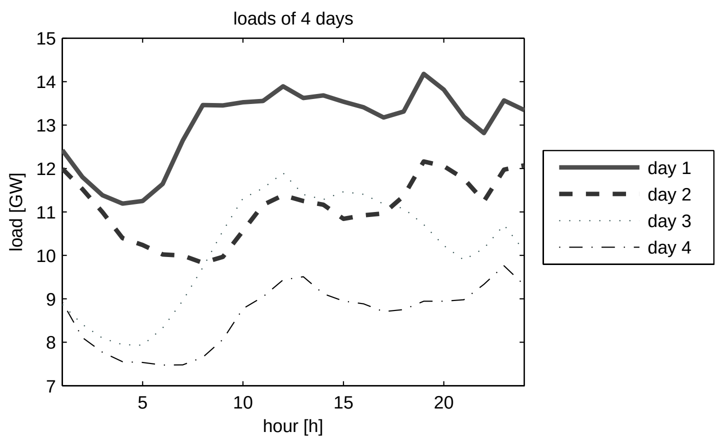


Figure 57: Wind speed and demand profiles used throughout the thesis.