



HAL
open science

**New dynamics in the electricity sector :
consumption-growth nexus, market structure and
renewable power**

Yuanjing Li

► **To cite this version:**

Yuanjing Li. New dynamics in the electricity sector : consumption-growth nexus, market structure and renewable power. Economics and Finance. Université Paris Dauphine - Paris IX, 2015. English. NNT : 2015PA090041 . tel-01266079

HAL Id: tel-01266079

<https://theses.hal.science/tel-01266079>

Submitted on 2 Feb 2016

HAL is a multi-disciplinary open access archive for the deposit and dissemination of scientific research documents, whether they are published or not. The documents may come from teaching and research institutions in France or abroad, or from public or private research centers.

L'archive ouverte pluridisciplinaire **HAL**, est destinée au dépôt et à la diffusion de documents scientifiques de niveau recherche, publiés ou non, émanant des établissements d'enseignement et de recherche français ou étrangers, des laboratoires publics ou privés.

UNIVERSITÉ PARIS-DAUPHINE

L'ÉCOLE DOCTORALE DE DAUPHINE

Laboratoire d'Economie (LEDa)

Centre de Géopolitique de l'Énergie et des Matières Premières (CGEMP)

THÈSE

POUR L'OBTENTION DU GRADE DE DOCTEUR EN SCIENCES ÉCONOMIQUES

Présentée par

Yuanjing Li

Sous la direction d'Anna Creti, professeur à l'Université Paris-Dauphine

**NEW DYNAMICS IN THE ELECTRICITY SECTOR :
CONSUMPTION-GROWTH NEXUS, MARKET STRUCTURE, AND
RENEWABLE POWER**

Thèse soutenue publiquement à l'Université Paris-Dauphine

le 10 novembre 2015

Devant le jury composé de :

| | | |
|--------------------------------|---------------------------------------------------------|------------|
| Mme Anna Creti | Professeur à l'Université Paris-Dauphine | Directrice |
| M. Frédéric Lantz | Professeur à l'IFP School | Rapporteur |
| Thomas-Olivier Léautier | Professeur à l'Université Toulouse 1 Capitole | |
| María Eugenia Sanin | Maître de conférences à Université d'Evry-Val-d'Essonne | |
| Rafał Weron | Professeur à Wrocław University of Technology | Rapporteur |

致我的父亲母亲

À Cyrille

Acknowledgements

As the old Chinese saying goes, a journey of a thousand miles begins with a single step. As for me, every step over the past three years has been built up here. This thesis could not have been done without the support of so many influential people.

First of all, I would like to express my deep gratitude to my advisor, Anna Creti, for her patient guidance and valuable critiques. Besides that, her enthusiasm and energy have influenced me as much as her scientific advice. I feel lucky to have met her in Barcelona, and I could not have asked for a better advisor.

Second, I am grateful to Fatih Karanfil for coauthoring two chapters of this thesis. Also, his expertise and generosity have made it possible to continue our collaboration on various topics out of my thesis. I would like to thank all people, who have contributed to improving this research work, in particular, Marie Bessec, Silvia Concettini, Marc Joëts, Jan Horst Keppler, Frédéric Lantz, Yannick Le Pen, Frédéric Loss, Scott Masten, Juan-Pablo Montero, Duc Khuong Nguyen, John Ney, Philippe Vassilopoulos, and Aleksandar Zaklan. My gratitude also goes to the Chaire European Electricity Markets Fondation Paris-Dauphine and its scientific committee.

I would like to offer my special thanks to the reviewers and jury members for their acceptance to be part of my defence and their time devoted to this work.

I am hugely indebted to my family in China for its continuous support and understanding. My gratitude also goes to my beloved Cyrille for his help with my French writing.

Finally, I extend my thanks to my friends and colleagues from Mapp Economics, Ipag Lab, Université Paris-Dauphine, and Université Paris-Nanterre. For those that I might have forgotten to mention here, you are surely not forgotten in my heart.

Contents

| | |
|--------------------------------------------------------------------------------------------|-----------|
| Introduction générale | 11 |
| Bibliography | 35 |
| 1 Electricity consumption and economic growth: Exploring panel-specific differences | 40 |
| 1.1 Introduction | 41 |
| 1.2 Methods | 46 |
| 1.2.1 Literature review | 46 |
| 1.2.2 Data | 48 |
| 1.3 Results | 56 |
| 1.3.1 Unit root and cointegration results | 56 |
| 1.3.2 Causality results | 58 |
| 1.4 Discussions | 60 |
| 1.5 Conclusions and policy implications | 65 |
| 1.5.1 Conclusions | 65 |
| 1.5.2 Policy implications | 66 |
| 1.5.3 Further research and caveats | 67 |
| Bibliography | 68 |
| Appendices | 74 |
| 2 Vertical structure and forward contracts | 85 |
| 2.1 Introduction | 86 |

| | | |
|----------|----------------------------------------------------------------------------------|------------|
| 2.2 | Literature review | 90 |
| 2.3 | Model setup | 93 |
| 2.4 | Analytical results | 96 |
| 2.4.1 | Spot market | 96 |
| 2.4.2 | Forward market | 97 |
| 2.4.3 | Retail market | 100 |
| 2.5 | Discussions | 104 |
| 2.5.1 | Impact of vertical integration | 104 |
| 2.5.2 | Conjectural variation | 107 |
| 2.6 | Numerical simulations | 108 |
| 2.7 | Conclusion | 111 |
| | Bibliography | 115 |
| | Appendices | 120 |
| 3 | Day-ahead short-term price and volatility dynamics with rising wind power | 129 |
| 3.1 | Introduction | 130 |
| 3.2 | Literature review | 133 |
| 3.3 | Market settings and fundamentals | 135 |
| 3.3.1 | The Nord Pool Spot and system price | 135 |
| 3.3.2 | Wind power in Denmark | 136 |
| 3.3.3 | Substitution between wind power and hydropower | 137 |
| 3.3.4 | The data | 139 |
| 3.4 | Methodology | 141 |
| 3.4.1 | Long-term and short-term seasonal components | 141 |
| 3.4.2 | Model specifications | 144 |
| 3.4.3 | Model evaluation and forecast accuracy | 147 |
| 3.5 | Empirical results and analyses | 148 |
| 3.5.1 | Estimation results of a conventional GARCH model | 148 |
| 3.5.2 | Asymmetric GARCH and heavy-tail error distribution | 148 |
| 3.5.3 | Discussions of estimation results | 152 |

| | | |
|----------|--------------------------------------------------------------------------------------|------------|
| 3.5.4 | Forecast performance | 154 |
| 3.6 | Conclusion | 156 |
| | Bibliography | 158 |
| | Appendices | 163 |
| 4 | Wind power integration: Wind up with continuous intraday electricity markets? | 174 |
| 4.1 | Introduction | 175 |
| 4.2 | Literature review | 178 |
| 4.3 | Market settings | 180 |
| 4.4 | Methods | 181 |
| 4.4.1 | Data sources | 181 |
| 4.4.2 | Data descriptions | 182 |
| 4.4.3 | Empirical methodology | 187 |
| 4.5 | Results | 190 |
| 4.6 | Discussions | 193 |
| 4.7 | Conclusion | 195 |
| | Bibliography | 201 |
| | Appendices | 205 |
| 5 | Conclusion générale | 209 |
| | Bibliography | 213 |

Introduction générale

Un nouveau paysage du secteur de l'électricité

La disponibilité continue et abordable de l'électricité est une condition nécessaire pour le bon fonctionnement d'une économie et plus généralement d'une société moderne. Au cours des dernières décennies, la nature des marchés électriques est devenue de plus en plus dynamique et vivante. Une persistante instabilité géopolitique, des modèles de marché obsolètes, et le réchauffement climatique sont autant de défis pour le secteur de l'électricité. Pour ces raisons, les marchés électriques ont été et continueront d'être sous le feu des projecteurs de nombreux débats politiques.

Prenant l'exemple de l'Union européenne (UE), son objectif pour l'année 2020 est : la réduction de 20% des émissions de gaz à effet de serre par rapport à 1990, une part de 20% d'énergies renouvelables dans la consommation finale d'énergie, et la réalisation de 20% des économies d'énergie par rapport à l'augmentation tendancielle. La stratégie pour atteindre cet objectif implique à la fois le contrôle de la consommation d'énergie et les extensions de réseaux (CE, 2010). Un rapport publié en 2014 (CE, 2014) a constaté que les prix de détail de l'électricité ont augmenté de 4% pour les consommateurs finals entre 2008 et 2012 tandis que les prix de gros de l'électricité ont diminué de façon significative au cours de la même période. Pour comprendre les tendances divergentes des prix de gros et de détail à travers les marchés de l'électricité de l'UE, la politique climatique et le soutien du gouvernement aux énergies renouvelables sont souvent pointés du doigt. Avec un objectif plus ambitieux à l'horizon 2050, l'UE prépare une transition vers une économie compétitive à faible intensité en carbone en réduisant ses émissions domestiques de 80% par rapport à 1990 (CE, 2011).

Assurer une fourniture ininterrompue de l'électricité, à un prix relativement compétitif, abordable pour tous les ménages et industriels, tout en atteignant les objectifs de promotion des énergies renouvelables relève presque de la quadrature du cercle. En effet, les inquiétudes au sujet de la résilience du système d'électricité de l'UE ont été soulevées par plusieurs aspects. Par exemple, la crise économique en 2008 a conduit à une révision fondamentale de la demande d'électricité. La part importante des importations de gaz rend le système vulnérable à un choc venu de l'extérieur. En outre, la conception du marché et le mécanisme du prix de gros, qui ont été mis en place il y a deux décennies, ne pouvait pas s'adapter à un développement rapide des énergies

renouvelables, alors que la concentration du marché est toujours restée élevée du côté de la production depuis la libéralisation des marchés de l'électricité. Ces préoccupations ont mis en doute l'adéquation même entre la conception actuelle du marché et la stratégie de décarbonisation. Par conséquent, un nouveau paysage de la croissance économique, de la compétitivité du marché, et de la transformation technologique de la structure de la production appellent à une intégration des cadres politiques différents.

L'UE souligne l'importance de la sécurité d'approvisionnement, la compétitivité et la durabilité dans le secteur de l'énergie. Ces trois défis rencontrés par le secteur de l'électricité ne se limitent pas à l'UE, mais aussi aux pays développés et en voie de développement. Pour comprendre les priorités des réformes et les objectifs à fixer, il faut identifier les questions essentielles concernant le secteur de l'électricité, en prenant en compte le fait que les pays ont des rythmes de croissance économique et des sensibilités aux chocs externes divergents. Depuis les années 1990, la plupart des pays dans les continents européen et américains ont procédé successivement à une libéralisation du secteur de l'énergie. Au cours de celle-ci, les monopoles historiques, qui étaient verticalement intégrés, ont été restructurés, et les marchés de gros de l'électricité ont été créés et ouverts à la concurrence. Il n'est pas surprenant que les nouveaux défis dans le secteur de l'énergie dans ces pays soient concentrés sur les questions de concurrence ainsi que les fluctuations et les incertitudes causées par une part croissante de production d'énergie renouvelable. Pour répondre à ces défis, des politiques de concurrence, de soutien aux énergies renouvelables, plus généralement des politiques climatiques sont maintenant engagées dans les marchés libéralisés de l'électricité. Toutefois, cela n'est certainement pas le cas dans la plupart des pays asiatiques et africains. Bien que certains d'entre eux aient cherché à adopter une législation en mettant en place une réforme de l'offre, ils sont encore loin d'avoir des marchés matures, à la fois en ce qui concerne la concurrence du gros et du détail. En particulier en Afrique sub-saharienne, des graves pénuries récurrentes causées par l'infrastructure électrique insuffisante sapent les efforts visant à parvenir à une croissance économique et une amélioration du niveau de vie (AIE, 2014). Dans ces pays, la priorité des politiques de réforme est de promouvoir l'accès essentiel à l'électricité, que ce soit par des investissements dans les infrastructures ou par l'intermédiaire des installations d'import et d'export, afin de permettre une couverture complète de la demande d'électricité générée par la croissance économique. Il apparaît

donc clairement que, pour la majorité des pays émergents, l'objectif de la conservation de l'énergie et son lien avec la croissance économique est primordial.

Le passage d'une stratégie politique à une réalisation des trois objectifs mentionnés ci-dessus dans le secteur de l'électricité peut être résumé dans le schéma de la Fig. 1. La dynamique de l'industrie des services publics héritée des évolutions de demande d'électricité, des structures de marché, et des actions de l'énergie renouvelable, appelle de nouvelles orientations dans la recherche sur l'économie de l'énergie. **L'objectif de cette thèse est d'étudier les changements en cours et leurs impacts sur les marchés de l'électricité à partir de la perspective de la demande d'électricité et la performance économique globale, des configurations structurelles du marché, et d'une transition vers des sources d'énergie renouvelables.**

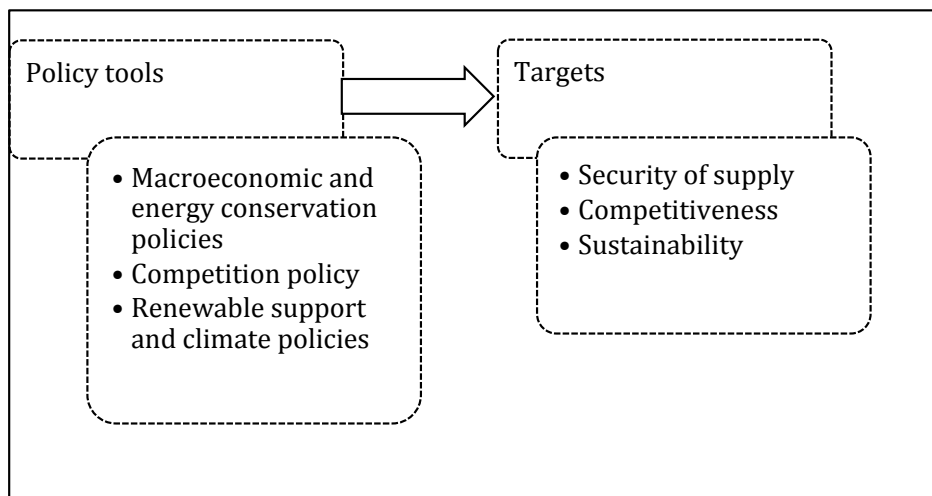


Figure 1 – Les dimensions des outils et les objectifs politiques. Réalisation de l'auteur.

Vue d'ensemble des relations entre la demande d'électricité et une économie

L'électricité est un facteur essentiel pour les activités industrielles, commerciales et résidentielles. Comme la quantité de consommation d'électricité peut être utilisée pour mesurer sa demande, sa consommation est souvent considérée comme une force majeure

pour stimuler la croissance économique. Inversement, la croissance économique a aussi une grande influence sur l'évolution de la demande d'électricité (Payne, 2010). À la lumière de ces liens vitaux qui peuvent exister entre la demande d'électricité et les activités économiques, et depuis les travaux pionniers de Kraft et Kraft (1978), des efforts importants ont été faits pour déterminer l'existence et le sens de la relation de causalité entre la consommation d'électricité et la croissance économique agrégée. De manière générale, les liens entre la demande électrique et la croissance économique peuvent être classés en quatre hypothèses vérifiables:

- *L'hypothèse de croissance* suppose une causalité unidirectionnelle allant de la demande d'électricité à la croissance économique. Il suggère que l'énergie, en tant que facteur de production complémentaire de capital et de travail, peut influencer directement ou indirectement la croissance économique. Dans ce contexte, une politique de conservation de l'énergie, qui réduit la consommation d'électricité, aura un impact négatif sur la croissance économique.
- *L'hypothèse de conservation* propose une causalité unidirectionnelle allant de la croissance économique à la demande d'électricité de sorte qu'elle implique une économie moins dépendante de l'énergie. Par conséquent, une augmentation du produit intérieur brut réel (PIB) va provoquer une augmentation de la consommation d'électricité, et une réduction de la consommation ne peut pas entraver la croissance économique.
- *L'hypothèse de retour* précise qu'il existe une causalité bidirectionnelle entre la consommation d'électricité et la croissance économique. Elle met l'accent sur l'interdépendance entre elles. Les deux sont déterminées conjointement et affectées par l'énergie et les politiques économiques en même temps.
- *L'hypothèse de neutralité* indique une absence de relation causale entre la demande et la performance économique, ce qui signifie que les politiques énergétiques qu'elles soient conservatrices ou expansives en matière de consommation électrique n'ont aucun effet sur la croissance économique.

Les Fig. 2 et 3 illustrent, à travers une comparaison dans le monde entier, les niveaux de consommation d'électricité par habitant et le PIB par habitant en 2010. Comme

prévu, une cohérence entre eux peut être observée, qui est que les pays ayant un PIB par habitant élevé ont également une demande d'électricité élevée, tandis que les pays sous-développés ont souvent une faible consommation d'électricité par habitant.

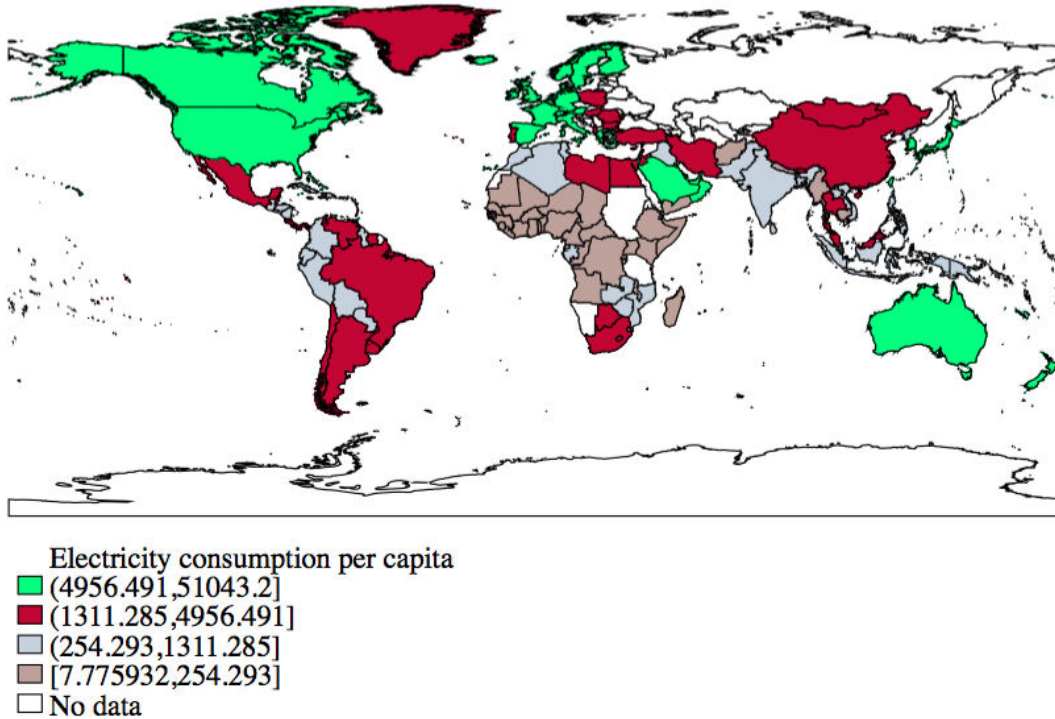


Figure 2 – la consommation d'électricité par habitant en 2010 par pays (kWh par habitant). Source: EIA. Réalisation de l'auteur.

En dépit du fait que des corrélations peuvent être détectées, en ligne avec les quatre scénarios précités, les résultats contradictoires des travaux antérieurs qui ont étudié le lien entre la consommation d'électricité-croissance, basés sur une sélection diversifiée de pays, ont échoué à parvenir à un consensus. Par exemple, Chen et al. (2007) a appuyé l'affirmation selon laquelle la croissance économique stimule la demande d'électricité dans les pays d'Asie du Sud, mais Yoo (2006) a trouvé des preuves de causalité bidirectionnelle dans la même région. En outre, Narayan Prasad (2008) a révélé la preuve d'une absence de lien causal entre la consommation d'électricité et la croissance économique dans la plupart des pays européens. En revanche, Ciarreta et Zarraga (2010) ont préconisé le maintien du niveau de la consommation d'électricité en Europe car celle-ci

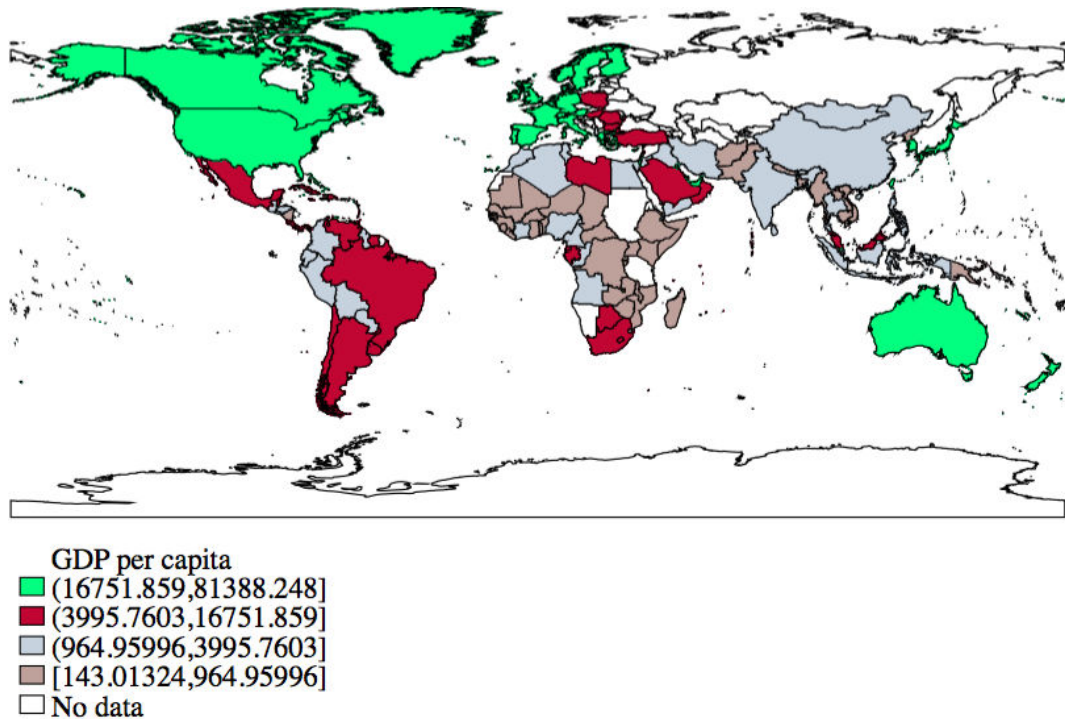


Figure 3 – PIB par habitant en 2010 par pays (\$ à prix constants de 2005). Source: CNUCED. Réalisation de l’auteur.

favorise la croissance du PIB. En conséquence, les recherches antérieures sur la détermination de la direction de liens de causalité entre la consommation d’énergie et la performance économique, bien assez riches, sont néanmoins insuffisantes pour fournir des preuves fiables ou pour tenir compte des hétérogénéités des pays eu égard aux risques d’approvisionnement et aux expansions urbaines.

Il convient d’ajouter que le lien entre la croissance économique et la demande d’électricité pourrait être influencé par d’autres facteurs : proportions de la population urbaine et vulnérabilité aux risques externes. Comme indiqué par Gnansounou (2008), un indicateur de premier plan est que le commerce d’électricité transfrontalier peut impliquer la vulnérabilité de l’approvisionnement d’un pays et de son degré d’intégration du marché. En effet, les connexions internationales d’un marché de l’électricité ne sont pas seulement une étape essentielle vers une intégration du marché à grande échelle, mais aussi, au niveau agrégé, ils peuvent sauvegarder l’approvisionnement en électricité

dans un marché commun et à leurs tours soutenir l'économie d'un pays. D'autre part, parmi d'autres facteurs qui peuvent influencer sur le lien entre la consommation-croissance, l'urbanisation rapide associée à la demande croissante d'électricité est en train de transformer la structure de la consommation d'énergie dans de nombreux pays émergents. Pour cette raison, il faut prendre en compte le rôle important de ce facteur, en particulier dans les pays en voie de développement. Basés sur l'expérience passée, les pays asiatiques, comme le Japon et la République de Corée, ont historiquement bénéficié de l'urbanisation rapide à intensifier les investissements dans l'infrastructure. En 2014, la consommation par habitant d'électricité de la Chine a été multipliée par quatre en 14 ans, et cette croissance explosive de la demande d'énergie a été accompagnée par une expansion massive de la population urbaine. Par contre, la situation est différente en Afrique subsaharienne. La population urbaine de cette région est actuellement seulement de 36% et n'est projetée d'atteindre 50% qu'en 2030 (Banque mondiale, 2015). L'expansion urbaine lente alliée au manque d'infrastructures d'alimentation exacerbe les conditions économiques de cette région. En fait, l'hétérogénéité entre les pays n'a pas été suffisamment considérée dans les travaux précédents. Par conséquent, une enquête approfondie complètera la recherche existante sur le sens de la causalité entre la demande d'électricité et la performance d'une économie.

Restructuration, concurrence et marchés verticaux

L'industrie de l'électricité a été historiquement sélectionnée par des entités intégrées verticalement car elle a été pensée comme une industrie de monopole naturel. En tant que premier pays au monde à mettre en œuvre une réforme globale, le Chili a commencé à restructurer son monopole public de l'état en 1982, quatre ans plus tôt que la réorganisation du secteur de l'électricité en Angleterre et au Pays de Galles. La réforme a conduit à une séparation des activités de transmission et distribution des activités de génération et détaillant, à une privatisation des actifs de production, et à une commercialisation du commerce de détail. Dans les années suivantes, l'expérience chilienne entraîna une vague de réformes à travers le monde. Aux États-Unis, les réformes ont été introduites plus rapidement en Californie et dans le Nord-Est, suivis par d'autres états, afin de promouvoir la concurrence et de nouveaux modèles de marché (Joskow,

1997). Au Royaume-Uni, la nouvelle structure a été introduite en 1990, et les actifs de l'opérateur historique «Central Electricity Generating Board» ont été transférés à quatre sociétés remplaçantes: une concurrence duopolistique a été instaurée entre «National Power» et «PowerGen» dans la production d'énergie des combustibles fossiles; les centrales nucléaires de production ont été transférées à «Nuclear Electric» ; le système de transmission a été repris par «National Grid Company». À la suite de l'initiative du Royaume-Uni, d'autres pays européens ont également lancé progressivement les réformes dans le secteur de l'énergie. Plusieurs grands marchés européens de gros de l'électricité ont été mis en place depuis lors. Pour aller plus loin, la Commission européenne a mis en place la fin des années 1990 un objectif d'un marché intérieur de l'énergie pour l'électricité, fixant un cadre réglementaire et des règles communes pour faciliter un marché intérieur au niveau européen, y compris l'accès des tiers réglementé, le dégroupage et la libéralisation de la fourniture.

Malgré la création réussie du marché de gros, la libéralisation n'a manifestement pas atteint l'objectif de concurrence attendu. Au Royaume-Uni, l'émergence de seulement deux producteurs conduit à un pouvoir de marché significatif qui se maintient pendant de nombreuses années (Green et Newbery, 1992; Wolfram, 1999). En conséquence, les questions de concurrence, arrivant avec la libéralisation du secteur de l'électricité, ont commencé à attirer l'attention et à faire débat.

Comparé à d'autres produits énergétiques, comme le pétrole ou le gaz, l'électricité présente une variété de caractéristiques qui font que ses marchés sont plus vulnérables à l'exercice du pouvoir de marché que les autres marchés de l'énergie (Borenstein, 2000). Commencant par la demande d'électricité, elle est très variable d'heure en heure pendant la journée et a une forte saisonnalité. Ces caractéristiques de la demande d'électricité peuvent être illustrées aux Fig. 4 et 5. En prenant comme exemple la consommation française en 2014 (la Fig. 4), le niveau de consommation est élevé en hiver et faible en été. Dans la Fig. 5, une différence significative dans la demande d'électricité entre une journée de travail et un week-end peut être facilement notée. En plus de cela, on observe que les heures de pointe de la demande d'électricité sont de 8h-10h et de 18h-20h, alors que les heures de l'après-midi et de la nuit sont généralement des heures de faible demande. Outre la variabilité de la demande d'électricité, il est également important de mentionner que la demande à court terme est presque inélastique en raison

de l'inflexibilité de nombreuses activités économiques et des tarifs de consommation finale.

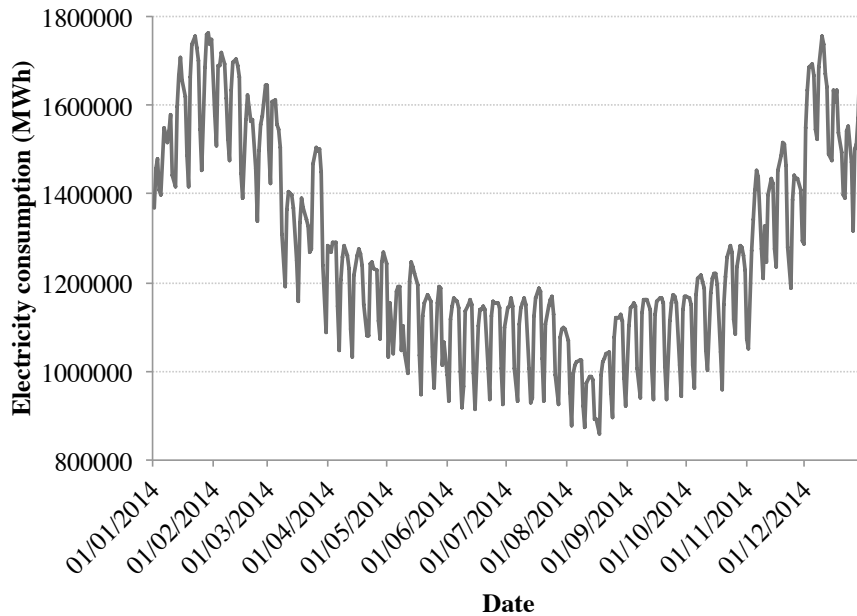


Figure 4 – La consommation quotidienne d’électricité en 2014 en France. Source: RTE. Réalisation de l’auteur.

Jusqu’à présent, l’électricité ne peut pas être stocké à un coût compétitif,¹ exigeant que la demande doit être équilibrée avec l’offre instantanément et à chaque emplacement sur le réseau. Des déséquilibres non résolus peuvent causer une restriction de la disponibilité de l’électricité dans une certaine région (une baisse de tension), ou une perturbation plus grave dans le système de l’électricité (une panne). Par conséquent, un opérateur de transmission du système est nécessaire pour maintenir l’équilibre du système électrique. Bien que l’introduction de la concurrence dans le marché de détail et des réponses sensibles aux prix de la consommation finale peut atténuer le problème de pouvoir de marché en amont (Joskow et Tirole, 2006), une capacité de réserve

¹Avec le progrès technologique, stockage de l’électricité a été rendue possible. Systèmes de stockage comprennent des batteries électriques à l’état solide, les batteries de débit, thermiques, par pompage, etc. Pour plus de détails, voir la CEI (2015). Malgré un avenir prometteur, toutes les technologies de stockage ne sont pas encore compétitives en terme de coûts, et leur déploiement est très limité.

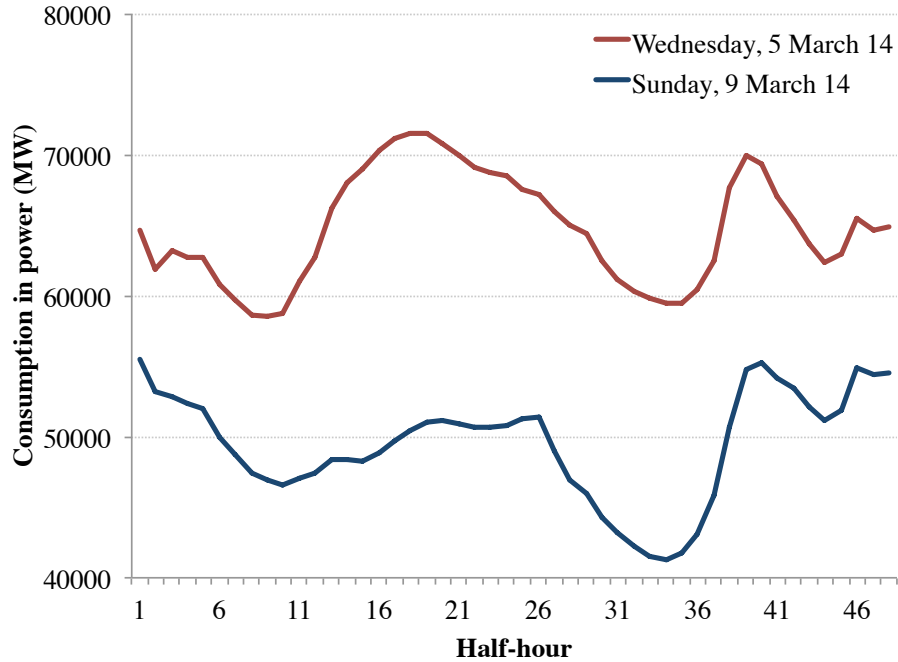


Figure 5 – Consommation semi-horaire d’électricité en France sur deux jours représentatifs. Source: RTE. Réalisation de l’auteur.

supplémentaire est presque toujours nécessaire afin de compenser les déséquilibres du système à proximité ou en temps réel. En outre, même s’il est reconnu que l’électricité est un bien homogène, ses technologies de production diffèrent largement en fonction des coûts d’investissement, des coûts marginaux, des coûts de rampe, et du temps de démarrage nécessaire.

En principe, la conception d’un marché de l’électricité en amont diverge en deux formes: un marché de gros, et un marché bilatéral. Le premier modèle de marché est un modèle standard pour la majorité des marchés de l’électricité (i.e. marchés day-ahead), auquel les producteurs soumettent leur planning de production tandis que les distributeurs et les détaillants soumettent la consommation prévisionnelle, généralement un jour avant le jour de l’opération. En conséquence, un prix d’équilibre est déterminé par la source de génération la plus chère possible, tout en égalisant l’offre et la demande. En d’autres termes, un producteur vend une quantité en fonction de son enchère au prix spot, qui est fixé par la loi de l’offre et de la demande sur le marché de gros. Par

rapport à un marché de gros dans lequel les offres sont centralisées par une bourse de l'électricité, un marché bilatéral fournit une plate-forme permettant aux acheteurs et aux vendeurs de négocier directement. Le transfert le plus important d'un modèle de gros à un modèle bilatéral a été fait par l'Angleterre en 2001. La mise en œuvre des «New Electricity Trading Arrangements» (NETA) a été une étape importante dans la restructuration du marché de l'électricité britannique, en remplaçant le marché de gros par le marché bilatéral.

Bien qu'il existe une controverse sur l'effet concurrentiel des deux conceptions du marché, les prix spot ont bien diminués après l'introduction de NETA (Fabra et Toro, 2003; Giuletta et al, 2010). Ainsi, il a été démontré que la conception du marché bilatéral est plus efficace pour atténuer le pouvoir de marché des producteurs par rapport à celle du marché de gros. Cependant, en examinant les stratégies d'appel d'offres, de nombreux chercheurs ont montré que, indépendamment de la conception du marché, les producteurs ont une forte incitation à exercer un pouvoir de marché et ceci est particulièrement vrai pour les producteurs pivots, qui ont la capacité de remplir la dernière unité de la demande (Crawford et al., 2007; Fabra et al, 2006; Fehr et Harbord, 1993; Garcia-Diaz et Pedro, 2003). Sur ce compte, des contrats à terme sont apparus comme un outil important pour atténuer le pouvoir de marché des producteurs, et la relation verticale entre les producteurs et les détaillants a également été mise en lumière.

Les producteurs et les détaillants d'électricité peuvent établir une relation soit par des contrats à terme (ie contrats à long terme), soit par l'intégration verticale (c'est-à-dire fusions). D'après les modèles industriels académiques, une éviction anticoncurrentielle peut se produire lorsque l'entreprise en amont, verticalement intégrée et dominante, refuse l'accès d'un facteur essentiel à d'autres entreprises individuelles en aval avec l'intention de monopoliser le marché en aval (Hart et al., 1990; Rey et Tirole, 2006). Suite à une logique similaire, un contrat vertical qui implique l'exclusivité peut empêcher l'entrée (Aghion et Bolton, 1987). Pour cette raison, les décideurs politiques ont été initialement opposés à l'utilisation de contrats à terme, qui ont été considérés comme un outil anti-concurrentiel qui entravent probablement l'entrée dans le marché de la génération. Cependant, le travail séminal de Allaz et Vila (1993) a montré que, en signant des contrats à terme, les fournisseurs en concurrence se comportent plus agressivement sur le marché spot. Un tel comportement stratégique dans la négociation des

contrats à terme met les producteurs dans un dilemme du prisonnier. En conséquence, le prix au comptant est réduit et l'efficacité est améliorée lorsque tous les générateurs le font. Le résultat de Allaz et Vila a inspiré de vastes travaux successifs qui se sont intéressés à l'effet des contrats à terme sur la concurrence du marché au comptant. Dans un modèle basé sur une fonction de l'offre (Klemperer et Meyer, 1989), Newbery (1998) a noté que les contrats peuvent en effet empêcher l'entrée, mais, contrairement à Aghion et Bolton (1987), la dissuasion ne se produit que quand il est efficace de le faire. En conséquence, l'échange de contrats à terme améliore l'efficacité du système car seuls les entrants inefficaces sont bloqués. En outre, de nombreuses études empiriques ont souligné le degré d'engagements verticaux entre entreprises génératrices et de détail, ce qui peut être décisif pour l'aspect concurrentiel des marchés au comptant (Bushnell, 2007; Wolak, 2007). Par la suite, il est devenu largement accepté d'envisager des contrats à terme comme un dispositif d'atténuation du pouvoir de marché, mais les avantages des contrats à terme ne peuvent pas être pleinement réalisés en présence de collusion (Powell, 1993), d'aversion au risque des détaillants (Creti et al., 2005), ou de concurrence parmi les détaillants (Green, 2004).

De manière générale, les acteurs peuvent avoir deux motifs pour vendre de l'électricité sous forme de contrats à terme avant l'ouverture du marché au comptant: la couverture et le trading stratégique. D'une part, l'incertitude de la demande résultant des fluctuations des prix spot fournit une justification pour les participants au marché de couvrir leurs risques. D'autre part, du point de vue de la concurrence, des résultats très probants ont émergé : l'utilisation de contrats à terme a favorisé la concurrence, élargit la production globale, et poussé les prix au comptant au plus proche des coûts marginaux lorsque les entreprises oligopolistiques étaient non-coopératives en sens de la compétition de Cournot. La littérature précédente a mis en avant ces deux points mais a négligé de différencier clairement les contrats à terme de l'intégration verticale. Vraisemblablement, ils ont souvent été considérés comme des substituts parfaits ou partiels, et leurs impacts sur la concurrence ont été considérés comme similaires, puisque les deux créent une liaison verticale entre les producteurs et les détaillants. En outre, la possibilité d'éviction anticoncurrentielle n'est pas une préoccupation dans les marchés de gros libéralisés d'électricité. La raison en est que, de par la conception du marché, aucun producteur ne peut vendre de l'électricité à un détaillant en particulier, car tous

les producteurs sont obligés de passer par le mécanisme de gros centralisé.² Cet argument justifie la poursuite de l'effet uniforme attendu de l'intégration verticale et des contrats à terme sur la concurrence. Malgré la validité de la justification économique ci-dessus, il est important de noter que la différence des effets sur la concurrence entre l'intégration verticale et les contrats à terme peut provenir du fait que les profits des détaillants dépendent des profits des producteurs. Plus précisément, un détaillant intégré peut internaliser les profits partiellement ou totalement en amont tandis qu'un détaillant indépendant ne peut pas le faire, même s'ils pourraient tous souscrire aux contrats à terme avec les producteurs. En attendant de partager les bénéfices en amont, un détaillant intégré serait intéressé par la hausse des prix au comptant en réduisant sa quantité contractée. En d'autres termes, l'émergence d'un système de récompense dépendante entre les producteurs et les détaillants est susceptible de diminuer l'efficacité du marché et d'augmenter le pouvoir de marché vertical. Par conséquent, il vaut la peine d'étudier les effets sur la concurrence des contrats à terme quand ils interagissent avec une intégration verticale.

Un facteur disruptif: l'énergie renouvelable intermittente

Avec une prise de conscience mondiale des effets néfastes des gaz à effet de serre (GES) sur l'environnement, le développement de technologies de production d'énergie renouvelable, comme l'éolien et le photovoltaïque (PV), prend une part importante dans la transition des combustibles fossiles vers l'énergie verte et donc à réduire les émissions de carbone. Dans ce contexte, afin de promouvoir la production d'électricité à partir de l'énergie verte, des politiques de tarifs garantis pour rémunérer les coûts élevés des investissements ont été mises en place au début. En Europe, depuis 2000, la priorité est de réduire l'impact environnemental de l'utilisation de combustibles fossiles, contrairement aux années 1990, durant lesquelles la priorité était à la libéralisation et la déréglementation du marché afin d'atteindre l'efficacité concurrentielle et d'augmenter

²Il pourrait y avoir des marchés intra-journaliers ou équilibrage après la négociation sur le marché day-ahead, mais le marché day-ahead restera toujours le marché le plus important en termes de quantité d'échange et d'interactions avec les contrats à terme.

le bien-être des consommateurs. Le lourd fardeau des politiques de soutien aux énergies renouvelables, reflétés dans les prix de détail de l'électricité, est en grande partie portée par les consommateurs, mais en plus, une certaine quantité de pouvoir de marché est perçue comme acceptable, car elle crée des revenus pour les producteurs et donc incite à investir dans les nouvelles technologies (Twomey et Neuhoff, 2010).

La situation actuelle des capacités cumulées en Europe pour l'éolien et le photovoltaïque est décrite, respectivement, dans les Fig. 6 et 7. Sans aucun doute, l'Allemagne est le premier pays dans les deux investissements des éoliennes et des solaires grâce à son régime de soutien aux renouvelables très efficace, qui a accordé l'appel en priorité et les tarifs de rachat fixes généreux à la production d'électricité renouvelable (Ketterer, 2014). En plus de cela, des pays comme l'Espagne, la France, l'Italie et le Royaume-Uni sont également en première ligne pour le déploiement des technologies éolienne et solaire. Entre autres, le Danemark a atteint un niveau important de capacité installée d'énergie éolienne, étant donné la taille du pays, avec une capacité de plus de 5000 MW installés d'ici 2014. Bien que le niveau initial de capacités renouvelables soit encore faible dans certains pays, l'expansion de la capacité d'énergie renouvelable accélère dans de nombreux états européens avec un taux moyen annuel de croissance de plus de 50% sur la période 2000-2014. Par conséquent, avec ce progrès rapide et continu de l'énergie renouvelable, le système d'électricité actuel est sous une énorme pression de faire face à plusieurs propriétés spécifiques de production d'énergie renouvelable dans le but de maintenir la sécurité d'approvisionnement et la stabilité du système.

Comme mentionné ci-dessus, par rapport à la production conventionnelle à base de combustibles fossiles tels que le charbon et le gaz, l'énergie renouvelable a un profil de production distincte qui est très variable et difficilement prévisible. Ces caractéristiques de l'énergie renouvelable sont appelées l'intermittence, et celle-ci est plus prononcée pour la production éolienne. Comme facteur disruptif, une grande pénétration de l'éolien entraîne des fluctuations instantanées de l'offre résiduelle pour les générateurs classiques et nécessite donc un système de production plus souple. Comme l'ont souligné Hirth et al. (2015), trois spécificités de l'énergie éolienne le rendent difficile à intégrer dans le système de l'électricité : la variabilité temporelle, l'incertitude de la génération, et les contraintes de localisation. Les nouvelles dimensions temporelles et spatiales de la production d'énergie éolienne nous incitent à chercher comment d'un côté

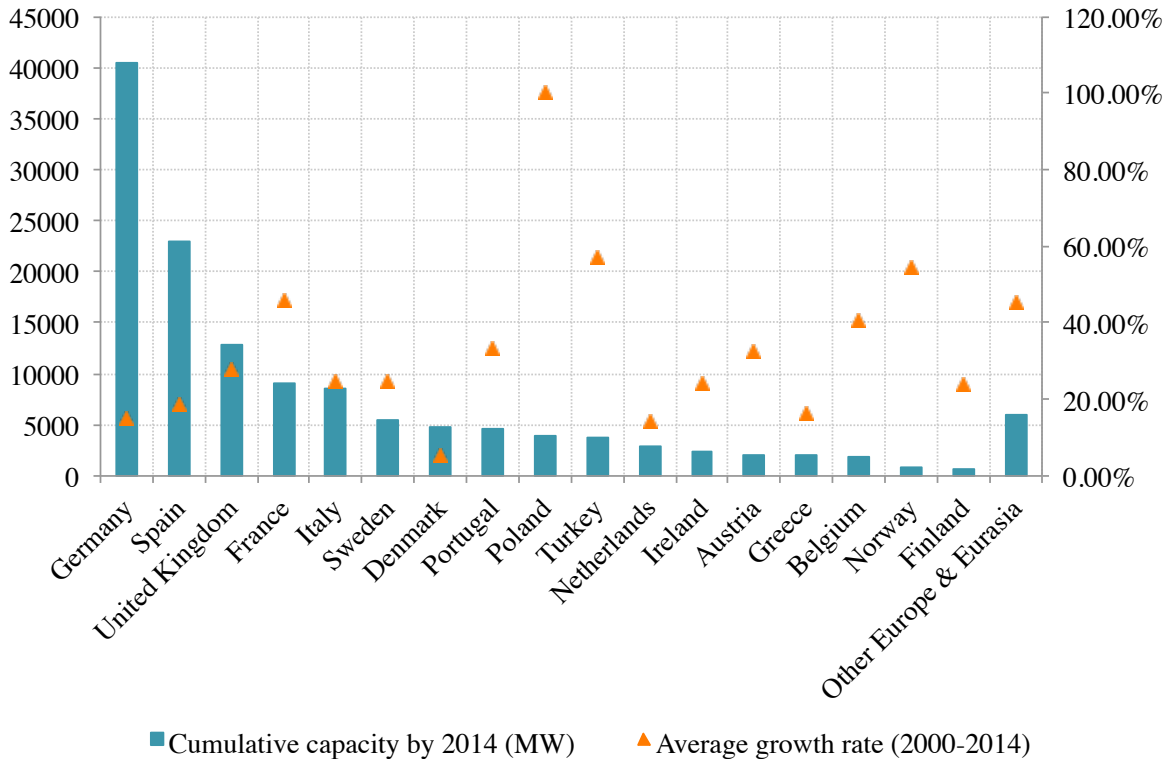


Figure 6 – Capacité installée de l'énergie éolienne d'ici 2014 (MW) et taux de croissance moyenne annuel entre 2000-2014. Source: BP Statistical Review. Réalisation de l'auteur.

concilier en temps réel le conflit entre la hausse des coûts d'équilibrage et les exigences plus grandes en réserves à court terme (Jacobsen et Zvingilaite, 2010) et de l'autre côté évaluer la vraie valeur de l'énergie éolienne en tenant compte de sa transportabilité en fonction du temps, du lieu et de l'intermittence (Borenstein, 2012). Cela implique une transformation systématique du secteur actuel de l'électricité, autant techniquement qu'économiquement. D'une part, les flux de la production éolienne imposent des chocs constants au marché de l'électricité et à leurs tours, modifient sensiblement les signaux du marché à tous les participants. Pour cette raison, une meilleure gestion des risques de la part des participants et une plus grande intégration du marché international sont nécessaires pour compenser l'incertitude apportée par l'énergie éolienne sur le marché spot. D'autre part, parce que la production d'électricité éolienne ne peut être prédite précisément d'un jour à l'autre, il y a un besoin à la fois d'améliorer les prévisions de

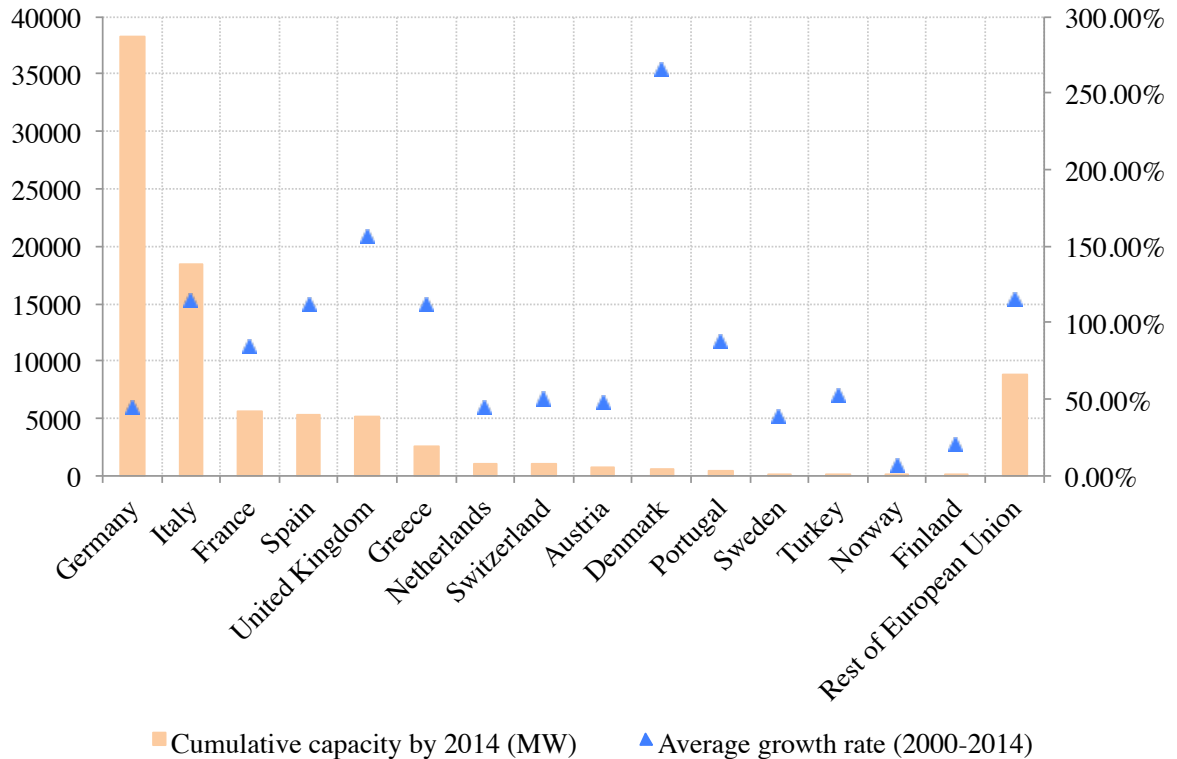


Figure 7 – La capacité installée de l’énergie solaire d’ici 2014 (MW) et taux de croissance moyenne annuel entre 2000 au 2014. Source: BP Statistical Review. Réalisation de l’auteur.

production éolienne et d’utiliser un mécanisme efficace d’échange avec un délai plus court pour pouvoir réduire l’incertitude de la production intermittente.

En ce qui concerne l’examen des signaux dans les marchés au comptant de l’électricité, ce n’est pas une tâche facile car les prix de l’électricité un jour d’avance présentent souvent de la saisonnalité, des corrélations temporelles, du retour à la moyenne, des pointes, de l’asymétrie et des queues épaisses (Bordignon et al ., 2013; Higgs, 2009;. Huisman et al, 2007; Jónsson et al, 2010). Pour cette raison, il est nécessaire de supprimer le caractère saisonnier, ce qui est suffisant pour capturer les propriétés du prix de l’électricité (Janczura et Weron, 2010), sinon l’impact des énergies renouvelables ne peut être identifié avec succès. Pour clarifier les impacts de la production d’énergie éolienne sur les marchés day-ahead, un effet de l’ordre du mérite (merit order effect) a été communément reconnu. Comme le montre la Fig. 8, l’effet de l’ordre du mérite

explique un abaissement du prix de marché de l'électricité par une augmentation de l'offre des énergies renouvelables. La variation du prix de l'ordre du mérite peut être décomposée en deux aspects: d'abord, la génération d'énergie éolienne peut déplacer la courbe globale d'alimentation à droite et donc l'offre résiduelle pour les producteurs classiques compétitifs est inférieure; ensuite, comme la production éolienne est généralement envoyée avant la production conventionnelle, la demande totale pour les technologies conventionnelles est également abaissée. Par conséquent, les prix au comptant de l'électricité diminuent inversement avec la quantité d'énergie éolienne alimentée dans le système. Ce résultat a été prouvé par une vaste littérature. Voir par exemples, Forrest et MacGill (2013), Vert et Vasilakos (2012), Traber et Kemfert (2011), et Woo et al. (2011). Cependant, il est difficile de décrire le profil de production pour les périodes où la production éolienne est faible, puisque alors qu'on aurait pu s'attendre à ce que des installations au mi-mérite prennent le pas, des usines très flexibles, à temps de démarrage court, sont activées pour faire face à l'intermittence de l'énergie éolienne et pour satisfaire constamment la demande finale. Dans ce cas, l'effet combiné des coûts de rampes et marginaux très élevés associés aux usines d'équilibrage et de l'exercice du pouvoir de marché peuvent créer des pics de prix plus élevés que le niveau de prix contrefactuel sans présence d'éoliennes dans le système. L'oscillation entre les niveaux de prix extrêmement hauts et bas produira certainement une volatilité importante, mais l'ampleur des fluctuations des prix et de la volatilité induite dans le marché day-ahead dépend des caractéristiques du marché ainsi que de la composition des technologies de production dans chaque pays. Plus précisément, le niveau des prix au cours de la période de faible vent est largement déterminé par les coûts associés aux technologies qui sont utilisées pour compenser l'intermittence du vent.

En ce qui concerne l'incertitude de la production d'énergie éolienne en raison de sa faible prévisibilité, Borggrefe et Neuhoff (2011) ont démontré qu'elle peut être réduite grâce à des prévisions améliorées. La possibilité de mettre à jour l'engagement de l'offre à son tour a besoin d'une conception du marché qui permet aux éoliennes et d'autres acteurs du marché d'ajuster leurs offres day-ahead jusqu'au temps réel. Suivant cette idée, la création d'un marché intra-journalier (intraday market) peut favoriser la flexibilité du système électrique pour faire face à l'incertitude dans la production renouvelable, et ce mécanisme mis en service dans plusieurs marchés européens de l'électricité sous la

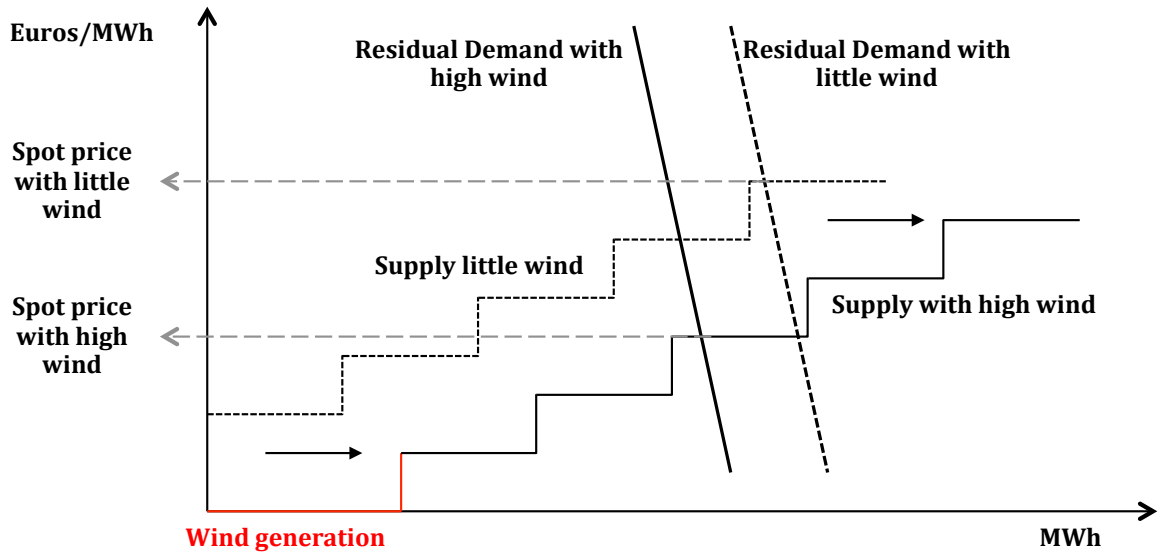


Figure 8 – Illustration de l'effet de l'ordre du mérite. Réalisation de l'auteur.

Notes: Chaque étape de la courbe d'offre représente la quantité d'électricité produite par un type de technologie de génération. Un déplacement à droite sur la courbe de l'offre implique un passage à une technologie différente de génération avec un coût variable plus élevé.

forme soit d'échanges bilatéraux en temps continu (par exemple à EPEX Spot et à Nord Pool Spot) ou de ventes aux enchères limitées à certaines heures (à OMIE) avant la livraison physique de l'électricité.³ Économiquement parlant, les producteurs d'énergie éolienne devraient avoir un fort intérêt à échanger de l'électricité sur les marchés intra-journaliers puisque leurs prévisions de production deviennent plus précises au fur et à mesure du temps, et ce faisant, ils peuvent éviter des coûts plus élevés de services d'équilibrage, ainsi que des sanctions de déséquilibres imposées par les régulateurs si les déséquilibres ne sont toujours pas résolus au moment de la livraison physique. En dépit de la raison économique évidente à utiliser les marchés intra-journaliers pour mettre à jour ou réinitialiser les calendriers de production, une faible liquidité a été observée sur plusieurs marchés intra-journaliers. Ce phénomène a été considéré comme un échec de cette conception du marché par certains chercheurs (Furió et al, 2009; Weber, 2010). Contrairement à la préoccupation de liquidité, un point de vue différent a également

³L'OMIE gère le marché au comptant de la péninsule ibérique, de la même manière que Nord Pool Spot le fait dans les pays nordiques, et EPEX Spot en France, en Allemagne et dans d'autres pays d'Europe centrale.

été mis en avant, qui est que l'efficacité d'un marché intra-journalier ne peut être jugée par son volume de négociation, car les agents économiques se comportent dans leur meilleur intérêt selon les signaux de prix reçus dans la limite fournie par le cadre de la politique (Henriot, 2014; Mauritzen, 2015). En conséquence, l'utilité d'un marché intra-journalier devrait s'appuyer à la fois sur la flexibilité du système, qui est corrélée négativement avec les coûts de rebalancement, et sur la capacité à résorber les erreurs de prévision de vent. Pour une conception de marché d'intraday efficace, ces éléments devraient être reflétés dans les signaux de prix intraday. Ce sera l'objet de cette thèse de développer cet argument ainsi que d'autres sujets.

Sujets de la thèse

Pour tenter d'apporter des réponses aux défis susmentionnés, cette thèse se décompose en quatre articles empiriques ou théoriques qui discutent des sujets critiques liés à la nouvelle dynamique dans le secteur de l'électricité. Elle ne porte pas sur une question de recherche unifiée, mais étudie plutôt les changements en cours et leurs impacts sur les marchés de l'électricité d'après trois perspectives : (1) de la macroéconomie, (2) de la configuration structurelle, et (3) de la transition vers des sources d'énergie renouvelables. Plus précisément, trois thèmes principaux émergent: le lien entre consommation d'électricité et croissance économique, les effets de l'intégration verticale entre producteurs et détaillants, et les impacts de la production d'énergie renouvelable intermittente sur les marchés de l'électricité. Comme la compréhension de la sécurité d'approvisionnement en jeu avec la création des systèmes d'électricité efficaces et intégrés demande une application combinée de politiques de croissance économique, de concurrence, et de soutiens aux renouvelables, les trois sujets abordés par cette thèse sont choisis pour être représentatifs pour correspondre à ces trois types d'applications stratégiques. Suite à une structure de haut en bas, cette thèse identifie la quantité agrégée de la consommation d'électricité comme contributeur au développement économique, et les signaux de prix comme reflet de la concurrence décentralisée et des influences de l'énergie renouvelable. En outre, elle met en lumière les risques sur l'approvisionnement et sur les prix du marché ainsi que les incertitudes intermittentes de renouvelables dans les réseaux électriques. Ainsi, quatre documents qui analysent

les questions ci-dessus sont présentés dans les chapitres 1 à 4.

Le premier chapitre présente le concept classique de relations causales entre la consommation d'électricité et la croissance économique.⁴ Ce sujet est bien important parce qu'une détermination des directions de causalité entre eux sert comme une étape nécessaire et indispensable pour élaborer des politiques de conservation de l'énergie et de croissance. À cette fin, le chapitre 1 présente l'examen le plus complet à ce jour de la dynamique à long et court terme entre la consommation d'électricité et les activités économiques, en utilisant des données de panel de la consommation d'électricité par habitant et du PIB par habitant de 160 pays pour la période allant de 1980 à 2010. En outre, le degré de dépendance de l'électricité et le niveau d'urbanisation sont pris en compte dans les deux choix de modélisation. Différents sous-échantillons en fonction des niveaux de revenus des pays, de la localisation régionale et de l'adhésion à l'OCDE sont également analysés afin de capturer les hétérogénéités du panel. Jusqu'à présent, aucune étude n'a examiné le lien entre la consommation d'électricité et la croissance économique d'une manière approfondie, en considérant tous les aspects mentionnés ci-dessus. Par rapport à la littérature existante, cette étude est menée dans le cadre géographique le plus large afin de capturer au mieux l'hétérogénéité dans la dynamique à court et long terme des relations entre la consommation d'électricité et la croissance. Elle intègre également un cadre multivarié comprenant les importations nettes d'électricité et l'urbanisation comme variables explicatives, ce qui n'est que rarement pris en compte par la littérature précédente ; mais comme le prouve ce document, ces variables sont essentiels pour déterminer le montant de la consommation d'électricité d'un pays donné et son degré de dépendance énergétique. Comme résultats, les liens causaux entre la consommation électrique et la croissance économique montrent une sensibilité considérable à ces hétérogénéités des pays. Dans les pays développés, le lien entre le PIB et la demande d'électricité présente peu de causalité, contrairement au lien fort dans le long terme dans les pays à faible revenu. De plus, l'urbanisation ou les importations et exportations de l'électricité sont des facteurs importants pour déterminer le niveau de la consommation dans les pays sous-développés ou en voie de développement, car ils ont souvent un niveau de consommation électrique limité soit par la disponibilité de l'accès

⁴Une version précédente de ce chapitre a été publié sous Karanfil, F., Li, Y., 2015. Electricity consumption and economic growth: exploring panel-specific differences. *Energy Policy*, 82, 264-277.

à l'électricité soit par l'intégration insuffisante du marché. Ces problèmes sont encore plus graves dans les régions telles que l'Afrique sub-saharienne et l'Asie du Sud. Ces résultats nous ont conduit à conclure que l'élaboration de la politique de l'énergie peut être faite d'une manière plus indépendante de la trajectoire économique des pays, qui ont déjà atteint un niveau élevé de revenu, une grande population urbaine, et une intégration avancée des marchés. Sinon, les impacts des politiques concernant les marchés de l'énergie sur la croissance économique ne peuvent assurément être ignorés.

Le chapitre 2 présente un cadre théorique pour étudier les effets des contrats à terme sur la concurrence quand un producteur et un détaillant peuvent être intégrés verticalement.⁵ Comme mentionné précédemment, des réformes vigoureuses sur les marchés de l'électricité depuis les années 1990 ont mis en place une séparation de la production et de la distribution des anciens monopoles et ont créé une série de marchés séquentiels visant à empêcher les producteurs dominants d'exercer un pouvoir de marché. Les marchés à terme ont été conçus dans cette logique. Bien que les modèles d'oligopole d'intégration verticale et de mouvements stratégiques dans les marchés à terme aient été documentés par certains chercheurs, les impacts de l'intégration verticale sur les contrats à terme et sur la concurrence ont peu été pris en considération. Plus important encore, le réglage spécifique dans le marché de gros de l'électricité obligeant les acteurs à négocier sur un unique marché centralisé exclut de fait la possibilité d'éviction anticoncurrentielle résultant d'une fusion verticale. Par conséquent, à la différence de la littérature précédente qui met l'accent sur la possibilité de d'éviction anticoncurrentielle, le deuxième chapitre avance la proposition que l'effet anti-concurrentiel d'une intégration verticale dans les marchés de l'électricité pourrait être atteint grâce à des ajustements de quantité de vente sous le contrat à terme. En outre, ce chapitre souligne l'aversion aux risques des producteurs et de détaillants dans leurs stratégies de négociation. Plus précisément, il montre qu'une intégration verticale entre un producteur et un détaillant, sous certaines conditions, réduit la quantité de contrats à terme et augmente le prix au comptant à l'équilibre, de sorte que les avantages compétitifs des contrats à terme sont contrecarrés. Pour déterminer cet effet concurrentiel, l'aversion au risque des producteurs et des détaillants est essentielle. De plus, il relève les raisons sous-jacentes à l'effet concurrentiel

⁵Ce chapitre est basé sur le document de travail : Li, Y., 2014. Vertical Structure and Forward Contracts in Electricity Markets. Department of Research, Ipag Lab.

négatif de l'intégration verticale. Celles-ci sont : (1) comme instrument de couverture structurelle, l'intégration verticale est utilisée par le détaillant intégré à la place des contrats à terme; (2) la dépendance des bénéfices sur les actifs de production donne une incitation plus élevée au détaillant intégré d'augmenter le prix au comptant. Par conséquent, cet effet anti-concurrentiel potentiel devrait préoccuper les autorités de la concurrence.

En utilisant des techniques économétriques, les chapitres 3 et 4 étudient les impacts de la production éolienne sur les marchés d'électricité day-ahead et intraday avec un accent particulier sur le Danemark et les autres pays nordiques qui ont déployés à grande échelle des éoliennes.⁶ Ces deux chapitres cherchent à répondre aux questions suivantes: d'abord, quelles sont les répercussions sur le marché de production d'énergie renouvelable; ensuite, comment faire face à des déséquilibres entraînés par l'incertitude de l'intermittence. Se référant à la première question, le chapitre 3 étudie les impacts de la production d'énergie éolienne intermittente au Danemark sur le prix du marché day-ahead et sur sa volatilité sur le marché nordique de l'électricité. Contrairement à la plupart de la littérature sur le sujet qui employait des données avec une fréquence quotidienne, ce chapitre se distingue en utilisant des données horaires afin de mieux représenter la variabilité et l'incertitude de l'énergie éolienne. Il est également le premier travail économétrique à tenir compte de l'intégration du marché nordique et de l'effet d'équilibrage de l'énergie hydroélectrique pour compenser la variabilité de la production éolienne. Ce dernier effet est mesuré par les échanges transfrontaliers entre le Danemark, la Norvège et la Suède. Par ailleurs, un examen complet des fondamentaux propres aux marchés nordiques, ainsi que des propriétés uniques de saisonnalité et d'asymétrie du prix de l'électricité day-ahead offre une vue novatrice à la fois sur les impacts de l'énergie éolienne, et sur les prévisions de prix et de volatilité. Les résultats montrent que la production éolienne réduit les prix au comptant et, plus surprenant, leur volatilité. Cette baisse de la volatilité intervient lorsque nous prenons en compte

⁶Le chapitre 3 est basé sur le document de travail : Li, Y., 2015. Revisiting short-term price and volatility dynamics in day-ahead electricity markets with rising wind power. Chaire European Electricity Markets.

Le chapitre 4 est basé sur à la fois une version révisée pour une resoumission à *the Energy Journal*, et le document de travail: Karanfil, F., Li, Y., 2015. Wind up with continuous intraday electricity markets? The integration of large-share wind power generation in Denmark. Chaire European Electricity Markets.

les aspects spécifiques du marché nordique, qui sont d'une part une substitution entre la production éolienne et la production hydraulique, et d'autre part des réseaux extensifs internationaux. Ces deux spécificités dans les pays nordiques rendent les signaux de prix relativement stables. Nous insistons sur le point qu'il faut en plus tenir compte de certaines propriétés statistiques du prix de l'électricité afin de préciser l'impact des éoliennes et d'obtenir une prédiction précise du prix ou de la volatilité.

Correspondant à la deuxième question soulevée ci-dessus, le chapitre 4 suggère une idée innovatrice pour examiner le fonctionnement d'un marché intra-journalier en testant les causalités entre ses fondamentaux. Un marché de l'électricité intraday est conçu pour permettre aux participants du marché d'ajuster leurs quantités d'engagement dans un marché day-ahead selon les prévisions améliorées, et il joue un rôle de plus en plus important dans l'intégration des éoliennes. Ce chapitre examine les principaux facteurs de l'écart entre le prix intraday et le prix day-ahead, et les causalités entre les erreurs de prévision du vent et d'autres facteurs. Bien que les techniques économétriques classiques sont employées dans ce chapitre, l'originalité vient de l'idée nouvelle de déduire la fonctionnalité d'un marché intra-journalier d'un moyen de tests de causalité, alors que de nombreux chercheurs considèrent généralement la liquidité comme un critère standard. En plus, cette étude est la première à décrire les chemins transitoires des éléments de marché et leur persistance qui résultent d'un choc d'erreur de prédiction de la production éolienne ou de manière équivalente, d'une incertitude du vent. Comme le montrent les résultats, les erreurs de prédictions de l'éolien et des technologies conventionnelles entraînent de façon significative des différences de prix entre l'intra-journalier et le day-ahead, et que le prix d'intra-journalier diminue avec la quantité inattendue de production éolienne. Pour résumer, ce chapitre fournit la première preuve du fonctionnement harmonieux du marché intra-journalier dans le cas du Danemark, où l'incertitude intermittente de la production est effectivement réduite par les transactions intra-journalières, et où les erreurs de prévision de la production éolienne sont traitées conjointement par les réponses de la demande, de la production conventionnelle et des transactions internationales intra-journalières.

Bibliography

- [1] Aghion, P., Bolton, P., 1987. Contracts as a Barrier to Entry. *The American economic review*, 388-401.
- [2] Allaz, B., Vila, J. L., 1993. Cournot competition, forward markets and efficiency. *Journal of Economic theory*, 59(1), 1-16.
- [3] Bordignon, S., Bunn, D. W., Lisi, F., Nan, F., 2013. Combining day-ahead forecasts for British electricity prices. *Energy Economics*, 35, 88-103.
- [4] Borenstein, S., 2000. Understanding competitive pricing and market power in wholesale electricity markets. *The Electricity Journal*, 13(6), 49-57.
- [5] Borenstein, S., 2012. The private and public economics of renewable electricity generation. *Journal of Economic Perspectives*, 26(1), 67-92.
- [6] Borggrefe, F., Neuhoff, K., 2011. Balancing and intraday market design: Options for wind integration.
- [7] Bushnell, J., 2007. Oligopoly equilibria in electricity contract markets. *Journal of Regulatory Economics*, 32(3), 225-245.
- [8] Chen, S. T., Kuo, H. I., Chen, C. C., 2007. The relationship between GDP and electricity consumption in 10 Asian countries. *Energy Policy*, 35(4), 2611-2621.
- [9] Ciarreta, A., Zarraga, A., 2010. Economic growth-electricity consumption causality in 12 European countries: A dynamic panel data approach. *Energy Policy*, 38(7), 3790-3796.

- [10] Crawford, G. S., Crespo, J., Tauchen, H., 2007. Bidding asymmetries in multi-unit auctions: implications of bid function equilibria in the British spot market for electricity. *International Journal of Industrial Organization*, 25(6), 1233-1268.
- [11] Creti, A., Manca, F., Garante, A., 2005. Mandatory electricity contracts as competitive device. Autorità Garante della Concorrenza e del Mercato.
- [12] European Commission (EC), 2010. Energy 2020 a strategy for competitive, sustainable and secure energy, Brussels.
- [13] European Commission (EC), 2011. A Roadmap for moving to a competitive low carbon economy in 2050, Brussels.
- [14] European Commission (EC), 2014. Energy prices and costs in Europe, Brussels.
- [15] Fabra, N., Toro, J., 2003. The fall in British electricity prices: market rules, market structure, or both?.
- [16] Fabra, N., Von der Fehr, N. H., Harbord, D., 2006. Designing electricity auctions. *RAND Journal of Economics*, 23-46.
- [17] Fehr, V. N., Mørch, N.H., Harbord, D., 1993. Spot market competition in the UK electricity industry. *The Economic Journal*, 531-546.
- [18] Forrest, S., MacGill, I., 2013. Assessing the impact of wind generation on wholesale prices and generator dispatch in the Australian National Electricity Market. *Energy Policy*, 59, 120-132.
- [19] Furió, D., Lucia, J. J., Meneu, V., 2009. The Spanish Electricity Intraday Market: Prices and Liquidity Risk. *Current Politics and Economics of Europe*, 20, 1-22.
- [20] García-Díaz, A., Marín, P. L., 2003. Strategic bidding in electricity pools with short-lived bids: an application to the Spanish market. *International Journal of Industrial Organization*, 21(2), 201-222.
- [21] Giuliotti, M., Grossi, L., Waterson, M., 2010. Price transmission in the UK electricity market: Was NETA beneficial?. *Energy Economics*, 32(5), 1165-1174.

- [22] Gnansounou, E., 2008. Assessing the energy vulnerability: Case of industrialised countries. *Energy Policy*, 36(10), 3734-3744.
- [23] Green, R. J., Newbery, D. M., 1992. Competition in the British electricity spot market. *Journal of political economy*, 929-953.
- [24] Green, R. J., 2004. Retail competition and electricity contracts.
- [25] Green, R.J., Vasilakos, N., 2012. Storing Wind for a Rainy Day: What kind of electricity does Denmark export?. *The Energy Journal*, 33(3), 1-22.
- [26] Hart, O., Tirole, J., Carlton, D. W., Williamson, O. E. 1990. Vertical integration and market foreclosure. *Brookings papers on economic activity*. Microeconomics, 205-286.
- [27] Henriot, A., 2014. Market design with centralized wind power management: handling low-predictability in intraday markets. *The Energy Journal*, 35(1), 99-117.
- [28] Higgs, H., 2009. Modelling price and volatility inter-relationships in the Australian wholesale spot electricity markets. *Energy Economics*, 31(5), 748-756.
- [29] Hirth, L., Ueckerdt, F., Edenhofer, O., 2015. Integration costs revisited—An economic framework for wind and solar variability. *Renewable Energy*, 74, 925-939.
- [30] Huisman, R., Huurman, C., Mahieu, R., 2007. Hourly electricity prices in day-ahead markets. *Energy Economics*, 29(2), 240-248.
- [31] International Energy Agency (IEA), 2014. Africa energy outlook: A focus on energy prospects in Sub-Saharan Africa, Paris.
- [32] International Electrotechnical Commission (IEC), 2015. Electrical energy storage, Genova.
- [33] Jacobsen, H. K., Zvingilaite, E., 2010. Reducing the market impact of large shares of intermittent energy in Denmark. *Energy Policy*, 38(7), 3403-3413.
- [34] Janczura, J., Weron, R., 2010. An empirical comparison of alternate regime-switching models for electricity spot prices. *Energy economics*, 32(5), 1059-1073.

- [35] Jónsson, T., Pinson, P., Madsen, H., 2010. On the market impact of wind energy forecasts. *Energy Economics*, 32(2), 313-320.
- [36] Joskow, P. L., 1997. Restructuring, competition and regulatory reform in the US electricity sector. *The Journal of Economic Perspectives*, 119-138.
- [37] Joskow, P., Tirole, J., 2006. Retail electricity competition. *The Rand Journal of Economics*, 37(4), 799-815.
- [38] Ketterer, J. C., 2014. The impact of wind power generation on the electricity price in Germany. *Energy Economics*, 44, 270-280.
- [39] Klemperer, P. D., Meyer, M. A., 1989. Supply function equilibria in oligopoly under uncertainty. *Econometrica: Journal of the Econometric Society*, 1243-1277.
- [40] Kraft, J., Kraft, A., 1978. Relationship between energy and GNP. *J. Energy Dev.:(United States)*, 3(2).
- [41] Narayan, P. K., Prasad, A., 2008. Electricity consumption–real GDP causality nexus: Evidence from a bootstrapped causality test for 30 OECD countries. *Energy Policy*, 36(2), 910-918.
- [42] Newbery, D. M., 1998. Competition, contracts, and entry in the electricity spot market. *The RAND Journal of Economics*, 726-749.
- [43] Payne, J. E., 2010. A survey of the electricity consumption-growth literature. *Applied energy*, 87(3), 723-731.
- [44] Powell, A., 1993. Trading forward in an imperfect market: the case of electricity in Britain. *The Economic Journal*, 444-453.
- [45] Rey, P., Tirole, J. 2007. A primer on foreclosure. *Handbook of industrial organization*, 3, 2145-2220.
- [46] Traber, T., Kemfert, C., 2011. Gone with the wind?-Electricity market prices and incentives to invest in thermal power plants under increasing wind energy supply. *Energy Economics*, 33(2), 249-256.

- [47] Twomey, P., Neuhoff, K., 2010. Wind power and market power in competitive markets. *Energy Policy*, 38(7), 3198-3210.
- [48] US Energy Information Administration (EIA), 2013. Annual Energy Outlook, Washington DC.
- [49] Weber, C., 2010. Adequate intraday market design to enable the integration of wind energy into the European power systems. *Energy Policy*, 38(7), 3155-3163.
- [50] Wolak, F. A., 2007. Quantifying the supply-side benefits from forward contracting in wholesale electricity markets. *Journal of Applied Econometrics*, 22(7), 1179-1209.
- [51] Wolfram, C. D., 1999. Measuring duopoly power in the British electricity spot market. *American Economic Review*, 805-826.
- [52] Woo, C. K., Horowitz, I., Moore, J., Pacheco, A., 2011. The impact of wind generation on the electricity spot-market price level and variance: The Texas experience. *Energy Policy*, 39(7), 3939-3944.
- [53] World Bank, 2015. Urbanization in Africa: Trends, promises, and challenges, Washington DC.
- [54] Yoo, S. H., 2006. The causal relationship between electricity consumption and economic growth in the ASEAN countries. *Energy policy*, 34(18), 3573-3582.

Chapter 1

Electricity consumption and economic growth: Exploring panel-specific differences

1 *

¹A previous version of this chapter has been published as Karanfil, F., Li, Y., 2015. Electricity consumption and economic growth: exploring panel-specific differences. *Energy Policy*, 82, 264-277.

1.1 Introduction

As one of the major components of energy consumption, the importance of electricity to economic growth has been recognized not only by economists, but also by businessmen, engineering, energy and government agencies. As stated by the US Energy Information Administration (EIA): “a country’s economy and its energy use, particularly electricity use, are linked. Short-term changes in electricity use are often positively correlated with changes in economic output” (EIA, 2013b).²

Generally speaking, the relationship between electricity consumption and economic growth can be categorized into four testable causal hypotheses: (1) growth hypothesis assumes that electricity is a necessary factor of economic growth, implying thus a causality running from electricity to economic growth; (2) conservation hypothesis postulates a causality running from economic growth to electricity consumption; (3) feedback hypothesis emphasizes the interdependence between electricity consumption and economic growth; (4) neutrality hypothesis assumes no causal link. In order to make proper policy suggestions, it is necessary and essential to clarify the relationship and the direction of causality between them.

The purpose of the present chapter is to complement and extend the previous literature that has investigated the causal relationship between economic growth and electricity consumption, which has so far provided conflicting results. To do so, we add cross-sectional dimension to increase the power of various tests in a multivariate framework, which addresses the problem of omitted variable bias and accounts for different characteristics across countries. More specifically, using panel data of per capita electricity consumption and per capita real Gross Domestic Product (GDP) for 160 countries,³ this chapter examines both the long- and short-run dynamics between electricity consumption and economic activities, taking into account the degree of electricity

²EIA showed that the US electricity use and economic growth are linked as suggested by data over the past 60 years. The projection through 2040 also shows that this relationship is about to change in the US. See for more details (EIA, 2013b).

³To be more specific, independent territories and special administrative regions are treated separately. For example, Hong Kong is separated from China mainland for estimation. Independent territories like Netherlands Antilles and French Polynesia are considered as different countries from Netherlands and France. A complete country list with the indications of their geographic locations, income levels and the status of the OECD membership can be found in Table A1 in Appendix A.

dependence and the level of urbanization. Furthermore, in order to capture the differences in this relationship, the full sample is divided into: (1) four subsamples based on countries' income levels, (2) seven subsamples based on regional locations, and (3) two subsamples according to the identity of the OECD memberships.

The main contribution of this study is at least twofold. First, it attempts to determine the relationship between electricity consumption, economic growth, electricity dependence and urbanization in more detail and in a much broader geographic context compared to all previous studies. The 160 countries included in this chapter represent 96.52% of global GDP⁴ and 94.61% of global electricity consumption⁵ in 2010. While the correlation between electricity consumption and economic growth has been confirmed by many scholars, it is not homogeneous for all countries. Through correlation analyses for more than 100 countries, Ferguson et al. (2000) suggest that this relationship is stronger in wealthy countries and that the link with wealth creation would be more appropriately attributed to electricity consumption rather than energy use in general. Moreover, Yoo and Kwak (2010) show that electricity consumption-GDP nexus may have different forms depending on countries' income levels. Therefore, we choose to study electricity consumption-GDP nexus and conduct successively subsample studies by using three different criteria, which account for income, organizational and geographic differences across panels. Although this relationship seems to be of a long-term rather than short-term nature, from economic and energy policy viewpoints, studies in this field should integrate both short- and long-term perspectives. In the framework of the present study, the existence of a long-run causality indicates that the equilibrium between the variables involved in the analysis determines the level of electricity consumption, while a short-run causality signifies that some of these variables may have a delayed impact on electricity consumption that responds only to the short-term shocks. In other words, in the case of long-run relationship, movements along the equilibrium path are permanent whereas the interactions should be considered transitory in the case

⁴Sourced from the United Nations' database UNCTAD, the total GDP in 2010 is 51,263,609 million US dollars at 2005 constant prices and 2005 constant exchange rates. We calculate the percentage of the total GDP of sample countries in global GDP in 2010.

⁵The total electricity consumption in 2010, namely 17,780 billion kilowatt hour, is given by website Indexamundi (2013) sourced from CIA World Factbook. Other sources may provide information on total global electricity consumption with slight differences.

of short-run causality (or long-run non-causality). Thus, different policy implications emerge depending upon whether causality runs in the short and/or long run.

Second, we use a multivariate framework, which allows us to go beyond a simple GDP-electricity nexus. In addition to electricity consumption and GDP, we incorporate net import of electricity and urbanization. The reason for including these two variables in the framework of this study is straightforward. First, net import of electricity captures to what extent a given country is dependent on imported electricity. As indicated by Gnansounou (2008), the net import of electricity is one of the three sub-dimensions of the electricity dependency or supply vulnerability (the non-diversification of electricity generation and the risk of non-acceptance by the public of a dominated technology of electricity generation are cited to be the other two dimensions). Being a negative externality, energy supply risks constitute the policy issue of security of supply. Therefore the supply risks are addressed by striving to “bring production home”, which is an equal term as energy dependency (OECD, 2010). It is clear that high dependency may render the economy highly vulnerable to external shocks, and in this perspective, it may have an effect on the dynamic relationship between electricity consumption and income in the short run as well as in the long run. Fig. 1.1 is a visualization of the data of electricity net import or export in 2010.⁶ It shows that one electricity-export country is generally surrounded by electricity-import countries and vice versa.⁷ Electricity trade is generally localized within region. Due to high costs of storage and physical transmission constraints, electricity can be economically transported only over relatively short distances. Isolated island countries, such as Japan and Australia, must be able to cover national demand, therefore being electricity-independent. Hence the variable net import of electricity captures the flows of electricity exchange within one region. This gives further justification to our regional segmentation of the global data.

First of all, compared with energy dependency, electricity net import as a proxy for electricity dependency is meant to capture the flows of electricity among different countries. We believe that it is more suitable to measure how the possibility of cross-

⁶Negative values on net electricity import signify countries being net-exporters.

⁷As seen on the maps, the data of Russia and former member countries of the Soviet Union are excluded with caution due to the dissolution of the Soviet Union at the beginning of 90s. It is not appropriate to distribute these data before the 90s into 15 independent post-Soviet states. Accurate data do not exist even in the articles and reports written in Russian (Jobert et al., 2014).

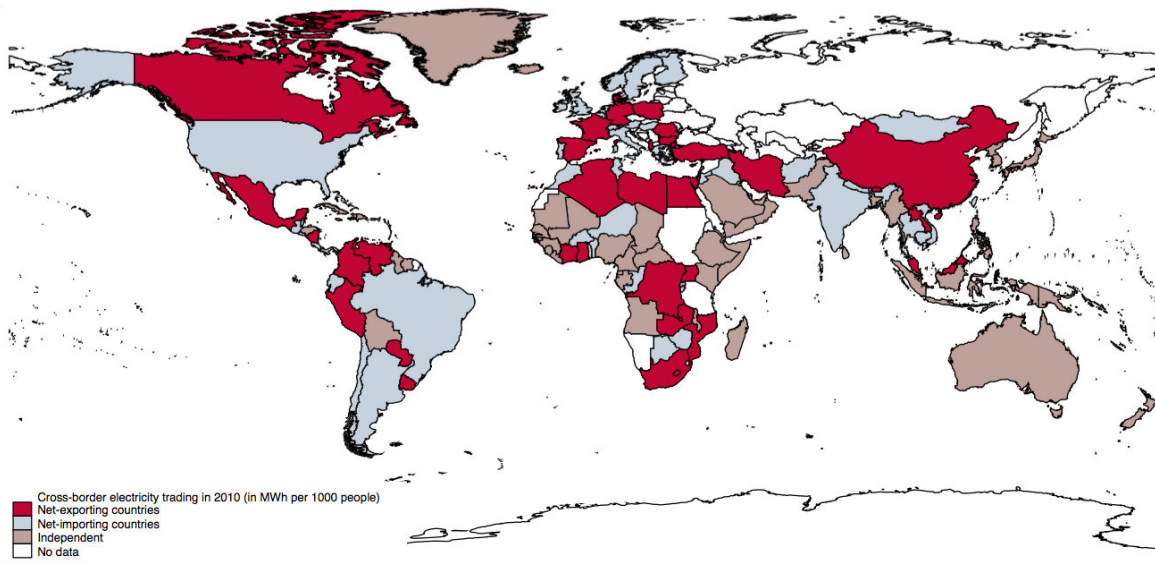


Figure 1.1 – Net electricity import across countries.

Data sources: Authors’ calculations based on (UNCTAD, 2013) and (EIA, 2013a).

border exchanges affects electricity consumption-growth nexus directly, rather than to estimate mixed impacts of the economic reliance on electricity generation inputs, e.g. coal, oil and gas. Electricity dependency is obviously linked directly to electricity consumption. However this link may not be necessarily found between energy dependency and electricity consumption. Related to this point, it should be also mentioned that some countries can be energy-dependent but not electricity-dependent (such as France). Consequently, households’ and firms’ behavior with respect to electricity use and resulting energy policies in the former countries cannot be as same as in the latter countries, and reasonably their electricity consumption dynamics can be better explained by using their electricity-dependency rather than energy dependency.

Second, the non-storability and variability of electricity require demand and supply to be always equalized in real time. Therefore, electricity net imports are a better measure for supply risks and the resulted economic vulnerability compared to aggregated energy net imports, since other storable energy commodities cannot reflect the urgency of immediate delivery as electricity dependency can.

Third, electricity exchanges are also an indicator for market integration, while the goal of creating integrated electricity market has been advocated in many regions of

the world. As a matter of fact, countries' income or income-electricity nexus relies on the extent of market integration, which reflects also transmission constraints and grid developments. However, all these electricity-specific characteristics cannot be captured by energy dependency.

Unlike net import of electricity, the progress of urbanization has been studied in the environmental and regional economics literature, mostly for the purpose of analyzing greenhouse gas (GHG) emissions in relation to energy use (e.g., O'Neill et al., 2012; Parikh and Shukla, 1995). However, when focusing on panel cointegration and panel causality, only a few studies take urbanization progress into account. Especially, when it is not conclusive whether urbanization has a significant effect on electricity consumption per capita, it is worth more research attention to search for the impacts of urbanization on electricity consumption. On the one hand, electricity is more accessible in urban areas and urban inhabitants plausibly possess more electronic belongings and lead a more "electricity-consuming" lifestyle compared to inhabitants in rural areas (Holtedahl and Joutz, 2004). This fact tends to increase electricity consumption per capita. On the other hand, a counter hypothesis can be put forward: an urbanization progress creates higher density of population and shorter travel distances in urban areas, which may decrease electricity consumption per capita (Poumanyvong and Kaneko, 2010; Chen et al., 2008). In addition, the impacts of urbanization on electricity use may not be homogeneous across countries or regions, and they may differ on countries' characteristics and development levels. According to a recent survey of the United Nations Development Policy and Analysis Division (DESA) (2013), while urbanization is growing, for the first time in history, the world's absolute number of rural inhabitants is declining. All in all, the provision of energy and more particularly electricity is the dominant element of economic sustainability. Detailed and extended analyses of the dynamic relationships between urbanization, electricity consumption and economic activities in different regions and with respect to different development levels remain as an important research agenda.

This chapter is organized as follows. Section 1.2 summarizes very briefly the empirical literature on electricity-growth or energy-growth nexus by exploring panel data, as well as describes the dataset used and the models employed in this study. Section 1.3 provides empirical results. Section 1.4 discusses these results, and finally, Section 1.5

concludes the chapter and gives policy implications.

1.2 Methods

1.2.1 Literature review

For the purpose of this chapter, we focus on studies that explore panel data properties. Table 1.1 summarizes the main findings of previous panel studies on the causal relationships between electricity consumption and economic growth. The first set of studies performs a bivariate analysis, using cointegration and Granger (1969) causality techniques and reports mixed findings. One can reasonably conclude that region- or country-specific characteristics may have an impact on the electricity-income nexus, and that the results may vary depending on whether the variables are at aggregate or disaggregate levels. To address this issue, at least partially, the second set of panel studies focus on countries having common characteristics, mostly members of the same international organizations such as G7, BRICS, or OECD. In the third set of studies, the databases generally contain heterogeneous countries across different continents. Finally, to avoid a possible omitted variable bias, some recent studies have employed multivariate frameworks.

Besides the above three sets of studies, it is worth taking a glance of literature on urbanization in connection with energy use. Although some studies on the determinants of energy demand and environmental impacts have used urbanization as an explanatory variable, it has been used very few times in the energy-GDP Granger causality studies. One of the studies, which is also somewhat close to our own, is the quite recent paper by Niu et al. (2013) who showed that a feedback relation exists between electricity consumption and urbanization, and that this relationship varies weakly while income increases. The paper by Mishra et al. (2009) represents another example for the same scheme. In fact, the impacts of urbanization on energy use are still under debate. Some scholars study the effect of urbanization on energy use in developing countries, and while doing so, they consider both the threat of GHG emissions and the expanding fossil fuel use brought by rapid urbanization process. For example, Liu (2009) shows that there exists only a unidirectional Granger causality running from urbanization

Table 1.1 – Summary of findings in panel causality studies

| Author | Period | Sample | Result |
|------------------------------|-------------|--------------------|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Yoo and Kwak (2010) | 1975 – 2006 | Latin America | EC → GDP: Argentina, Brazil, Chile, Columbia, Ecuador EC ↔ GDP Venezuela No causality: Peru EC → GDP: Hong Kong |
| Chen et al. (2007) | 1971 – 2001 | Asia | GDP → EC: India, Singapore, Malaysia, the Philippines No causality: Indonesia, Korea, Taiwan, Thailand Unidentified: China |
| Yoo (2006) | 1971 – 2002 | Asia | EC ↔ GDP Malaysia, Singapore GDP → EC: Indonesia, Thailand |
| Abbas and Choudhury (2013) | 1972 – 2008 | India, Pakistan | GDP → EC: India EC ↔ GDP: Pakistan |
| Saunoris and Sheridan (2013) | 1970 – 2009 | 48 states, US | EC → GDP: aggregate sample and industrial sector GDP → EC: Residential and commercial sectors |
| Wolde-Rufael (2006) | 1971 – 2001 | Africa | EC → GDP: Benin, Congo, DR., Egypt, Gabon, Morocco, Tunisia GDP → EC: Cameroon, Ghana, Nigeria, Senegal, Zambia, Zimbabwe No causality: Algeria, Congo, Rep., Kenya, South Africa, Sudan |
| Ciarreta and Zarraga (2010) | 1970 – 2007 | Europe | EC → GDP |
| Narayan and Smyth (2009) | 1974 – 2002 | Middle East | EC ↔ GDP |
| Narayan et al. (2008) | 1970 – 2002 | G7 | EC → GDP: Canada, Italy, France, Japan, Germany, UK GDP → EC: USA |
| Narayan and Prasad (2008) | 1965 – 2002 | OECD | EC → GDP: Australia, Iceland, Italy, Slovak, Czech, Korea, Portugal, the UK No causality: Belgium, Canada, Denmark, France, Germany, Greece, Ireland, Japan, Luxembourg, New Zealand, Norway, Poland, Spain, Sweden, Switzerland, Turkey, Mexico, USA EC ↔ GDP: Russia |
| Cowan et al. (2013) | 1990 – 2010 | BRICS | GDP → EC: South Africa No causality: China, Brazil, India |
| Acaravci and Ozturk (2010) | 1990 – 2006 | EU transition | No causality |
| Squalli (2007) | 1980 – 2003 | OPEC | EC → GDP: Algeria, Iraq, Libya GDP → EC: Kuwait, Saudi Arabia, United Arab Emirates EC ↔ GDP: Iran, Qatar |
| Niu et al. (2013) | 1990 – 2009 | 50 countries | EC ↔ GDP |
| Apergis and Payne (2011b) | 1990 – 2006 | 88 countries | EC ↔ GDP: high, upper middle income panels, lower middle income (LR) EC → GDP: lower middle income panels, low income panels |
| Narayan et al. (2010) | 1980 – 2006 | 93 countries | EC ↔ GDP GDP → EC: Middle East |
| Mishra et al. (2009) | 1980 – 2005 | PIC | E ↔ GDP |
| Liu (2009) | 1978 – 2008 | China | Urbanization → E |
| Hossain et al. (2011) | 1971 – 2007 | NIC | GDP → E: Brazil, China, India, Malaysia, Mexico, Philippines, South Africa, Thailand, Turkey |
| Apergis and Payne (2011a) | 1990 – 2007 | Emerging countries | GDP → renewable EC GDP ↔ non-renewable EC |
| Al-mulali et al. (2014) | 1980 – 2010 | Latin America | EC → GDP (with stronger effect of renewables) |

Notes: *E* stands for energy consumption, and *EC* stands for electricity consumption.

→ indicates the direction of one-way Granger causality, and ↔ indicates two-way Granger causality.

to total energy consumption in China in both the short and long runs. In a larger model, Hossain (2011) empirically examines the dynamics among carbon dioxide (CO₂) emissions, energy consumption, GDP growth, trade openness, and urbanization level for nine newly industrialized economies. The results reveal a causality running from urbanization to economic growth but no causality between urbanization and energy use.

The present chapter differs from all previous work in several aspects. It aims at making a further breakthrough on the dynamic links between electricity consumption and economic growth. The world is facing the challenge of surge in electricity demand that is driven by population growth, progressive urbanization, and globalization trend. In order to put the analysis into a global perspective, our study takes part in the third set of studies by including the largest number of countries and constructing 13 subsets according to regional, income and organizational differences. In addition to that, this work highlights the influences on electricity system vulnerability and globalization by means of electricity dependency. As discussed in the introductory section, urbanization and economic development are strictly linked to the variations in electricity intensity. In countries that are unable to produce required electricity power, rising electricity dependency makes them more vulnerable to electricity shocks. As such, their capacity to provide reliable supply to the consumers (both households and businesses) appears to be determinant in the electricity-income nexus. Note finally that while this reasoning seems to be sound and consistent and despite its potential role in the electricity usage and in turn in the level of economic activities, so far, previous studies have not addressed the dependency and supply vulnerability issues within the framework of GDP-energy causal nexus. Thus, the present chapter fills this gap and offers some interesting insights and policy implications.

1.2.2 Data

Data sources

The dataset used for estimation is constructed from different sources according to availability. The annual data for electricity consumption and net import are obtained for

160 countries from the US EIA for the period of 1980-2010.⁸ Electricity consumption per capita and electricity net import per capita are measured in kilowatt hour (kWh) per capita. The data on each country's economic level, population and percentage of urban population are sourced from the United Nation's database (UNCTAD). GDP per capita is measured in US Dollars at 2005 constant prices and exchange rates. We further construct subsets of the data based on income levels and geographic regions according to the classification of the World Bank (2013). Finally, a complete list of OECD countries can be found on the official OECD website (OECD, 2013), according to which OECD countries are separated from the rest. A number of countries have become the member countries of the Organization during the study period (e.g., Czech Republic, Hungary, Mexico), thus a country is categorized as OECD member as long as it has joined the Organization by the end of 2010.

Data description

Since we include as many as 160 countries, before entering in rigorous and panel econometric analyses, it is useful to inspect the evolution of electricity consumption and GDP in the full sample and subsamples. Fig. 1.2 shows the average trend of the series of electricity consumption and GDP in the global sample, with the values in 1980 normalized to 100 for comparisons.⁹ Analogously, the figures of the same series for all subsamples can be found in Appendix B.

Based on Fig. 1.2 the global average of electricity consumption grows faster than the average GDP and these two series grow steadily with slight stagnation at the beginning of 1980s. We consider that the world's economy started to recover from the 1970s' energy crisis since the beginning of 1980. During the energy crisis period, the major industrial economies of the world faced substantial real and perceived oil shortages, as well as elevated prices, but after 1980, oil prices began to decline as production started to recover (for more details, see Barsky and Kilian, 2004). A more recent setback hits electricity use and output growth in 2008 due to global financial crisis.¹⁰ While at the segmented level the comovement of GDP and electricity consumption has similarities

⁸The chosen period is constrained by the data availability for total electricity consumption.

⁹All average values are weighted by national population.

¹⁰For robustness check, the results are invariant to the exclusion of data after 2008.

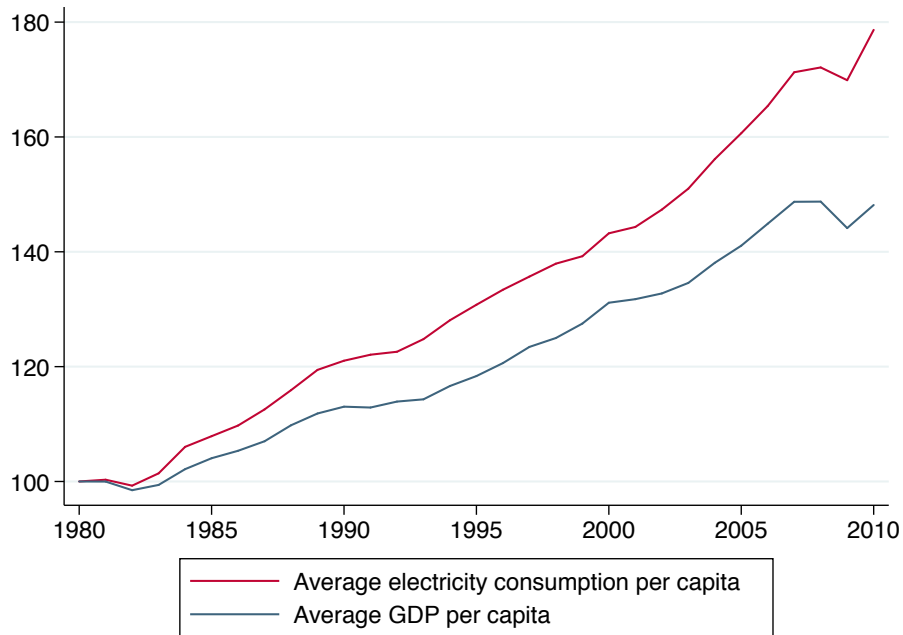


Figure 1.2 – Evolutions of electricity consumption and GDP for 160 countries.
 Data sources: Authors' calculations based on (UNCTAD, 2013) and (EIA, 2013a).

compared to the global panel, divergent temporal trends can be observed from subsamples. The evolutions of the same series in Fig. B.1 in Appendix B demonstrate heterogeneous trends depending on countries' OECD memberships, income levels and regional locations. Middle-income countries have been consuming electricity and creating income with increasing rates in the recent 30 years, whereas the growth rates of electricity use and GDP have been slowing down in high-income countries. For low-income countries and Sub-Saharan Africa region, economic growth and electricity use are disturbed during the 1980s. The economic activities and electricity consumption in these countries surge together since the early 1990s. Because of these, it is thus reasonable to expect the relationships between GDP and electricity consumption to be different among subsamples.

Estimation

To analyze the relationship between the aforementioned variables in a more analytical manner, the econometric framework employed in this chapter consists of panel unit root, cointegration and causality tests. In the first place, panel unit root tests are used to check the stationarity properties of each of the variables separately. The conventional augmented Dickey-Fuller (ADF) (Dickey and Fuller, 1979) tests may be weak in testing stationarity for panel data since they contain both time and cross-section dimensions. To address this issue, the recent literature proposes a number of panel unit root tests from which we chose to use LLC (Levin et al., 2002) and IPS (Im et al., 2003) panel unit root tests. While the former assumes common unit root for all panels in the sample, the latter relaxes this assumption and allows individual unit roots to be tested for each panel member separately.

The results of the panel unit root tests will determine the estimation strategy to be followed. If the variables are found to have unit root in their levels, but are stationary in their first differences, this indicates that the series are integrated of order one (i.e. $I(1)$) and thus a long-run equilibrium relationship can be investigated employing cointegration techniques.

To test the cointegration relationship we follow the methodology proposed by Pedroni (1999) who extends the Engle and Granger (1987) two-step procedure to the heterogeneous panel data framework. The equation to be estimated proposed by Pe-

droni (1999) can be written in our case in the following manner:

$$EC_{jt} = \mu_j + \gamma_1 GDP_{jt} + \gamma_2 M_{jt} + \gamma_3 U_{jt} + \epsilon_{jt} \quad (1.1)$$

where EC , GDP , M and U represent the variables for, respectively, electricity consumption, real GDP, electricity net imports (all in per capita terms), and urbanization ratio of country j in year t . On the other hand, μ_j is the country-specific intercept, ϵ_{jt} is an i.i.d. error term and the parameters γ_i with $i = 1, 2, 3$, are the slope coefficients that may be different for each country j . In this way the test accounts for a possible heterogeneity across countries. Just as in the standard Engle-Granger two-step approach, after predicting the residuals of Eq. (1.1), the second step of Pedroni's panel cointegration test consists of testing for unit root in ϵ_{jt} , that is

$$\epsilon_{jt} = \rho_j \epsilon_{jt-1} + u_{jt} \quad (1.2)$$

The null hypothesis of no cointegration becomes simply $\rho_j = 1$. Furthermore, based on the properties of the coefficient ρ_j , Pedroni (1999, 2004) proposes seven different tests for cointegration.¹¹

The cointegration test results will have implications for the model specifications that will be estimated in order to examine causal links among the variables. For any given panel, if the cointegration tests indicate that the variables are cointegrated, then there exist a long-run relationship between them and the direction of causality should be estimated using a vector error correction (VEC) model. Conversely, if no cointegrating vector is found, then a vector autoregression (VAR) model should be estimated.

In the framework of our analysis, a VAR model (Sims, 1980) including four non-stationary and non-cointegrated variables in first differences can be represented in the following system of equations:

¹¹A detailed discussion of these panel cointegration tests can be found in Pedroni (1999, 2004) along with their critical values.

$$\begin{aligned}\Delta EC_{jt} = & \psi_{1j} + \sum_{k=1}^n \gamma_{11jk} \Delta EC_{jt-k} + \sum_{k=1}^n \gamma_{12jk} \Delta GDP_{jt-k} + \sum_{k=1}^n \gamma_{13jk} \Delta M_{jt-k} \\ & + \sum_{k=1}^n \gamma_{14jk} \Delta U_{jt-k} + v_{1jt}\end{aligned}\quad (1.3)$$

$$\begin{aligned}\Delta GDP_{jt} = & \psi_{2j} + \sum_{k=1}^n \gamma_{21jk} \Delta EC_{jt-k} + \sum_{k=1}^n \gamma_{22jk} \Delta GDP_{jt-k} + \sum_{k=1}^n \gamma_{23jk} \Delta M_{jt-k} \\ & + \sum_{k=1}^n \gamma_{24jk} \Delta U_{jt-k} + v_{2jt}\end{aligned}\quad (1.4)$$

$$\begin{aligned}\Delta M_{jt} = & \psi_{3j} + \sum_{k=1}^n \gamma_{31jk} \Delta EC_{jt-k} + \sum_{k=1}^n \gamma_{32jk} \Delta GDP_{jt-k} + \sum_{k=1}^n \gamma_{33jk} \Delta M_{jt-k} \\ & + \sum_{k=1}^n \gamma_{34jk} \Delta U_{jt-k} + v_{3jt}\end{aligned}\quad (1.5)$$

$$\begin{aligned}\Delta U_{jt} = & \psi_{4j} + \sum_{k=1}^n \gamma_{41jk} \Delta EC_{jt-k} + \sum_{k=1}^n \gamma_{42jk} \Delta GDP_{jt-k} + \sum_{k=1}^n \gamma_{43jk} \Delta M_{jt-k} \\ & + \sum_{k=1}^n \gamma_{44jk} \Delta U_{jt-k} + v_{4jt}\end{aligned}\quad (1.6)$$

where ψ_{ij} with $i = 1, 2, 3, 4$, are constant terms and n is the optimal lag length based on Akaike's Information Criterion (AIC). For each of the equations involved in the VAR system, the short-run causal inferences can be tested using a Wald test. More formally, in order to test the existence of causality, for example, from GDP to EC, the following hypothesis testing should be considered in Eq. (1.3):

$$H_0 : \gamma_{12jk} = 0 \quad \forall k = 1, \dots, n$$

$$H_a : \exists \gamma_{12jk} \neq 0 \quad \forall k = 1, \dots, n$$

If the null hypothesis of no causality can be rejected, then it can be concluded that in the short run, real GDP per capita causes electricity consumption per capita in the sense of Granger.

In the case of non-stationary and cointegrated variables, a VEC model involves one-lagged error correction term in a VAR model, which takes then the following form:

$$\begin{aligned} \Delta EC_{jt} = & \psi_{1j} + \sum_{k=1}^n \gamma_{11jk} \Delta EC_{jt-k} + \sum_{k=1}^n \gamma_{12jk} \Delta GDP_{jt-k} + \sum_{k=1}^n \gamma_{13jk} \Delta M_{jt-k} \\ & + \sum_{k=1}^n \gamma_{14jk} \Delta U_{jt-k} + \omega_{1j} \epsilon_{jt-1} + v_{1jt} \end{aligned} \quad (1.7)$$

$$\begin{aligned} \Delta GDP_{jt} = & \psi_{2j} + \sum_{k=1}^n \gamma_{21jk} \Delta EC_{jt-k} + \sum_{k=1}^n \gamma_{22jk} \Delta GDP_{jt-k} + \sum_{k=1}^n \gamma_{23jk} \Delta M_{jt-k} \\ & + \sum_{k=1}^n \gamma_{24jk} \Delta U_{jt-k} + \omega_{2j} \epsilon_{jt-1} + v_{2jt} \end{aligned} \quad (1.8)$$

$$\begin{aligned} \Delta M_{jt} = & \psi_{3j} + \sum_{k=1}^n \gamma_{31jk} \Delta EC_{jt-k} + \sum_{k=1}^n \gamma_{32jk} \Delta GDP_{jt-k} + \sum_{k=1}^n \gamma_{33jk} \Delta M_{jt-k} \\ & + \sum_{k=1}^n \gamma_{34jk} \Delta U_{jt-k} + \omega_{3j} \epsilon_{jt-1} + v_{3jt} \end{aligned} \quad (1.9)$$

$$\begin{aligned} \Delta U_{jt} = & \psi_{4j} + \sum_{k=1}^n \gamma_{41jk} \Delta EC_{jt-k} + \sum_{k=1}^n \gamma_{42jk} \Delta GDP_{jt-k} + \sum_{k=1}^n \gamma_{43jk} \Delta M_{jt-k} \\ & + \sum_{k=1}^n \gamma_{44jk} \Delta U_{jt-k} + \omega_{4j} \epsilon_{jt-1} + v_{4jt} \end{aligned} \quad (1.10)$$

where, ϵ_{jt-1} , the error correction term, is the lagged estimated residual from Eq. (1.1). It measures the deviations of the variables EC , GDP , M and U from their long-run equilibrium relationship. While the short-run causalities can still be tested following

the same hypothesis testing procedure indicated in the VAR framework, the long-run causalities can now be examined by the significance of the error correction parameters ω_j . For example in Eq. (1.7) based on the t -statistics, the significance of ω_{1j} reveals that the variables GDP , M and U Granger causes EC in the long run. To assess the individual long-run causalities, the joint significance of the parameters γ_j and ω_j should be tested. For instance still in Eq. (1.7), based on Wald statistics, finding the parameters γ_{12jk} and ω_{1j} jointly significant implies that GDP causes EC both in the short- and long-run.

Finally, one may expect that electricity prices would be related to electricity demand and thus, to electricity consumption per capita. This may be realized in an analysis for a specific electricity market, but concerning this work, it is unnecessary and impossible to incorporate electricity prices for the following reasons. First, the objective of this study is to clarify the puzzle of consumption-growth nexus, and to reckon with the factors that could affect the causal relationships between electricity consumption and economic growth, rather than the electricity consumption solely. A demand-price relationship is not a focus. Second, electricity prices at the retail level are inflexible (compared with wholesale prices, for instance), and their links to demand may be weak. Both price levels and their variations are highly dependent on countries' regulations and economic conditions. In most developing and underdeveloped countries, electricity prices are usually under tight governmental control, while in many Western countries, a retail market mechanism has been gradually established since the 1990s. In Appendix E, we give a timeline of the achievement of full retail competition in some countries. Even for them, yet, it is important to state that an achievement of full retail competition does not imply flexibility in prices. It rather means that competition is allowed and end-users can switch among suppliers, but prices are still, to a great extent, pre-determined. This is also one of the reasons that electricity demand is often characterized as inelastic. Last but not least, the price data for 160 are simply not available. Even if regional proxies may be found, given huge disparities in market design, industry structure, control tightness, and economic status among so many countries, it is extremely difficult to determine a fair price for them.

1.3 Results

1.3.1 Unit root and cointegration results

We follow the estimation procedure described in the previous section. We begin with running LLC and IPS panel unit root tests. From these tests, it can be concluded that for all panels the variables are non-stationary in levels but stationary in first differences.¹² We then proceed to test for cointegration employing Pedroni's (1999) panel cointegration tests based on Eq. (1.1). The results are provided in Table 1.2. In some panels, all tests fail to reject the null of no cointegration while in some others mixed results are reported. In this situation, we follow Pedroni (2004), who, after having examined the small sample size properties of these tests, indicated that when the time dimension is small, the group-ADF statistic usually performs best, that panel-ADF statistic is the second best, and that panel variance and the group- ρ statistics do poorly. We can therefore reasonably conclude that for 9 out of the 14 panels the variables are cointegrated.¹³ For the remaining 5 panels, the variables are found not to have a long-run relationship. These panels include, with one exception, either high-income OECD countries or major oil exporting Middle Eastern countries. The exception is the East Asia and Pacific panel, which includes the biggest growing economy China, being also the most heterogeneous regional panel with respect to development levels of the countries in the panel.

¹²For most of the cases, a model with an intercept is estimated and the variable is found to be I(1). However, in some cases, other specifications such as including a trend or a constant are needed to conclude that the series are I(1). We do not report the results obtained from the LLC and IPS panel unit root tests to conserve space. These and all other unreported results are available in Appendix D.

¹³After conducting a comprehensive survey on the econometrics of nonstationary panels, Baltagi and Kao (2000) indicate that developments in the econometric theory fall short of the demand for empirical studies and in consequence, they acknowledge that "several issues have been resolved but a lot remains to be done" (Baltagi and Kao, 2000, p.35).

1.3.2 Causality results

Based on the cointegration results, for the 9 cointegrated panels we estimated VEC model, while for the remaining 5 panels a VAR model is estimated. The results are presented in Tables 1.3 and 1.4.

Table 1.3 – Causality test results based on the VAR specification

| | Dependent variable | Sources of causation (independent variables) | | | |
|----------------------------|--------------------|----------------------------------------------|--------------|------------|------------|
| | | ΔE | ΔGDP | ΔM | ΔU |
| OECD | ΔE | | 11.590** | 0.639 | 0.697 |
| | ΔGDP | 32.185** | | 0.552 | 1.568 |
| | ΔM | 0.403 | 0.518 | | 2.303 |
| | ΔU | 1.106 | 1.085 | 0.446 | |
| High | ΔE | | 20.413** | 0.649 | 0.250 |
| | ΔGDP | 25.094** | | 0.154 | 5.353 |
| | ΔM | 0.280 | 0.186 | | 0.797 |
| | ΔU | 0.321 | 0.277 | 0.106 | |
| East Asia & Pacific | ΔE | | 15.622** | 2.308 | 18.641** |
| | ΔGDP | 3.636 | | 2.281 | 13.549** |
| | ΔM | 2.834 | 4.383 | | 8.182* |
| | ΔU | 1.168 | 7.527* | 3.604 | |
| Middle East & North Africa | ΔE | | 28.661** | 0.097 | 0.098 |
| | ΔGDP | 3.339 | | 0.003 | 0.048 |
| | ΔM | 1.057 | 0.030 | | 0.020 |
| | ΔU | 0.050 | 0.160 | 0.144 | |
| North America | ΔE | | 1.227 | 0.932 | 0.013 |
| | ΔGDP | 1.535 | | 0.058 | 0.356 |
| | ΔM | 0.897 | 0.066 | | 1.816 |
| | ΔU | 0.711 | 0.646 | 12.896** | |

** , * indicate statistical significance at 1 and 5 percent level of significance, respectively.

Table 1.4 – Causality test results based on the VEC specification

| Dependent variables | Sources of causation (independent variables) | | | | | | | | | | |
|---------------------------|----------------------------------------------|--------------|------------|------------|------------------|---------------------------|-----------------------------|---------------------------|---------------------------|--|--------------------------|
| | Short-run causality | | | | | Long-run causality | | | | | Strong (Joint) causality |
| | ΔE | ΔGDP | ΔM | ΔU | ϵ_{t-1} | $\Delta E/\epsilon_{t-1}$ | $\Delta GDP/\epsilon_{t-1}$ | $\Delta M/\epsilon_{t-1}$ | $\Delta U/\epsilon_{t-1}$ | | |
| Full Panel | ΔE | 61.297** | 1.246 | 0.608 | 112.92** | 191.89** | 114.60** | 113.12** | | | |
| | ΔGDP | 112.55** | 0.365 | 0.631 | 139.39** | 184.02** | 139.88** | 140.87** | | | |
| | ΔM | 0.569 | 0.613 | 0.263 | 0.132 | 0.777 | 0.856 | 0.363 | | | |
| | ΔU | 3.399 | 0.530 | 0.024 | 17.714** | 17.859** | 20.057** | 17.723** | | | |
| Non-OECD | ΔE | 101.73** | 0.031 | 0.641 | 95.422** | 203.25** | 95.482** | 95.766** | | | |
| | ΔGDP | 28.524** | 0.296 | 0.859 | 27.405** | 43.965** | 27.579** | 28.300** | | | |
| | ΔM | 0.639 | 0.148 | 0.453 | 0.922 | 1.375 | 1.104 | 1.452 | | | |
| | ΔU | 2.867 | 0.938 | 0.002 | 13.678** | 14.126** | 14.957** | 13.695** | | | |
| Upper-Middle | ΔE | 4.885 | 0.516 | 6.173* | 9.273** | 14.597** | 9.779* | 17.400** | | | |
| | ΔGDP | 0.515 | 0.162 | 4.417 | 0.096 | 0.610 | 0.269 | 4.754 | | | |
| | ΔM | 1.744 | 1.100 | 1.915 | 5.186* | 6.923 | 6.442 | 6.444 | | | |
| | ΔU | 3.316 | 4.045 | 0.818 | 5.651* | 8.957* | 9.471* | 6.092 | | | |
| Lower-Middle | ΔE | 17.063** | 7.670* | 0.028 | 1.364 | 22.178** | 8.486* | 1.381 | | | |
| | ΔGDP | 4.936 | 0.128 | 2.099 | 9.158** | 17.067** | 9.514* | 14.017** | | | |
| | ΔM | 2.675 | 0.919 | 0.341 | 0.489 | 2.781 | 1.656 | 1.037 | | | |
| | ΔU | 2.581 | 0.986 | 0.141 | 2.728 | 4.429 | 4.412 | 3.036 | | | |
| Low income | ΔE | 18.545** | 42.493** | 3.232 | 0.204 | 18.655** | 42.732** | 3.676 | | | |
| | ΔGDP | 6.350* | 0.650 | 11.055** | 18.190** | 23.939** | 18.881** | 32.483** | | | |
| | ΔM | 1.947 | 0.560 | 0.541 | 1.202 | 3.095 | 1.825 | 1.644 | | | |
| | ΔU | 10.642** | 115.97** | 0.094 | 5.908* | 16.976** | 123.93** | 5.992 | | | |
| Europe & Central Asia | ΔE | 8.628* | 0.833 | 1.125 | 21.828** | 31.736** | 22.856** | 22.407** | | | |
| | ΔGDP | 43.998** | 0.885 | 0.521 | 19.900** | 46.923** | 20.990** | 22.525** | | | |
| | ΔM | 0.219 | 0.349 | 3.692 | 0.321 | 0.533 | 0.723 | 3.719 | | | |
| | ΔU | 1.572 | 0.070 | 2.326 | 2.977 | 3.776 | 3.297 | 5.189 | | | |
| Latin America & Caribbean | ΔE | 92.877** | 0.138 | 3.398 | 21.167** | 153.96** | 21.303** | 23.796** | | | |
| | ΔGDP | 15.559** | 0.034 | 22.926** | 3.071 | 16.792** | 3.168 | 25.511** | | | |
| | ΔM | 0.444 | 0.102 | 0.016 | 0.274 | 0.673 | 0.373 | 0.289 | | | |
| | ΔU | 2.407 | 30.531** | 0.108 | 1.406 | 3.487 | 30.774** | 1.569 | | | |
| South Asia | ΔE | 19.261** | 1.064 | 0.771 | 33.260** | 38.092** | 44.797** | 39.062** | | | |
| | ΔGDP | 10.312** | 2.699 | 7.375* | 6.838** | 18.901* | 8.008* | 11.637** | | | |
| | ΔM | 12.440** | 3.504 | 2.268 | 32.432** | 33.029** | 33.306** | 41.796** | | | |
| | ΔU | 5.965 | 1.272 | 1.296 | 3.021 | 6.058 | 3.187 | 3.024 | | | |
| Sub-Saharan Africa | ΔE | 2.691 | 11.133** | 2.238 | 90.973** | 107.30** | 96.753** | 91.768** | | | |
| | ΔGDP | 3.358 | 0.160 | 1.676 | 30.738** | 30.789** | 31.061** | 31.604** | | | |
| | ΔM | 13.298** | 0.602 | 0.214 | 0.303 | 14.206** | 0.665 | 0.531 | | | |
| | ΔU | 8.919* | 1.112 | 0.114 | 0.022 | 9.201* | 1.120 | 0.141 | | | |

**, * indicate statistical significance at 1 and 5 percent level of significance, respectively.

In most of the panels, bi-directional short-run causality is found between electricity consumption and GDP. This means that electricity consumption and GDP globally stimulate each other in these panels in the short run. On the other hand, when we look at the joint significance of the error correction terms (the significance of which indicates a long-run causality) and short-run parameters γ_{jk} in Eqs. (1.7-1.10), the first remark that should be made is that none of the 9 cointegrated panels supports the neutrality hypothesis between electricity consumption and GDP in the long run. In all panels except for two (low and lower-middle incomes), all variables cause electricity consumption. Nevertheless, the results seem to differ markedly depending on countries' income levels, regional locations and OECD memberships. We will discuss these differences in the next section.

1.4 Discussions

First of all in order to make the empirical findings easier to interpret and to make the discussion more readable, we present the results depicted in Tables 1.3 and 1.4 in a graphical form in Figs. 1.3 and 1.4, in which directions of causality are indicated by arrows.¹⁴ More specifically, for the panels listed next to one of the direction lines, one causality is found; for the panels listed between two direction lines, two causalities are confirmed according to our estimation results.

Consider first Fig. 1.3 that depicts short-run causal links based on both VAR and VEC specifications. While we found the same causal outcomes for the full panel, OECD and non-OECD panels, the results differ with respect to income levels and regions. This confirms our initial suggestion that taking into account regional segmentations and differences in development levels may reveal different causal inferences. For instance, urbanization or electricity net imports are found to be an important factor of electricity consumption in all income levels other than high-income countries, in which urbanization has been stabilized and energy security issues have been addressed in a more rigorous way than other developing countries. For low and lower-middle income

¹⁴Since the main objective of this chapter is to examine the causal links between electricity consumption and three other variables, we do not discuss the results obtained for the interrelationships between these three variables, although they may reveal some interesting insights.

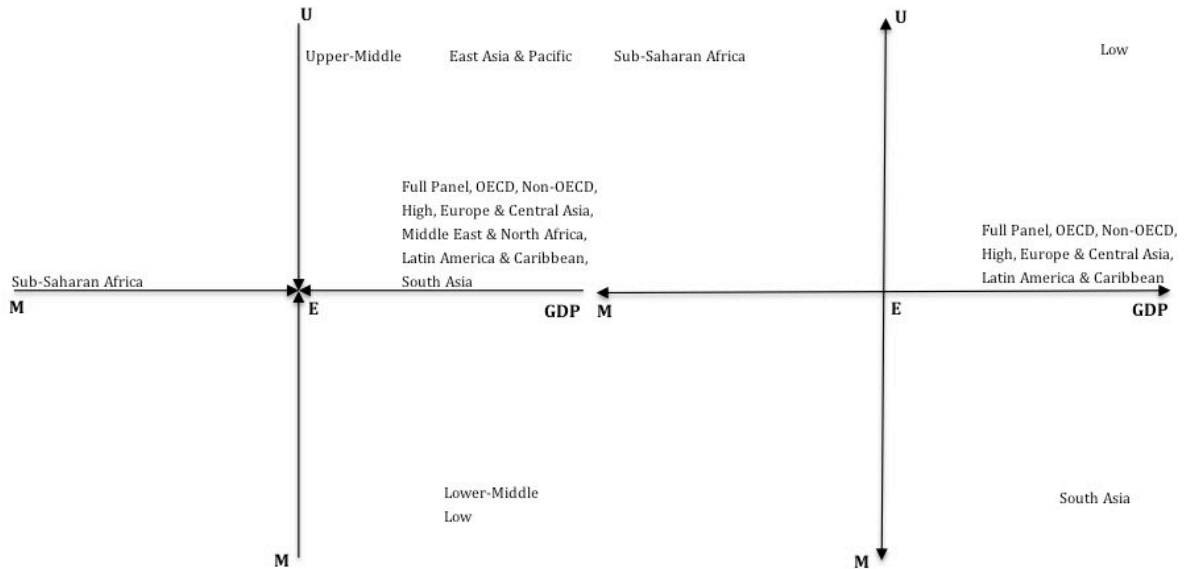


Figure 1.3 – Short-run causal links.

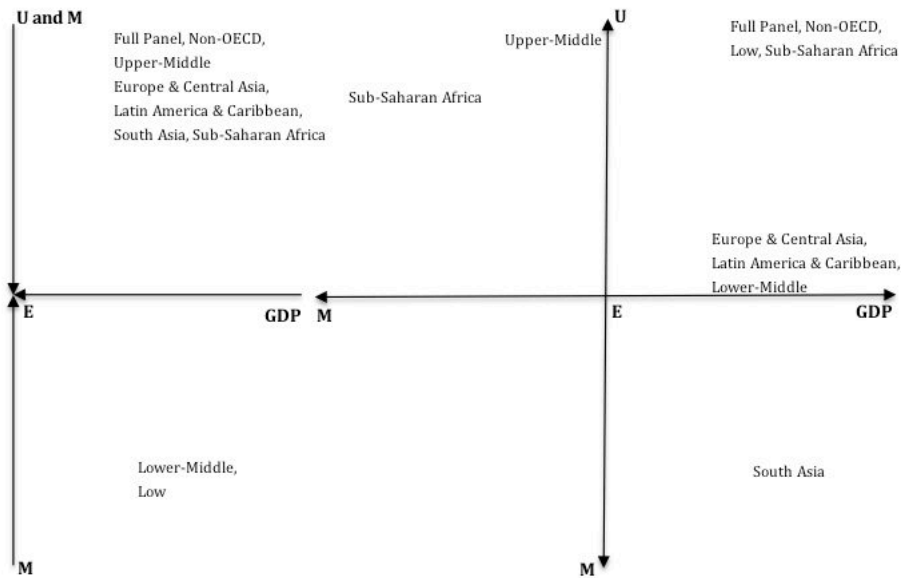


Figure 1.4 – Strong (Joint) causal links

countries, electricity net imports along with GDP cause electricity consumption in a catch-up process, while for the upper-middle income countries the factor that causes

electricity is found to be urbanization. Especially for the case of low-income countries, on the one hand the security of supply is dependent on electricity import and on the other hand, the variations in electricity consumption have an impact on both GDP and urbanization levels. This indicates that electricity shortages (or short-term import volatilities) can be one of the vulnerabilities of low-income economies.

At regional level, in the Sub-Saharan African countries electricity net imports are also of a major concern for the short-run variations in electricity consumption. A further important inference based on this result is that, in this region, electricity consumption causes both urbanization and electricity net imports. As mentioned in Wolde-Rufael (2006), a large number of Africans still does not have access to electricity. According to data provided by International Energy Agency (IEA), in 2009 the average electrification rate in Sub-Saharan Africa is only 30.5%, and it drops to 14.2% in rural areas (IEA, 2011). In such a region, electricity represents therefore the prerequisite of urban agglomeration. In other words, urbanization rates are influenced by electricity access, which is indispensable for urban activities. Another finding for this panel is that while electricity has a causal influence on urbanization and electricity net imports, it does not have a causal effect on GDP in the short run. In this regard, Sub-Saharan Africa is an atypical panel. Note finally that this result validates the neutrality hypothesis between electricity consumption and GDP, which is also the case for upper-middle and North American panels.

For the case of South Asia where over one-fifth of the population lacks access to electricity (IEA, 2011), expanding electricity access causes both economic growth and electricity net import. As we will see below, the same causal links exist in the long run too. This result not only confirms the growth hypothesis for the South Asian countries, but also suggests that the cost of satisfying additional electricity consumption can be found, *ceteris paribus*, in the level of net electricity imports. In line with these arguments, after analyzing the factors affecting the progress of power sector reforms in South Asia, Bhattacharyya (2007) indicated that the future increases in electricity demand of the region will raise the demand for investment in electricity system expansion and concluded that “the uncertainty of reform at the level of institutional environment and institutional arrangements introduces additional risk in conducting business” (Bhattacharyya, 2007, p. 331).

Having discussed the short-run causalities, let us now turn our attention to Fig. 1.4, which displays strong causalities. Compared to the short-run results depicted in Fig. 1.3, it is clear that in the long run urbanization plays a more significant role in electricity consumption. Indeed, rural-to-urban migration process combined with income increases accelerates electricity access among the population of a given country and hence raises the energy consumption. This holds also for the Sub-Saharan panel, for which no causal link is identified in the short run. In fact, from a similar perspective, Onyeji et al. (2012) studied the determinants of electrification in a cross-sectional framework in order to compare the factors affecting the level of electricity access particular to Sub-Saharan countries and other emerging regions, and they found that poverty, corruption, and the share of the population living in rural areas are highly correlated with the access to electricity services. However, the same reasoning does not seem to hold for the two lowest income panels studied in this chapter, i.e. low income and lower-middle income. For these countries in addition to what we mentioned previously for the short-run causalities, it should be further noted that the urbanization process does not follow the same patterns as in other income groups. This point has been discussed by, among others, Popkin (2002) who indicated that “unlike urbanization in the world’s higher-income countries, which is associated with major advances in science, technology, and social organization as well as absorption of large populations, urbanization in low-income countries has not been accompanied by the same level of economic and cultural progress” (Popkin, 2002, p. 124). Our results suggest that this statement applies also for the electricity consumption trends in the lowest income panels.

When we analyze the long-run causalities running from electricity consumption to other variables, we have seen that the results do not vary much with respect to the short-run causalities. Table C.1 in Appendix C, by presenting the major differences among regions, allows us to further explore our results. Correspondingly to the two least urbanized regions in Table C.1, in Fig. 1.4 we have once again Sub-Saharan Africa in the north-west quadrant (in addition to the North-east) and South Asia in the south-east quadrant, that is, the aforementioned arguments hold true also in the long run for these panels. Furthermore, along with the revealed significant impact of urbanization in the short run in East Asia, the development of population composition displays predominantly in Africa and Asia. The two continents, as the most important urbanization

forces, are predicted to account for 86% of all growth in the world's urban population over the next four decades (UN, 2012). However, per capita electricity consumption growth is considerably different in these two regions, e.g. 72% in China as compared to only 3% in Sub-Saharan Africa (DESA, 2011). Our results shed light on one of the underlying reasons that this may be explained by the different causal chains involved between electricity consumption and other variables implicated herein.

Being the three least market-integrated regions, Sub-Saharan Africa, East Asia and Pacific, and South Asia's electricity-GDP nexus presents a significant reliance on electricity net imports. The problem of low electrification rates is mentioned in previous discussions. On top of that, in East Asia, "electricity market integration lags behind other continents where physical electricity cross-border exchanges have increased considerably. In terms of market development, most East Asian countries are yet to develop a national electricity market, let alone the pursuit of regional integration" (Wu et al., 2012, p. 2). On the other hand, in both Latin America and Europe electricity consumption causes solely GDP without an effect on urbanization and electricity net imports. It is evident that for the case of Latin American countries this can be partially explained by the electricity sector reforms started in the 1990s (Mendoza and Pardo, 2010). Seeking to increase competition and efficiency as well as to improve security of supply, Latin America has been heading in the direction of electricity market integration by creating three major blocs: the Southern Cone, the Andean Community and Central America, eventually creating an integrated Latin American electricity exchange, spanning from Mexico to Chile (Ochoa et al., 2013). For the case of European countries, while cross-border transmission system has been put into place gradually, the Green Paper published by European Commission (European Commission, 2006) on 8 March 2006 called for a "common, coherent European Energy Policy" towards the creation of a single electricity market. Moreover, urbanization process in Europe has started much earlier than other countries, and it has already reached a high level of urban development, limiting thus its effect on the variations in electricity consumption over the sample period. Following the same rationale, it is quite logical that North American electricity system does not appear to be constrained by either urbanization or electricity net import, as it is a region with the highest GDP per capita and urban population rates, and "the North American electricity system, which interconnects Canadian and US electricity

markets, is among the most integrated and reliable in the world” (Canadian Electricity Association, 2006). These factors allow North America a relatively stable and secured electricity sector. Finally, according to Table C.1, with moderate urbanization and market integration levels, the average growth of electricity consumption in Middle East and North Africa reaches as high as 4.40% per year. As discussed in Narayan and Smyth (2009), the Middle East as a whole, is highly dependent on revenues from oil exports that are also the main driver to the growth of electricity consumption. Consistent with Squalli (2007), our results indicate that policies for energy conservation can have little or no impact on economic growth in Middle Eastern countries.

Last but not least, it should be pointed out that from the aggregated panels (i.e. full panel and non-OECD panels) we obtained the same results, which cannot be found once regional, and income differences are accounted for. This finding, along with the other findings of the present study, has significant and particular policy implications, which will be discussed in the last section.

1.5 Conclusions and policy implications

1.5.1 Conclusions

In this chapter, we investigated the short- and long-run dynamics between electricity consumption and economic activities, using panel data of per capita electricity consumption and per capita GDP for 160 countries for the period of 1980-2010, accounting for the degree of electricity dependency and the level of urbanization. We found long-run cointegration relationship between electricity consumption and economic growth, implying feedback hypothesis, in the full sample and the majority of the subsamples. In the short run, unidirectional causality running from economic growth to electricity consumption supports conservation hypothesis in East Asia and Pacific, Middle East and North Africa, and lower-middle panels, and the evidence of neutrality is provided in North America, Sub-Saharan Africa and upper-middle income countries. In all panels, our results do not provide support for growth hypothesis. Additionally, the causal relationships among other variables, including urbanization and electricity net import, differ among subsample estimates, depending on panels’ institutional, income and re-

gional differences. That is to say, electricity-growth nexus is highly sensitive to regional differences, countries' income levels, urbanization rates and electricity dependency.

We conclude that GDP and electricity consumption present only short-run or little causality for wealthy economies whereas their relationship tends to be stronger in the long run for low-income economies. Moreover, we found urbanization or electricity net imports to be an important factor of electricity consumption in all income levels except for high-income economies. In other words, electricity dependency appears to be crucial for low and lower-middle income countries, whereas the main driver to electricity consumption is urbanization in upper-middle income countries. Moreover, higher electricity consumption per capita induces urbanization in regions such as Sub-Saharan Africa due to the accessibility to electricity being the rudiment of urban activities. In other emerging economies as East Asia and South Asia, the causality runs in the opposite direction. Furthermore, numerous panel results present significant long-run impacts of electricity dependency on electricity consumption and GDP.

1.5.2 Policy implications

This chapter gives policy implications as follows: (1) electricity conservation policies have to be implemented with great caution as bidirectional causality between electricity consumption and economic growth is found in a number of income groups and geographic regions; (2) successful implementation of a certain reform requires the understanding of the long- or short-run effects on electricity consumption as well as the awareness of the status of urbanization and market integration process; (3) for regions as Sub-Saharan Africa and South Asia, to make electricity accessible to overall economic sectors can improve living standard, accelerate urbanization process and stimulate economic development; (4) regarding the security of supply, the geographical diversification of energy imports from different countries and diversification of energy sources in the energy mix could reduce a given country's energy vulnerability and supply risks (European Commission, 2013), and this is especially important for Africa and Asia; (5) expansion in transmission systems and increase in regional interconnection of electricity, especially in low and lower-middle income countries, call for investments and international cooperation.

Eventually, there is no universal electricity conservation policy that can adapt to every single country, since the global context is rather complex and differs in many aspects. Therefore policymakers should take into account various economic conditions while formulating electricity consumption and conservation policies.

1.5.3 Further research and caveats

Finally, a caveat is in order. Although the aforementioned energy crises fall out of the study period, some other events that have not been taken into account might create structural shifts in the relationship under investigation, which might in turn affect the results. Future research should examine the extent to which possible structural breaks within regions or sub-groups constitute a factor in determining and shaping the electricity-income nexus. Another direction that future work might take is to differentiate between residential and non-residential electricity use instead of using aggregate electricity consumption in order to analyze separately the effects of income variations and urbanization on the electricity use of households and businesses. Such a work would however require, first, availability of data at the disaggregate level for all countries, and then taking into account variables that influence residential electricity use (such as geographic and weather conditions) and commercial electricity consumption (such as the level of industrialization or the share of energy-intensive sectors in total value added).

Bibliography

- [1] Abbas, F., Choudhury, N., 2013. Electricity consumption-economic growth nexus: An aggregated and disaggregated causality analysis in India and Pakistan. *Journal of Policy Modeling*, 35, 538-553.
- [2] Acaravci, A., Ozturk, I., 2010. Electricity consumption-growth nexus: Evidence from panel data for transition countries. *Energy Economics*, 32, 604-608.
- [3] Al-mulali, U., Fereidouni, H.G., Lee, J.Y., 2014. Electricity consumption from renewable and non-renewable sources and economic growth: Evidence from Latin American countries. *Renewable and Sustainable Energy Reviews*, 30, 290-298.
- [4] Apergis, N., Payne, J.E., 2011a. Renewable and non-renewable electricity consumption-growth nexus: Evidence from emerging market economies. *Applied Energy*, 88, 5226-5230.
- [5] Apergis, N., Payne, J.E., 2011b. A dynamic panel study of economic development and the electricity consumption-growth nexus. *Energy Economics*, 33, 770-781.
- [6] Baltagi, B.H., Kao, C., 2000. Nonstationary Panels, Cointegration in Panels and Dynamic Panels: A Survey. Center for Policy Research. Paper 136, 1-44.
- [7] Barsky, R., Kilian, L., 2004. Oil and the macroeconomy since the 1970s. National Bureau of Economic Research.
- [8] Bhattacharyya, S.C., 2007. Power sector reform in South Asia: Why slow and limited so far? *Energy Policy*, 35, 317-332.

- [9] Canadian Electricity Association, 2006. *The Integrated North American Electricity Market, Investment in Electricity Infrastructure and Supply: A North American Concern*.
- [10] Chen, H., Jia, B., Lau, S.S.Y., 2008. Sustainable urban form for Chinese compact cities: Challenges of a rapid urbanized economy. *Habitat International*, 32, 28-40.
- [11] Chen, S.T., Kuo, H.I., Chen, C.C., 2007. The relationship between GDP and electricity consumption in 10 Asian countries. *Energy Policy*, 35, 2611-2621.
- [12] Ciarreta, A., Zarraga, A., 2010. Economic growth-electricity consumption causality in 12 European countries: A dynamic panel data approach. *Energy Policy*, 38, 3790-3796.
- [13] Chontanawat, J., Hunt, L.C., Pierse, R., 2008. Does energy consumption cause economic growth?: Evidence from a systematic study of over 100 countries. *Journal of Policy Modeling*, 30, 209-220.
- [14] Cowan, W.N., Chang, T., Inglesi-Lotz, R., Gupta, R., 2014. The nexus of electricity consumption, economic growth and CO2 emissions in the BRICS countries. *Energy Policy*, 66, 359-368.
- [15] Dickey, D.A., Fuller, W.A., 1979. Distribution of the estimators for autoregressive time series with a unit root. *Journal of the American statistical association*, 74, 427-431.
- [16] Energy Information Administration (EIA), 2013a. Data download.
- [17] Energy Information Administration (EIA), 2013b. *Annual energy outlook 2013 with projections to 2040*. Washington, D.C.
- [18] Engle, R.F., Granger, C.W.J., 1987. Co-integration and error correction: representation, estimation, and testing. *Econometrica*, 55, 251-276.
- [19] European Commission, 2013. *Member states' energy dependence: an indicator-based assessment*, Brussels.

- [20] Ferguson, R., Wilkinson, W., Hill, R., 2000. Electricity use and economic development. *Energy Policy*, 28, 923-934.
- [21] Geweke, J., 1982. Measurement of linear dependence and feedback between multiple time series. *Journal of the American statistical association*, 77(378), 304-313.
- [22] Gnansounou, E., 2008. Assessing the energy vulnerability: Case of industrialised countries. *Energy Policy*, 36, 3734-3744.
- [23] Granger, C.W.J., 1969. Investigating causal relations by econometric models and cross-spectral methods. *Econometrica*, 37, 424- 438.
- [24] Holtedahl, P., Joutz, F.L., 2004. Residential electricity demand in Taiwan. *Energy Economics*, 26, 201-224.
- [25] Hossain, S., 2011. Panel estimation for CO2 emissions, energy consumption, economic growth, trade openness and urbanization of newly industrialized countries. *Energy Policy*, 39, 6991-6999.
- [26] Im, K.S., Pesaran, M.H. Shin, Y, 2003. Testing for unit roots in heterogeneous panels. *Journal of Econometrics*, 115, 53-74.
- [27] International Energy Agency (IEA), 2011. World Energy Outlook-2011 new Electricity access Database, Paris.
- [28] Jobert, T., Karanfil, F., Tykhonenko, A., 2014. Estimating country-specific environmental Kuznets curves from panel data: a Bayesian shrinkage approach. *Applied Economics*, 46, 1449-1464.
- [29] Levin, A., Lin, C.F., James Chu, C.S., 2002. Unit root tests in panel data: asymptotic and finite-sample properties. *Journal of Econometrics*, 108, 1-24.
- [30] Liu, Y., 2009. Exploring the relationship between urbanization and energy consumption in China using ARDL (autoregressive distributed lag) and FDM (factor decomposition model). *Energy*, 34, 1846-1854.

- [31] Mendoza, B.J.R., Pardo, C.S., 2010. Electricity sector reforms in four Latin-American countries and their impact on carbon dioxide emissions and renewable energy. *Energy Policy*, 38, 6755-6766.
- [32] Mishra, V., Smyth, R., Sharma, S., 2009. The energy-GDP nexus: evidence from a panel of pacific island countries. *Resource and Energy Economics*, 31, 210-220.
- [33] Narayan, P.K., Narayan, S., Popp, S., 2010. Does electricity consumption panel Granger cause GDP? A new global evidence. *Applied Energy*, 87, 3294-3298.
- [34] Narayan, P.K., Narayan, S., Prasad, A., 2008. A structural VAR analysis of electricity consumption and real GDP: evidence from the G7 countries. *Energy Policy*, 36, 2765-2769.
- [35] Narayan, P.K., Prasad, A., 2008. Electricity consumption-real GDP causality nexus: Evidence from a bootstrapped causality test for 30 OECD countries. *Energy Policy*, 36, 910-918.
- [36] Narayan, P.K., Smyth, R., 2009. Multivariate granger causality between electricity consumption, exports and GDP: evidence from a panel of Middle Eastern countries. *Energy Policy*, 37, 229-236, 2009.
- [37] Niu, S., Jia, Y., Wang, W., He, R., Hu, L., Liu, Y., 2013. Electricity consumption and human development level: A comparative analysis based on panel data for 50 countries. *International Journal of Electrical Power & Energy Systems*, 53, 338-347.
- [38] Ochoa, C., Dyner, I., Franco, J.C., 2013. Simulating power integration in Latin America to assess challenges, opportunities, and threats. *Energy Policy*, 61, 267-273.
- [39] Onyeji, I., Bazilian, M., Nussbaumer, P., 2012. Contextualizing electricity access in Sub-Saharan Africa. *Energy Sustain. Dev.*, 16, 520-527.
- [40] Organization for Economic Co-operation and Development (OECD), 2010. *The security of energy supply and the contribution of nuclear energy*, Paris.

- [41] Organization for Economic Co-operation and Development (OECD), 2013. List of OECD Member countries.
- [42] O'Neill, B. C., Ren, X., Jiang, L., Dalton, M., 2012. The effect of urbanization on energy use in India and China in the iPETS model. *Energy Economics*, 34, 339-345.
- [43] Onyeji, I., Bazilian, M., Nussbaumer, P., 2012. Contextualizing electricity access in sub-Saharan Africa. *Energy for Sustainable Development*, 16, 520-527.
- [44] Parikh, J., Shukla, V., 1995. Urbanization, energy use and greenhouse effects in economic development: Results from a cross-national study of developing countries. *Global Environmental Change*, 5, 87-103.
- [45] Payne, J.E., 2010. A survey of the electricity consumption-growth literature. *Applied Energy*, 87, 723-731.
- [46] Pedroni, P., 1999. Critical values for cointegration tests in heterogeneous panels with multiple regressors. *Oxford Bulletin of Economics and statistics*, 61, 653-670.
- [47] Pedroni, P., 2004. Panel cointegration: asymptotic and finite sample properties of pooled time series tests with an application to the PPP hypothesis. *Econometric theory*, 20, 597-625.
- [48] Popkin, B., 2002. The dynamics of the dietary transition in the developing world, in *The nutrition transition: diet and disease in the developing world*, Caballero, B., Popkin, B. (Eds), Academic Press, London, 111-128.
- [49] Poumanyong, P., Kaneko, S., 2010. Does urbanization lead to less energy use and lower CO2 emissions? A cross-country analysis. *Ecological Economics*, 70, 434-444.
- [50] Saunoris, J.W., Sheridan, B.J., 2013. The dynamics of sectoral electricity demand for a panel of US states: New evidence on the consumption-growth nexus. *Energy Policy*, 61, 327-336.
- [51] Sims, C. A., 1972. Money, income, and causality. *The American economic review*, 540-552.

- [52] Sims, C. A., 1980. Macroeconomics and reality. *Econometrica: Journal of the Econometric Society*, 1-48.
- [53] Squalli, J., 2007. Electricity consumption and economic growth: bounds and causality analyses of OPEC members. *Energy Economics*, 29, 1192-1205.
- [54] United Nations Development Policy and Analysis Division (DESA), 2011. *Urban Population, Development and the Environment*.
- [55] United Nations (UN), 2012. *Africa and Asia to lead urban population growth in next 40 year*.
- [56] United Nations Conference on trade and Development (UNCTAD), 2013. Handbook of Statistics.
- [57] United Nations Development Policy and Analysis Division (DESA), 2013. *World Economic and Social Survey*.
- [58] Wolde-Rufael. Y., 2006. Electricity consumption and economic growth: a time series experience for 17 African countries. *Energy Policy*, 34, 1106-1114.
- [59] World Bank Africa Infrastructure Country Diagnostics (AICD), 2008. *Underpowered: The State of the Power Sector in Sub-Saharan Africa*.
- [60] Wu, Y., Shi, X., Kimura, F., 2012. *Energy Market Integration in East Asia: Theories, Electricity Sector and Subsidies*. Economic Research Institute for ASEAN and East Asia (ERIA) Research Project Report 2011-2017.
- [61] Yoo, S.H., 2006. The causal relationship between electricity consumption and economic growth in the ASEAN countries. *Energy policy*, 34, 3573-3582.
- [62] Yoo, S.H., Kwak, S.Y., 2010. Electricity consumption and economic growth in seven South American countries. *Energy Policy*, 38, 181-188.

Appendices

Appendix A. Country list

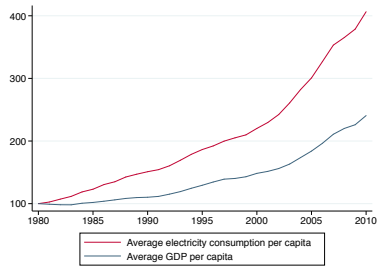
Table A.1: List of countries included in the paper

| Geographic Region | Country | Abbreviation | Income Classification | OECD membership |
|--------------------------|------------------|--------------|-----------------------|-----------------|
| East Asia & Pacific | Australia | AUS | High | OECD member |
| | Japan | JPN | High | OECD member |
| | Korea | KOR | High | OECD member |
| | New Zealand | NZL | High | OECD member |
| | French Polynesia | PYF | High | |
| | Hong Kong, China | HKG | High | |
| | New Caledonia | NCL | High | |
| | Singapore | SGP | High | |
| | Taiwan, China | TWN | High | |
| | China | CHN | Upper middle | |
| | Fiji | FJI | Upper middle | |
| | Malaysia | MYS | Upper middle | |
| | Thailand | THA | Upper middle | |
| | Tonga | TON | Upper middle | |
| | Indonesia | IDN | Lower middle | |
| | Kiribati | KIR | Lower middle | |
| | Laos | LAO | Lower middle | |
| | Mongolia | MNG | Lower middle | |
| | Papua New Guinea | PNG | Lower middle | |
| | Philippines | PHL | Lower middle | |
| | Samoa | WSM | Lower middle | |
| | Vanuatu | VUT | Lower middle | |
| | Vietnam | VNM | Lower middle | |
| Cambodia | KHM | Low | | |
| Dem. People's Rep. Korea | PRK | Low | | |
| Myanmar | MMR | Low | | |
| Europe & Central Asia | Austria | AUT | High | OECD member |
| | Belgium | BEL | High | OECD member |
| | Denmark | DNK | High | OECD member |
| | Finland | FIN | High | OECD member |
| | France | FRA | High | OECD member |
| | Germany | DEU | High | OECD member |
| | Greece | GRC | High | OECD member |
| | Iceland | ISL | High | OECD member |
| | Ireland | IRL | High | OECD member |
| | Italy | ITA | High | OECD member |
| | Luxembourg | LUX | High | OECD member |
| | Netherlands | NLD | High | OECD member |
| | Norway | NOR | High | OECD member |
| | Poland | POL | High | OECD member |
| | Portugal | PRT | High | OECD member |
| | Spain | ESP | High | OECD member |
| | Sweden | SWE | High | OECD member |
| | Switzerland | CHE | High | OECD member |
| | United Kingdom | GBR | High | OECD member |
| | Cyprus | CYP | High | |
| | Greenland | GRL | High | |
| | Hungary | HUN | Upper middle | OECD member |
| | Turkey | TUR | Upper middle | OECD member |
| Albania | ALB | Upper middle | | |
| Bulgaria | BGR | Upper middle | | |
| Romania | ROM | Upper middle | | |

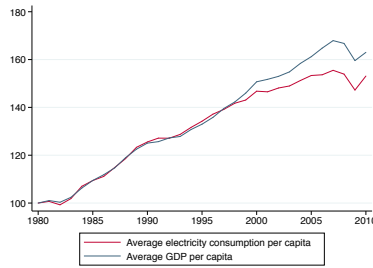
| Geographic Region | Country | Abbreviation | Income Classification | OECD membership |
|----------------------------|----------------------------------|--------------|-----------------------|-----------------|
| Latin America & Caribbean | Chile | CHL | High | OECD member |
| | Antigua and Barbuda | ATG | High | |
| | Bahamas | BHS | High | |
| | Barbados | BRB | High | |
| | Cayman Islands | CYM | High | |
| | Netherlands Antilles | ANT | High | |
| | Saint Kitts and Nevis | KNA | High | |
| | Trinidad and Tobago | TTO | High | |
| | Turks and Caicos Islands | TCA | High | |
| | Uruguay | URY | High | OECD member |
| | Mexico | MEX | Upper middle | |
| | Argentina | ARG | Upper middle | |
| | Belize | BLZ | Upper middle | |
| | Brazil | BRA | Upper middle | |
| | Colombia | COL | Upper middle | |
| | Costa Rica | CRI | Upper middle | |
| | Cuba | CUB | Upper middle | |
| | Dominica | DMA | Upper middle | |
| | Dominican Republic | DOM | Upper middle | |
| | Ecuador | ECU | Upper middle | |
| | Grenada | GRD | Upper middle | |
| | Jamaica | JAM | Upper middle | |
| | Panama | PAN | Upper middle | |
| | Peru | PER | Upper middle | |
| | Saint Lucia | LCA | Upper middle | |
| | Saint Vincent and the Grenadines | VCT | Upper middle | |
| | Suriname | SUR | Upper middle | |
| | Venezuela | VEN | Upper middle | |
| | Bolivia | BOL | Lower middle | |
| | El Salvador | SLV | Lower middle | |
| | Guatemala | GTM | Lower middle | |
| | Guyana | GUY | Lower middle | |
| Honduras | HND | Lower middle | | |
| Nicaragua | NIC | Lower middle | | |
| Paraguay | PRY | Lower middle | | |
| Haiti | HTI | Low | | |
| Middle East & North Africa | Israel | ISR | High | OECD member |
| | Bahrain | BHR | High | |
| | Kuwait | KWT | High | |
| | Malta | MLT | High | |
| | Oman | OMN | High | |
| | Qatar | QAT | High | |
| | Saudi Arabia | SAU | High | |
| | United Arab Emirates | ARE | High | |
| | Algeria | DZA | Upper middle | |
| | Iran | IRN | Upper middle | |
| | Iraq | IRQ | Upper middle | |
| | Jordan | JOR | Upper middle | |
| | Lebanon | LBN | Upper middle | |
| | Libya | LYB | Upper middle | |
| | Tunisia | TUN | Upper middle | |
| | Djibouti | DJI | Lower middle | |
| | Egypt | EGY | Lower middle | |
| Morocco | MAR | Lower middle | | |
| Yemen | YEM | Lower middle | | |
| North America | Canada | CAN | High | OECD member |
| | United States | USA | High | OECD member |
| | Bermuda | BMU | High | |

| Geographic Region | Country | Abbreviation | Income Classification | OECD membership |
|--------------------|--------------------------|--------------|-----------------------|-----------------|
| South Asia | Maldives | MDV | Upper middle | |
| | Bhutan | BTN | Lower middle | |
| | India | IND | Lower middle | |
| | Pakistan | PAK | Lower middle | |
| | Sri Lanka | LKA | Lower middle | |
| | Afghanistan | AFG | Low | |
| | Bangladesh | BGD | Low | |
| | Nepal | NPL | Low | |
| Sub-Saharan Africa | Equatorial Guinea | GNQ | High | |
| | Angola | AGO | Upper middle | |
| | Botswana | BWA | Upper middle | |
| | Gabon | GAB | Upper middle | |
| | Mauritius | MUS | Upper middle | |
| | Seychelles | SYC | Upper middle | |
| | South Africa | ZAF | Upper middle | |
| | Cameroon | CMR | Lower middle | |
| | Cape Verde | CPV | Lower middle | |
| | Congo | COG | Lower middle | |
| | Cote d'Ivoire | CIV | Lower middle | |
| | Ghana | GHA | Lower middle | |
| | Mauritania | MRT | Lower middle | |
| | Nigeria | NGA | Lower middle | |
| | Sao Tome and Principe | STP | Lower middle | |
| | Senegal | SEN | Lower middle | |
| | Swaziland | SWZ | Lower middle | |
| | Zambia | ZMB | Lower middle | |
| | Benin | BEN | Low | |
| | Burkina Faso | BFA | Low | |
| | Burundi | BDI | Low | |
| | Central African Republic | CAF | Low | |
| | Chad | TCD | Low | |
| | Comoros | COM | Low | |
| | DR Congo | ZAR | Low | |
| | Ethiopia | ETH | Low | |
| | Gambia | GMB | Low | |
| | Guinea | GIN | Low | |
| | Guinea-Bissau | GNB | Low | |
| | Kenya | KEN | Low | |
| | Liberia | LBR | Low | |
| | Madagascar | MDG | Low | |
| | Malawi | MWI | Low | |
| | Mali | MLI | Low | |
| Mozambique | MOZ | Low | | |
| Niger | NER | Low | | |
| Rwanda | RWA | Low | | |
| Sierra Leone | SLE | Low | | |
| Somalia | SOM | Low | | |
| Togo | TGO | Low | | |
| Uganda | UGA | Low | | |
| Zimbabwe | ZWE | Low | | |

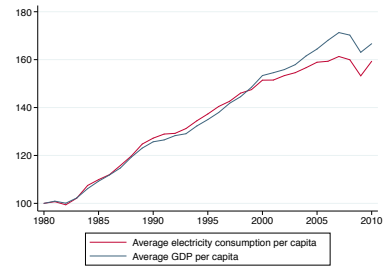
Appendix B. Evolution of the series for all subsamples



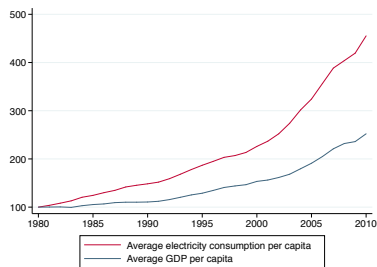
Non-OECD



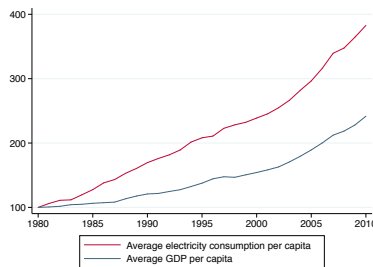
OECD



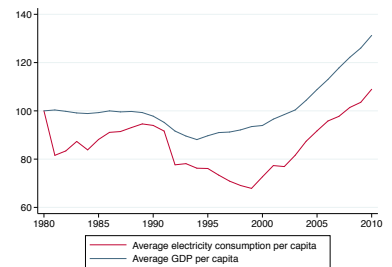
High-income



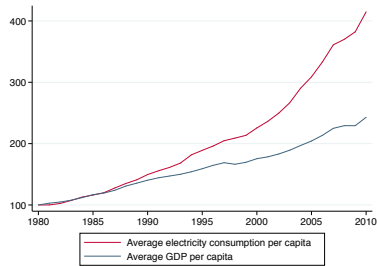
Upper-middle income



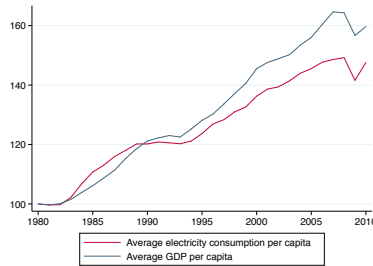
Lower-middle income



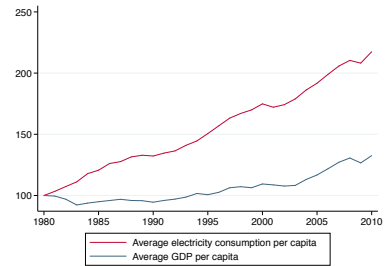
Low income



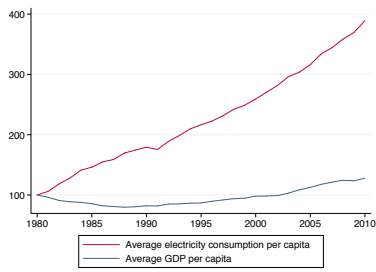
East Asia & Pacific



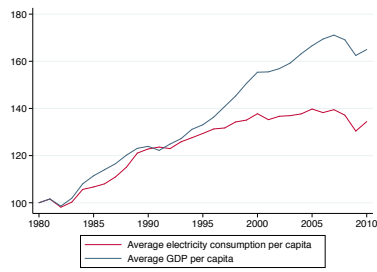
Europe & Central Asia



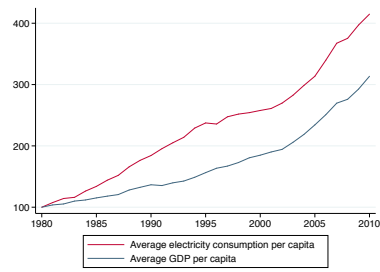
Latin America & Caribbean



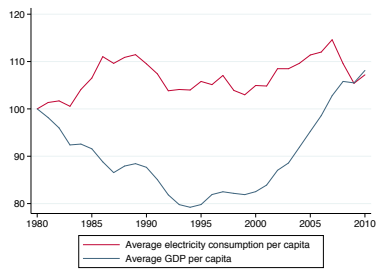
Middle East & North Africa



North America



South Asia



Sub-Saharan Africa

Figure 1.5 – Evolutions of electricity consumption and GDP in the subsamples
Data sources: Authors' calculations based on UNCTAD (2013) and EIA (2013).

Appendix C. Summary of statistics of regional subsets.

Table C.1: Descriptive statistics of regional subsets.

| Region | Electricity consumption | | | GDP | | | Urban share | | Exchange | | Income distribution | |
|----------------------------|-------------------------|----------------|----------|----------------|-------|----------------|-------------|----------------|----------|---------------|---------------------|--|
| | 2010 | Average growth | 2010 | Average growth | 2010 | Average growth | 2010 | Average growth | 2010 | % high income | % low income | |
| North America | 12525.07 | 0.96% | 41000.75 | 1.64% | 81.72 | 0.34% | 73.17 | 100.00% | 0.00% | | | |
| Europe & Central Asia | 5643.56 | 1.27% | 27318.81 | 1.54% | 73.47 | 0.34% | 141.10 | 80.77% | 0.00% | | | |
| East Asia & Pacific | 2823.43 | 4.61% | 5681.73 | 2.91% | 51.86 | 2.03% | 8.08 | 34.62% | 11.54% | | | |
| Latin America & Caribbean | 1889.57 | 2.54% | 5586.74 | 0.91% | 77.88 | 0.66% | 77.44 | 27.78% | 2.78% | | | |
| Middle East & North Africa | 2500.28 | 4.40% | 5131.85 | 0.78% | 62.85 | 0.68% | 31.70 | 42.11% | 0.00% | | | |
| Sub-Saharan Africa | 425.61 | 0.21% | 1045.29 | 0.23% | 36.71 | 1.28% | 14.32 | 2.38% | 57.14% | | | |
| South Asia | 515.42 | 4.60% | 924.43 | 3.72% | 31.01 | 1.08% | 4.10 | 0.00% | 37.50% | | | |

Data sources: Authors' calculations based on UNCTAD (2013), EIA (2013a) and World Bank (2013).

Electricity consumption per capita and electricity trading per capita are measured in kilo watt-hour (kWh) per capita. GDP per capita is measured in US Dollars at 2005 constant prices and exchange rates. Electricity trade per capita is an approximated value for the quantity of electricity of cross-border exchanges. It is calculated by dividing the sum of the absolute values of electricity net imports by two. The calculation is no more than a proxy for within-region electricity trading, relying on the hypothesis that all electricity exchanges take place inside regions. Therefore it does not take into account for cross-regional imports or exports. Hence, these values may be either underestimated or overestimated depending on the net flows of electricity exchanges across regional borders. For this reason, we tend to not calculate the annual growth rates of electricity trading based on these values. The regional means in 2010 of electricity consumption per capita, GDP per capita, share of urban population and electricity trading per capita are weighted by national populations.

Appendix D. Results of unit root tests

Table D.1: Results of unit root tests

| | Series | LLC | | IPS | |
|--------------|--------|--------------------|-----------------------|-------------------|------------|
| | | Level | Difference | Level | Difference |
| Full | EC | 7.03 | -31.88** | 12.11 | -37.24** |
| | GDP | 10.16 | -22.09** | 14.21 | -27.3** |
| | M | 24.38 | 12.78 | 4.8 | -25.93** |
| | U | -2.01* | 1.58 | 4.63 | -4.68** |
| OECD | EC | 10.93 ^c | -28.81** ^c | 13.55 | -34.58** |
| | GDP | 12.72 | -18.95** | 13.35 | -24.14** |
| | M | 27.14 ^t | -26.66** | 7.45 ^t | -19.02** |
| | U | -1.38 | -3.97** | 2.37 | -3.82** |
| Non-OECD | EC | 8.9 | -13.65** | -1.19 | -14** |
| | GDP | -1.22 | -11.97** | 5.03 | -12.8** |
| | M | 1.52 | -13.34** | -1.41 | -18.44** |
| | U | 2.07 ^c | -1.67* ^c | 5.74 | -2.86** |
| high | EC | -3.47** | -20.3** | 1.11 | -20.27** |
| | GDP | -1.43 | -14.11** | 3.88 | -16.2** |
| | M | -1.38 | -16.89** | -2.7** | -18.23** |
| | U | .4 | -3.16** | 2.74 | -6.47** |
| Upper middle | EC | 8.13 | -18.09** | 10 | -20.08** |
| | GDP | 8.48 | -11.38** | 10.49 | -14.07** |
| | M | 3.27 | -13.01** | 3.57 | -15.61** |
| | U | 2.38 ^c | -5.79** | .94 | -18.28** |
| lower middle | EC | 9.4 | -12.15** | 9.2 | -17.6** |
| | GDP | 9.85 | -9.51** | 8.52 | -10.12** |
| | M | .9 | -12.11** | 1.39 | -13.37** |
| | U | -.41 | 2.78 | 2.94 | -1.72* |
| low | EC | 4.44 | -12.92** | 4.75 | -16.27** |
| | GDP | 5.52 | -8.77** | 5.94 | -13.94** |
| | M | 45.16 | 70.63 | 8.55 | -2.91** |
| | U | -.02 | -80.38** | 2.79 | -33.37** |

Table D.1 continued

| | Series | LLC | | IPS | |
|----------------------------|--------|-------------------|-----------------------|-------------------|-----------------------|
| | | Level | Difference | Level | Difference |
| East Asia & Pacific | EC | 6.37 | -6.06** | 8.53 | -9.98** |
| | GDP | 6.93 | -5.68** | 8.4 | -9.69** |
| | M | 56.11 | 93.79 | 5.59 | .65 |
| | U | 2.12 | -80.87** | .22 | -29.79** |
| Europe & Central Asia | EC | -3.41** | -11.77** | -.13 | -12.25** |
| | GDP | -1.84* | -10.72** | 4.19 | -11.75** |
| | M | 0.04 ^t | -10.86** ^t | 2.51 ^t | -14.19** ^t |
| | U | 2.91 | -3.71** | 6.14 | -4.36** |
| Latin America & Caribbean | EC | 4.38 | -19.6** | 8.1 | -20.88** |
| | GDP | 3.15 | -11.22** | 6.09 | -12.37** |
| | M | -.58 | -15.38** | .22 | -15.28** |
| | U | -2.36** | 4.16 | 1.96 | -1.78* |
| Middle East & North Africa | EC | 2.88 | -13.06** | 5.11 | -12.95** |
| | GDP | 3.82 | -8.89** | 3.27 | -9.55** |
| | M | 4.83 | -3.94** | 2.84 | -8.4** |
| | U | .09 | 2.57 | -1.03 | -3.08** |
| North America | EC | -1.71* | -3.09** | -.38 | -3.18** |
| | GDP | -0.6921 | -4.72** | 1.47 | -4.57** |
| | M | -1.9531* | -6.31** | -1.20 | -5.91** |
| | U | -1.1627 | -1.39 | 1.32 | -1.60* |
| South Asia | EC | 7.83 | -6.05** | 9.04 | -7.96** |
| | GDP | 11.91 | -.85 | 13.54 | -1.61 |
| | M | 11.06 | -1.05 | 8.77 | -1.05 |
| | U | 5.42 | -18.23** | 6.82 | -14.63** |
| Sub-Saharan Africa | EC | 2.28 | -20.02** | 2.15 | -22.88** |
| | GDP | 3.31 | -13.7** | 3.79 | -16.74** |
| | M | 4.51 | -11.32** | 3.54 | -12.18** |
| | U | 4.01 ^c | -3.01** ^c | -.65 | -2.54** |

** , * indicate statistical significance at 1 and 5 percent level of significance, respectively. Superscript *c* refers to constant excluded, and superscript *t* refers to constant excluded.

Appendix E. Progress of a competitive retail market

Table E.1: Full retail competition timeline

| Time | Full electricity retail competition |
|------|--------------------------------------------------------------------------------------------------------|
| 1997 | Norway |
| 1998 | The Great Britain; Germany; Finland |
| 1999 | Sweden; New Zealand |
| 2001 | Austria; The Netherlands |
| 2002 | Victoria; New South Wales |
| 2003 | South Australia; Denmark; Spain |
| 2004 | Portugal |
| 2005 | New York; Texas; Ireland |
| 2006 | Czech; Iceland |
| 2007 | France; Luxembourg; Italy Lithuania; Latvia; Slovenia; Poland Greece; Romania; Hungary; Slovakia |
| 2008 | Croatia |
| 2010 | Northern Ireland |

Appendix F. Discussions on alternative causality: Sims (1973) and Geweke (1982)

First, it needs to be pointed out that Sims (1980) was among the first to advocate the use of VAR models. Allowing for a multivariate framework, VAR models extended Granger (1969) and Sims (1973), which were built on bivariate causality tests. Therefore, VAR and VEC models are more recently developed econometric techniques, and they are sufficient for identifications and a validation of causality.

The Sims causality test is based on a characterization of no-causality in a bilateral OLS regression. It is useful for confirming a finding of an unidirectional Granger causality. The idea is the following: if unidirectional causality that X causes Y is found, then we can expect that no future values of X would enter the regression since Y does not cause X . The exogeneity of Y can therefore be verified by regressing Y on the past and

future values of X

$$Y_t = \alpha_0 + \sum_{k=1}^n X_{t-k} + \sum_{l=1}^m X_{t+l} + \eta_t$$

Through a Wald test, the coefficients of future X should be jointly insignificant in order to validate a unidirectional causality running from X to Y . Otherwise, Y cannot be considered to be exogenous, and this unidirectional causality can be challenged. However, even Sims himself acknowledged that a VAR system is more reliable since leaving important factors outside of a bivariate framework can produce misleading results. That being said, we should expect that electricity consumption per capita and GDP per capita are not statistically exogenous for most of the samples since we have found bidirectional causality in the majority of the cases. In Table F.1, the results of the Sims causality between electricity consumption and GDP are presented for all samples. The results are as what we expected for bidirectional causality results. Also, for a lack of causality or unidirectional causality in subsamples such as North America and lower-middle income countries, the results are also consistent with those of the Granger causality in the VAR model. Some inconsistency can be observed in the panels of South Asia and Europe.

Additionally, Geweke (1982) focused on another perspective of causality. He suggested a measure of instantaneous correlation that is directly calculated from the residuals of standard Granger-type causality tests. Instead of relying on a causal relationship between a past X and a current Y , this measure captures an instantaneous feedback between them. The results of instantaneous feedbacks between electricity consumption and GDP per capita, total correlations that is the sum of Geweke and Granger correlations, and the share of Granger influence, are also presented in Table F.1. The share of Granger influence differs significantly across subsamples, but this result has to be interpreted with great caution. As the Geweke test employs a single equation regression, this result is not be equivalent to the results obtained from a VAR or VEC equation system.

Table F.1: Sims and Geweke causality tests

| Test | OECD membership | | | | | Income Level | | | |
|--------------------------------------------|-----------------|---------|----------|---------|----------|--------------|---------|--|--|
| | Full | OECD | Non-OECD | High | U-Middle | L-Middle | Low | | |
| Sims | | | | | | | | | |
| ΔE future $\rightarrow \Delta GDP$ | 64.18** | 11.64** | 47.97** | 15.17** | 6.68** | 12.21** | 2.91* | | |
| ΔGDP future $\rightarrow \Delta E$ | 8.94** | 1.80 | 8.38** | 3.19* | 0.48 | 1.90 | 3.00* | | |
| Instantaneous feedback | 180.22** | 41.12** | 155.05** | 50.79** | 39.32** | 40.33** | 33.13** | | |
| Total correlation | 270.14** | 82.75** | 233.63** | 82.01** | 43.30** | 67.40** | 48.16** | | |
| % Granger causality | 33.29% | 50.31% | 33.63% | 38.07% | 9.19% | 40.16% | 31.21% | | |
| Region | | | | | | | | | |
| Sims | | | | | | | | | |
| ΔE future $\rightarrow \Delta GDP$ | 5.94** | 9.95** | 34.42** | 9.80** | 0.96 | 2.31 | 12.16** | | |
| ΔGDP future $\rightarrow \Delta E$ | 6.70** | 1.37 | 9.03** | 2.22* | 0.80 | 0.82 | 0.87 | | |
| Instantaneous feedback | 102.90** | 27.09** | 0.04 | 44.66** | 10.24* | 0.61 | 27.24** | | |
| Total correlation | 122.49** | 61.07** | 64.70** | 55.14** | 10.91* | 11.21** | 41.52** | | |
| % Granger causality | 15.99% | 55.64% | 99.94% | 19.01% | 6.14% | 94.56% | 34.39% | | |

** , * indicate statistical significance at 1 and 5 percent level of significance, respectively. The Sims causality is a bivariate test with four future and past values. The F-tests shown are for the null hypothesis that all leads variables had zero coefficients. The Geweke causality test includes the exogenous variables urban share and net import.

Chapter 2

Vertical structure and forward contracts

1 *

¹This chapter is based on the working paper: Li, Y., 2014. Vertical Structure and Forward Contracts in Electricity Markets. Department of Research, Ipag Lab.

2.1 Introduction

The electricity sector was historically featured by vertically integrated entities as it had been thought as a natural monopoly industry. Since the 1990s, many countries have successively launched a series of reforms, aiming at introducing competition and enhancing market efficiency in this sector. These reforms entailed a liberalization of generation and retailing through a separation from transmission and distribution, and a creation of an independent system operator to handle grid networks. However, the result of the liberalization is obviously not satisfactory, given the fact that market power has often been traced in liberalized electricity wholesale markets. Generally speaking, since electricity cannot be cost-effectively stored, supply and demand need to be balanced at any moment at any location throughout the grid network. Moreover, short-term electricity demand is almost inelastic in response to wholesale prices. These characteristics clearly differentiate electricity from other commodities, and make electricity markets particularly vulnerable to an exercise of market power. For example. In the United Kingdom, the first European country that proceeded to market reforms, evidence of significant market power has been detected shortly after the liberalization of the electricity market (Green and Newbery, 1992; Wolfram, 1999). Even a decade later, a report of the power sector inquiry published in 2007 by the European Commission identified various shortcomings of liberalized electricity markets, including high concentration from the supply side, which gives scope for exercising market power (EC, 2007). In this context, it has been argued that forward contracts or long-term contracts² can serve as a device of mitigating market power of electricity producers.

The attitude of competition authorities and regulators towards forward contracts have changed over time. They were initially against the use of contracts for the concerns of entry deterrence, as well as of reductions in transparency and liquidity of spot markets. The seminal work by Allaz and Vila (1993) (AV hereafter) was a precursor to show the competitive benefits of forward trading. In their model, individual generators who have signed contracts would gain a first-mover advantage and compete more aggressively in the spot market. Consequently at the equilibrium, a prison's dilemma

²Different types of contracts in terms of delivery requirement, maturity, or signing parties, exist in electricity markets. Importantly, the contracts considered in this chapter is that they are traded before the opening of a spot market, and they are signed between generators and retailers.

outcome arises when every generator does so. As a result, the spot price reduces closer to the competitive level, and spot competition increases with the amount of forward contracting. The AV's results motivated continuous debates about whether contracts enhance competition in electricity markets. Various studies have shown that the answer to this question is controversial: This pro-competitive effect found in AV is very sensitive to variations of some underlined assumptions, although it has become widely accepted to consider forward contracts as a device for market power mitigation when firms are non-cooperative and under Cournot competition. Especially, it has been proven that the pro-competitive effects of contracts can be completely or partially countered by, for instance, a Bertrand-type conjecture (Mahenc and Salanié, 2004), an introduction of retail competition (Green, 2003), or generators' collusive behaviour in the spot or forward market (Powell, 1993).

Besides the aforementioned factors that are likely to vanish the gain in efficiency of forward contracting, this chapter describes a new situation - vertical integration between a generator and a retailer - that may also harm competition. It demonstrates that this effect is achieved via an impact of vertical integration on forward trading. Generally speaking, competition policy admits numerous efficiency gains that can be achieved through a merger between an upstream firm and a downstream firm, such as an elimination of double marginalization and a reduction in free-riding, but anti-competitive concerns arise when one or more merged firms are dominant (Motta, 2004; Tirole, 1988). More precisely, a foreclosure occurs when a vertically integrated upstream firm denies the access of an essential input to other independent downstream firms with an intent of monopolizing the downstream market (Hart et al., 1990; Rey and Tirole, 2006). Following a similar logic, a vertical contract that involves in exclusive dealing could also have an entry-deterrent effect (Aghion and Bolton, 1987). However, the classic theory on the impacts of vertical integration does not seem to fit into electricity wholesale markets. In many countries, electricity wholesale trading is managed by a centralized power exchange, in which all generators are required to submit their expected production before physical delivery.³ As a result, neither efficiency gains nor

³The wholesale market design is adopted in the majority of liberalized electricity markets. Apart from that, some electricity markets take a form of bilateral trading. A typical example is the implementation of the New Electricity Trading Arrangements in 2001 in England, which replaced the obligatory wholesale pool by direct bilateral trade between generators and retailers. The model frame-

potential damages of vertical integration can be reached under such a special market rule, because electricity trading among integrated parties cannot be held exclusively, and no generating firm can withhold an essential facility to deny other retailers' access to electricity. In this context, the effect of vertical mergers and its interactions with forward contracts in wholesale electricity markets need to be especially studied. Its implications on competition policy should also call particular attention from competition authorities.

To our best knowledge, the present chapter is the first attempt to theoretically model the impact of vertical integration between generators and retailers on forward contracting and on competition. More precisely, it examines whether an ownership taken by a retailer in generation assets influences competitive benefits of forward trading. Despite an obvious relevance of the subject, vertical structure of electricity markets has been overlooked by previous research. In many studies, these two instruments have been presumably regarded as perfect substitutes to each other, because both vertical integration and forward contracts creates a vertical link between generators and retailers considering the trading rule of wholesale markets. Therefore, their impacts on competition are also expected to be similar (Aid et al., 2009; Bushnell et al., 2007; Hogan and Meade, 2007). However, what previous literature has not noticed is that their effects on competition are very likely to be different, since a merge or an acquisition can create an amount of reward interdependence between generators and retailers, whereas simply trading forwards would not do so. In other words, an integrated retailer can internalize partially or fully upstream profits, in contrast to an individual retailer, whose profits all come from downstream markets. Therefore, expecting to share upstream profits, an integrated retailer would be interested in rising spot prices by reducing its contracting quantity. In fact, the incentive of trading forward contracts in the case of vertical integration was empirically examined by Gans and Wolak (2007) through a case study. In their findings, the acquisition case in Australia, where the largest retailer took control of 35% stake of an large base-load generation, led to a lower level of forward contracting, and a rise in wholesale prices in the national electricity market after this merger was approved.⁴ Nowadays, changes on market structure and on ownerships are common in the

work developed in this chapter does not suit for a bilateral market.

⁴In 2003, the largest energy retailer Australia Gas Light Company (AGL) intended to acquire a stake as part of a consortium in the largest base-load generator Loy Yang A power station (LYA) in the state of Victoria. On April 1, 2004, AGL took control of a 35% stake of LYA despite that the

energy sector. This Australian case is certainly not alone. In France, the circumstance of one single firm controlling a great extent of both generating and retail business is unlikely to change in a short run, while in the UK, some large retailing and generating firms tend to be more vertically integrated shortly after the initial liberalization of the electricity market. The merger case between the leading operator Endesa and the main generator Iberdrola also attracted attention from the Spanish energy and competition authorities.⁵ Therefore, there is a necessity to study the impact on competition of vertical integration between generators and retailers and to establish the conditions under which adverse effects appear. Up to now, there is little research on this topic. The objective of this chapter is to provide a new theoretical foundation to study the impacts of vertical integration on forward contracts, and further on competition in a wholesale electricity market. This framework is suitable for the market design with a wholesale pooling obligation.

The second novelty of this chapter is to incorporate risk attitudes of both generators and retailers. It identifies two important motives of market participants to trade forwards: strategic behaviour, as shown in AV's model, and hedging. To study the second motive, agents' aversion to risks is important. Since uncertainty in demand often results in fluctuations of spot prices, this drives market participants to seek contracts in order to hedge their perceived risks. It has been argued that risk aversion of retailers would result in an inefficient contract level (Creti et al., 2005). However, the risk attitude of generators has not yet been investigated. Since electricity prices are volatile, it is important to take into account the risk attitude of generators, and this will shed light on upstream risk management. As will be shown in the model, the risk aversion of both generators and retailers plays a deterministic role in the competitive outcomes of vertical integration.

Furthermore, this chapter considers that this vertical integration between a generator and a retailer can be both complete or partial. More precisely, it depicts a situation where a retailer acquires a share in a generating firm and hence earns an additional

Australian competition authority challenged the acquisition at the first place. See Gans and Wolak (2007) for more details.

⁵See decision of the Spanish National Energy Commission (2008): Resolución sobre propuestas de archivo (Expedientes 2600/05 CNE/Empresas sector, 2771/07 Endesa, 2772/07 aceca y 2773/07 Iberdrola).

profit from upstream. Also, following the suggestion of Gans and Wolak (2007), this acquisition is passive, meaning that a retailer can earn a share in the generator's profit but cannot be involved in the generator's bidding or contracting strategies in the spot or forward market. This consideration is suitable for the standard electricity wholesale market design, given the fact that all generators are required to sell their production at a power exchange. The dependence of retail profits on generation profits distinguishes vertical integration from forward contracts.

The rest of the chapter is organized as follows. Section 2.2 reviews the main contributions from related literature. Section 2.3 and Section 2.4 sets up the model foundations and provides analytical results, respectively. Section 2.5 discusses the results and extends the model with conjectural variations. Section 2.6 performs numerical simulations. Finally, Section 2.7 concludes.

2.2 Literature review

Both theoretical and empirical evidence has demonstrated efficiency cannot be achieved in a pure spot market mechanism, because substantial market power and capacity withholding are often documented in a liberalized spot market. As a bidding strategy when demand is inelastic, a pivotal generator, defined as the generator who has the capacity to fulfil the last unit of demand, would have a strong incentive to raise wholesale prices largely above competitive levels (Fabra et al.,2006). This has been evidenced in a variety of empirical studies on oligopolistic competition after the major reform of electricity markets , See, for example, Green and Newbery (1992), Fehr and Harbord (1993), and Wolfram (1999). The common conclusion drawn from these studies is that a high markup on marginal costs and substantial dead weight losses imply insufficiency of a pure spot trading to achieve market efficiency. On that account, forward contracts were advocated as an important tool to alleviate market power in spot markets.

A large amount of literature have been contributed to answer the question whether generators have an incentive to trade forwards and whether forward contracts enhance competition in electricity markets. In line with the motive of arbitrage and hedging, future or forward contracts have been regarded as a commodity derivative to be used against volatile spot prices. The value of the electricity derivative and its fundamental

drivers were investigated by, for example, Bessembinder and Lemmon (2002), Dong and Liu (2007), Lucia and Schwartz (2002), and Pirrong and Jermakyan (1999). On the other hand, departing from these motives, even without demand uncertainty or arbitrage opportunities, the Cournot duopoly model in Allaz and Vila (1993) showed that a generator could gain a Stackelberg position by trading forwards in advance and then compete more aggressively in a spot market. Following the same strategy at the equilibrium by every firm, aggregate output is expanded, and as a result, wholesale prices drop for a purely strategic reason. Especially, they pointed out that when the number of forward trading periods becomes large, the output level approaches to the competitive benchmark.

In what follows, the AV's idea has brought great enthusiasm to examining the effects of electricity forward contracts, but meanwhile their findings have also been challenged by succeeding research. On the one hand, Bonacina and Creti (2010) backed the pro-competitive effect of forward trading with a leader-follower setting, in which consumer surplus always increases with the amount of forward contracts, but a monopolization of the forward market can arrive under Stackelberg competition. In contrast, altering the competition type from Cournot to Bertrand, Mahenc and Salanié suggested that trading forward contracts would be a markup-enhancing strategy due to the complementarity nature of spot competition. Moreover, based on a supply function model initially developed by Meyer and Klemperer (1989), Newbery (1998) supported the efficient use of forward contracts. His findings revealed that incumbents may engage in signing contracts in order to deter entry through lower spot prices, but in this case, different from Aghion and Bolton (1987)'s exclusive-trading model, forward contracts can deter entry only when it is efficient to do so. However, generators' actions in spot markets are more likely to be strategic substitutes instead of complements, and the supply function equilibrium often suffers from the problem of multiple equilibria. Therefore, the main debate about forward contracts has been concentrated on the extensions and the sensibility of the AV framework. Consequently, controversial results are found when altering some of the assumptions in the AV model. The benefits of forward contracts in the stylised case can be diminished in various scenarios, such as, an increase of competition in the retail market (Green, 2004), a collusive behaviour of generators in the spot or forward market (Powell, 1993), non-observability of firms' contracting strategies

(Hughs and Kao, 1997), risk aversion of retailers, or a non-obligatory requirement of the contracting amount (Creti et al., 2005).

Although, from a theoretical point of view, different model settings may yield different competitive outcomes, the efficiency-enhancing advantages of forward trading were confirmed by numerous empirical studies. Setting up a controlled laboratory environment, the works of Brandts et al. (2008), Le Coq and Orzen (2006), and Van Koten and Ortman (2013) found a competition-reinforcing effect of adding a forward round before spot trading starts, and they suggested that forward contracts can be introduced as a behavioural remedy for mergers. Additionally, based on a step-supply function, Wolak (2000, 2007) provided evidence that hedge contracts not only decrease average production costs but also significantly mitigate market power in electricity markets. In line with these claims, acknowledging the efficiency of forward trading, Bushnell (2007) proposed that both forward contracts and a reduction in market concentration can promote competition.

As for vertical structure, much attention has been devoted to the unbundling between generation and networks, but little research makes a clear distinction between forward contracting and vertical integration, despite an increasing number of merger and acquisition cases in the electricity sector (Nilsson, 2005). In a wholesale electricity market, all supply and demand offers are aggregated at a power exchange, vertical integration and forward contracts are often regarded as the same hedging and strategic instrument (Hogan and Meade, 2007). For example, Bushnell et al. (2007) referred both vertical links as vertical arrangements, and there was no difference on their impacts on competition nor interactions between them. However, more recent studies unveiled that electricity retailers could increase retail margins by a means of vertical integration (Giulietti et al., 2010), while seizing upstream generation assets could also produce a profit-dependent mechanism, so that upstream or downstream profits increase with the degree of dependence (Micola et al., 2008). Taking one step further, Aïd et al. (2011) studied the hedging interests of electricity retailers. They pointed out that forwards and vertical integration are in fact imperfect substitutes, and a highly risk averse retailer would prefer to hedge with vertical integration than with forward contracts.

After all, it should be noticed that a theoretical framework that analyzes the impacts

of forward contracts interacted with vertical integration in an electricity wholesale market has not been studied before. In this regard, our analysis fills this gap in literature by bridging two pillars of a vertical relationship between generators and retailers. The idea inherits from the case study in Gans and Wolak's (2007) on a passive acquisition case where an electricity retailer acquires a share in generation assets. Finally, the present chapter contributes to the identification of the important role of a vertically separated market structure, while a forward market is created for the purpose of limiting market participants' ability to exercise market power.

2.3 Model setup

To begin with, we consider that a wholesale mechanism contains a forward market and a spot market, which will open sequentially. In these two upstream markets, duopolistic electricity generators i and j compete à la Cournot. This model is built on the merits of Powell (1999) and Green (2004).

In these wholesale markets, generators and retailers trade electricity in two periods: first, in the forward market, generators commit to sell part of their capacities under a form of forward contracts, and retailers submit their demand for purchasing electricity under contracts; second, in the spot market, generators and retailers know the demand and trade electricity for immediate delivery,⁶ and a spot price is yielded. Furthermore, it is important to mention that the total production of a generator can always cover the amount of forward sales, such that a spot market is always needed. More precisely, the amount of forward sales cannot exceed the total quantity to be produced, because a generator cannot buy back in the spot market.

The only source of uncertainty in this model is the demand in the spot market, and it is unknown to all market participants in the forward trading period. Then, this uncertainty become common knowledge at the stage of spot trading. The reason for that is that demand varies according to many factors, such as weather changes or unplanned economic activities, that cannot be foreseen at the contract stage, and these factors would produce shocks to the demand of the spot market. Accordingly, we

⁶Technically, a spot market is a day-ahead market. Therefore, electricity is traded for a physical delivery one day later.

assume a random shock to the electricity demand, which is projected on the spot price. In this way, the realized spot price is the sum of an expected value of spot prices $E[P_s]$ plus a shock ε with mean 0 and variance σ^2 , such that $P_s = E[P_s] + \varepsilon$. One important setting is that the short-term price uncertainty is revealed only after generators and retailers have signed forward contracts, and this leaves agents' risk aversion to interact with forward decisions at the first stage. We further assume that the variance of spot prices is exogenous to the volume of forward contracting of firm i . This implies that $\frac{\partial \sigma^2}{\partial q_i^f} = 0$. Under the spot-market uncertainty, both generators and retailers are risk averse. Their utilities are modelled by a mean-variance form.

In the downstream electricity market, N retailers set their optimal hedge with forward contracts before buying the rest of the amount in the spot market, and finally, serve final consumers in the retail market. In terms of vertical structure, a retailer can be, to some extent, integrated to a generator. This partial or full integration is realized by an acquisition of generation assets. O'Brien and Salop (2000) illustrated how an undesirable impact on competition arises from a partial ownership. In this regard, a parameter α denotes the degree of vertical integration between a retailer and a generator, varying from 0 to 1. It can also be interpreted as a share in a generating firm held by a retailer. As discussed before, following Gans and Wolak (2007), we also claim that this acquisition is passive, which means that the vertically integrated retailer takes a part of upstream profits but does not participate in the generator's wholesale activities. The market structure described above is illustrated in Fig. 2.1.

In the retail market, we incorporate a market design with a pre-defined retail price. This case refers to the fact that the retail price cannot be adjusted on a short-term basis because it is bounded by supply contracts offered by retailers to their customers. This is a realistic consideration, since retail prices are generally not very flexible. That being said, more words still need to be mentioned about the current status of retail competition in Europe. A series of promotions has been made in order to encourage entry and to facilitate consumers to switch among suppliers for the reason that enhanced retail competition will ensure a pass-through of the achieved efficiency in generation to retail customers (Littlechild, 2009). In France, for example, the law NOME⁷ specifies the right of fringe retailers to source low-cost electricity production from the national

⁷Nouvelle Organisation du Marché de l'Electricité

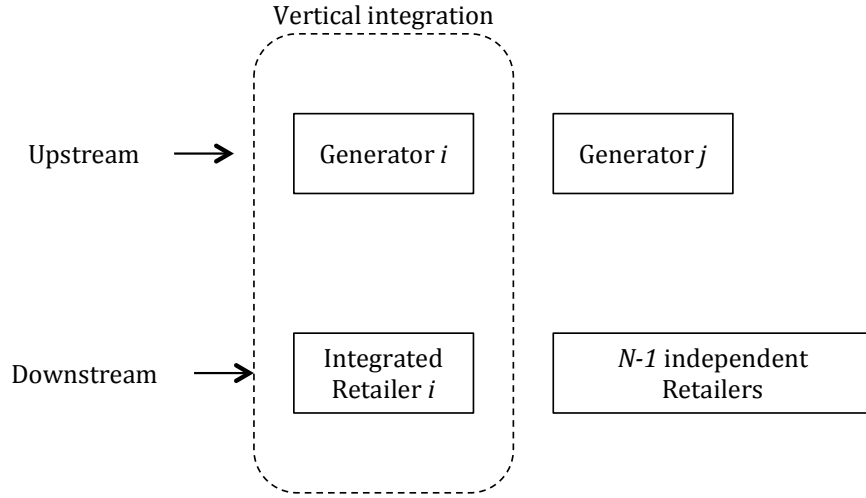
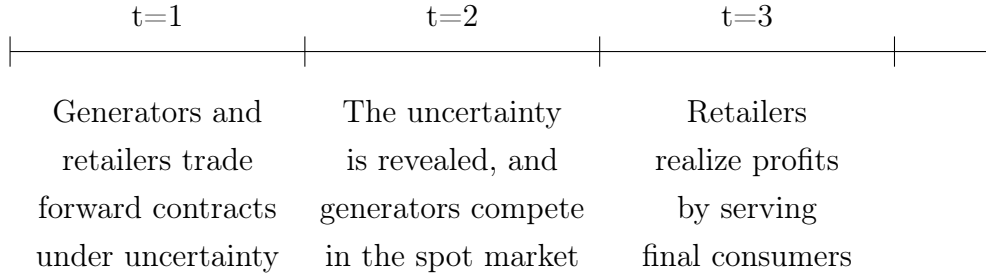


Figure 2.1 – Market structure in the model

incumbent (Creti et al, 2013). Also, final customers often have, for each kilowatt-hour electricity consumed, the choice between a fixed retail price and a menu that combines a peak price and a non-peak price. However, this flexibility is still very limited. Although it has been made possible that consumers in most European countries can freely choose their retail operators (Concettini and Creti, 2014), the effective retail competition has been progressing much more slowly relative to the wholesale competition. The difficulty to achieve a competitive outcome in retail electricity markets is rooted in a lack of load profiling, and retail consumers' inability to respond actively to wholesale price signals (Joskow and Tirole, 2006).⁸ Albeit there is a tendency towards retail competition, a set-up of a fixed price in this model seems to be more reasonable. This is surely, a simplified assumption, but it will allow us to better understand the retailer's interest in vertical integration when he can internalize a part of upstream profits from a generating firm. Plus, embracing more complicated retail pricing schemes will add a margin on the retailer's downstream profit, but this is unlikely to alter his dependence on upstream profits or to change the impact on competition of vertical integration.

⁸Joskow and Tirole (2006) suggested that creating retail competition in electricity markets need load profiling of customers to be measured on a real time basis. Besides that, consumers may not react to real time prices of the spot market because of transaction and monitoring costs, and constraints on physical attributes of their current distribution network.

The timing of this model is shown as below:



As a final note, since the focus of this chapter is the vertical relationship between generation and retailing, possibilities of transmission congestion, capacity constraints, and investments are omitted. A complete notation table can be found in Appendix A.

2.4 Analytical results

2.4.1 Spot market

Starting with generators' strategy in the spot market, we will solve the model backward. At the second stage, generators face a downwards-sloping linear demand curve, $P_s(Q) = a - b(q_i + q_j)$, where q_i and q_j are the quantities produced by generator i and j , respectively. These two generators are identical with a constant marginal cost c . By the time of the spot-market opening, the demand shock is already revealed to them. Therefore, competition between them in the spot market is characterized by a classic Cournot game. Given the amount of output reserved for forward trading q_i^f and q_j^f , the generators maximize their profits, which equal revenues received in the spot market subtracted by production costs. So, the profit of firm i in the spot market is

$$\pi_i^G = (a - b(q_i + q_j))(q_i - q_i^f) - cq_i \quad (2.1)$$

Differentiating this profit function with respect to q_i gives us the best response function of generator i :

$$q_i = \frac{a - bq_j + bq_i^f - c}{2b} \quad (2.2)$$

Similarly, given the output level q_i of generator i , the best response of generator j equals

$$q_j = \frac{a - bq_i + bq_j^f - c}{2b} \quad (2.3)$$

Solving the two equations above, we can obtain the outputs of firm i and j as a function of their forward sales, such that:

$$q_i = \frac{a + 2bq_i^f - bq_j^f - c}{3b} \quad (2.4)$$

$$q_j = \frac{a + 2bq_j^f - bq_i^f - c}{3b} \quad (2.5)$$

Notice that both firms' outputs increase with the amount of their own forward sales, but decrease with that of the rival's. As a consequence, the aggregate market output Q and the realized spot price P_s are respectively

$$Q = \frac{2a + b(q_i^f + q_j^f) - 2c}{3b} \quad (2.6)$$

$$P_s = \frac{a - b(q_i^f + q_j^f) + 2c}{3} \quad (2.7)$$

According to Eqs. (2.6) and (2.7), the aggregate electricity production is an increasing function of the aggregate amount of forward contracts, so that the spot price decreases with the sum of forward sales. This confirms the expected benefit of forward contracts, such that firms behave more aggressively by expanding production, which will lead to lower spot prices.

2.4.2 Forward market

In the forward market, generating firm i maximizes his expected utility, which is given by a mean-variance form under demand uncertainty in the spot market. His expected

utility is

$$E[U_i^G] = E[\pi_i^G] - \frac{1}{2}\lambda^G \text{var}[\pi_i^G] \quad (2.8)$$

$$\begin{aligned} \text{where } E[\pi_i^G] &= (E[P_s] - c)q_i + (P_f - E[P_s])q_i^f \\ \text{var}[\pi_i^G] &= (q_i - q_i^f)^2\sigma^2 \end{aligned}$$

where λ_G denotes the degree of risk aversion of generators, which is assumed to be identical to generators. Without imposing a no-arbitrage condition between the spot and forward markets, we allow for price differences between them, such that a forward premium emerges whenever the forward price P_f exceeds the expected spot price $E[P_s]$. To understand the forward premium, or more generally, the price difference, two factors contribute to the determination of its value: first, a forward price is driven by sale and purchase offers for forward contracts, and this may makes it differ from the expected spot price; second, a forward premium is needed to recompense demand uncertainty and aversion to risks of the market participants. In the following, we insert the results of Eq. (2.4) to rewrite the expected utility for firm i :

$$\begin{aligned} E[U_i^G] &= \frac{(a - bq_i^f - bq_j^f - c)}{3} \frac{(a + 2bq_i^f - bq_j^f - c)}{3b} \\ &\quad + (P_f - E[P_s])q_i^f - \frac{1}{2}\lambda_G\sigma^2 \frac{(a - bq_i^f - bq_j^f - c)^2}{9b^2} \quad (2.9) \end{aligned}$$

As shown by the above equation, the expected utility of generator i is decomposed into three elements: the expected profit from spot-market sales, the expected gain resulted from different forward and spot prices, and a negative term accounting for risk aversion and spot price volatility. Generator i wishes to maximize his utility by setting the quantity of electricity sales reserved to forward contracts in response to the strategy

of his rival j . Thus, the first order condition is given by:

$$\begin{aligned} \frac{\partial E[U_i^G]}{\partial q_i^f} &= \frac{2(a - bq_i^f - bq_j^f - c)}{9} - \frac{(a + 2bq_i^f - bq_j^f - c)}{9} \\ &+ \frac{\partial(P_f - E[P_s])}{\partial q_i^f} q_i^f + (P_f - E[P_s]) + \lambda_G \sigma^2 \frac{(a - bq_i^f - bq_j^f - c)}{9b} \quad (2.10) \\ &= 0 \end{aligned}$$

Here, it should be mentioned that the variation of the total contracting quantity depends also on the assumptions on firms' responses to their rivals. More precisely, firms' belief reflected by conjectural variations, mathematically expressed as $\frac{\partial q_j}{\partial q_i}$, can determine one firm's reaction to a variation in production of the other one. For simplicity, we first consider that generators have a Cournot conjecture at the forward stage, such that $\frac{\partial q_j}{\partial q_i} = 0$. Later, we extend the model by allowing firms to react to the changes in their rivals' strategies, but as will be shown, all main results will hold under the same conditions.

Lemma 1. *For a market under uncertain demand, where symmetric generators with constant marginal costs and mean-variance utility compete à la Cournot as described above, the forward premium yielded from the supply side can be expressed as*

$$P_f - E[P_s] = \frac{q_i^f}{9} \left(4b + \lambda_G \sigma^2 - \frac{9\partial(P_f - E[P_s])}{\partial q_i^f} \right) - \frac{a - c - bq_j^f}{9} \left(1 + \frac{\lambda_G \sigma^2}{b} \right) \quad (2.11)$$

Proof. See appendix B. □

The forward premium of electricity sales is a combination of the contracting quantities from firms i and j . Solving for the optimal level of forward sales of firm i from Eq. (2.11), we obtain the result as described below.

Lemma 2. *For a market of symmetric Cournot generators with constant marginal costs and uncertain demand as described above, given the contracting quantity of generator*

j , the best response of forward trading from firm i is given by

$$q_i^f = \frac{(1 + \frac{\lambda_G \sigma^2}{b})(a - c - bq_j^f) + 9(P_f - E[P_s])}{4b + \lambda_G \sigma^2 - \frac{9\partial(P_f - E[P_s])}{\partial q_i^f}} \quad (2.12)$$

Proof. See appendix B. □

Notice that the quantity of forward contracts in the best response of generator i , not surprisingly, increases with the expected forward premium, and decreases with the sensitiveness of the forward premium relative to a variation in the contracting amount.

2.4.3 Retail market

In the retail market, N symmetric retailers serve final consumers subject to a fixed retail price P_r .⁹ The amount of electricity supplied by each retailer is given and denoted by V , which is a fixed value in the short term. One representative retailer i can be fully or partially integrated with generator i , through a passive acquisition of generation assets. Accordingly, parameter α represents the retailer's share in percentage in generator's profits, such that $0 \leq \alpha \leq 1$. Particularly, $\alpha = 0$ means a complete separation between the retailer and the generator, whereas $\alpha = 1$ indicates a fully vertical integration between them.

In the forward market under demand uncertainty, a retailer i maximizes his expected utility by choosing the optimal amount of electricity purchase with forward contracts, and this quantity is denoted by s_i . The expected profit of an integrated retailer is given by the sum of a revenue from serving final consumers, an extra earning or loss from trading forwards, and a gain from the upstream generator's profit. The retailer also has mean-variance utility, which is adjusted to the price variance and his risk aversion. Therefore, the expected utility function of retailer i is given by

$$E[\pi^R] = (P_r - E[P_s])V + (E[P_s] - P_f)s_i + \alpha((E[P_s] - c)q_i + (P_f - E[P_s])q_i^f) - \frac{1}{2}\lambda_R\sigma^2(V - s_i - \alpha(q_i - q_i^f))^2 \quad (2.13)$$

⁹For simplicity, we do not differentiate between industrial customers and residential customers.

From Eq. (2.13), it follows that vertical integration modifies an integrated retailer's expected utility in two ways: first, through an internalization of an additional profit earned from the upstream markets; second, through a risk reduction effect resulted from the ownership over generation plants. These two aspects are reflected in the last two terms of Eq. (2.13), where the presence of α increases the expected profit at the same time hedges the risk associated with the spot price variance.

Lemma 3. *Assume a pre-defined retail price, demand uncertainty and mean-variance utility as described above. Given the upstream quantities of forward sales q_i^f and q_j^f , the forward premium derived from the demand side is*

$$P_f - E[P_s] = \lambda_R \sigma^2 \left(V - s_i - \alpha \frac{(a - bq_i^f - bq_j^f - c)}{3b} \right) \quad (2.14)$$

Proof. See appendix B. □

Without loss of generality, an expected utility maximizing retailer would fully hedge his retail sales with forward contracts if two conditions were satisfied: $\alpha = 0$, implying that the retailer is not vertically integrated with generation, and $P_f - E[P_s] = 0$, suggesting that the assumption of no-arbitrage opportunity between the forward market and the spot market is imposed. Under these two conditions, we have $V = s_i$. Moreover, an independent risk averse retailer ($\alpha = 0$) would be willing to purchase forward contracts if and only if the forward price exceed expected spot price. Therefore as long as retailers are risk averse, a forward premium is always needed for independent retailers to have an incentive to trade forwards, and this point has also been suggested by Green (2004). In contrast, an integrated retailer does not require a forward premium when the degree of integration is large enough, because he can also benefit from high spot prices. In the case of risk neutrality ($\lambda_R = 0$), the forward premium drops to zero.

Importantly, Eq. (2.14) depicts clearly that forward contracts and vertical integration can be used as substitutes for hedging risks, since both signs before s_i and α are negative. In other words, a decrease in the use of forward contracts can always be compensated by vertical integration, and vice versa. To examine the hedging strategy

of the vertically integrated retailer in a clearer way, we can rewrite Lemma 3 as

$$s_i = V + \frac{E[P_s] - P_f}{\lambda_R \sigma^2} - \alpha \frac{(a - bq_i^f - bq_j^f - c)}{3b} \quad (2.15)$$

The first two terms in Eq. (2.15) on the right hand side are a standard result of the optimal hedge for a risk averse agent, indicating that the optimal amount of hedge contracts is linear in the forward premium and discounted by the degree of risk aversion. The last term in Eq. (2.15) is the contracting quantity that can be reduced due to vertical integration. Therefore, both vertical relationships between retailing and generation provide a hedge to retailers against wholesale price risks. However, as demonstrated by Aïd et al. (2011), they are indeed imperfect hedge substitutes. The degree of substitution between them depends on the coefficient $\frac{(a - bq_i^f - bq_j^f - c)}{3b} = q_i - q_i^f$, which is the amount of production left to be sold in the spot market. In other words, the more electricity can be sold in the spot market, the stronger substitution effect of vertical integration to forward contracts is. Consequently, with vertical integration, the retailer has an incentive to increase upstream profits by trading less forwards. Following this rationale, we add another point to the proposition of Aïd et al. (2011): although vertical integration and forward contracts are imperfectly substitutable hedging instruments, their effects on competition are opposite to each other. In what follows, we consider the competitive outcomes separately in the cases of vertical separation and vertical integration.

The case of vertical separation: $\alpha = 0$

We first build a benchmark case when no firm is merged, and then we use this benchmark result to compare with the result in the vertical integration case. If every retailer is independent from generation, a symmetric downstream structure implies that every retailer will trade electricity under forward contracts at the level of the industry average. Denoting the average industry contracting level as s_0 , we have $s_0 = s_i$. The aggregated forward demand is therefore Ns_0 , and this has to be equal to the aggregate supply of forward contracts $q_i^f + q_j^f$ at the equilibrium, such that $s_0 = \frac{q_i^f + q_j^f}{N}$. This transforms Eq. (2.14) into

$$P_f - E[P_s] = \lambda_R \sigma^2 \left(V - \frac{(q_i^f + q_j^f)}{N} \right) \quad (2.16)$$

Lemma 4. *For a market of symmetric independent generators and retailers with mean-variance utility as described above, the optimal quantity of forward contracts for generator i is*

$$q_{i0}^{f*} = \frac{9\lambda_R\sigma^2V + (a-c)(1 + \frac{\lambda_G\sigma^2}{b})}{5b + 2\lambda_G\sigma^2 + \frac{27}{N}\lambda_R\sigma^2} > 0 \quad (2.17)$$

The optimal hedge with forward contracts for retailer i is

$$s_0 = \frac{18\lambda_R\sigma^2V + 2(a-c)(1 + \frac{\lambda_G\sigma^2}{b})}{5Nb + 2N\lambda_G\sigma^2 + 27\lambda_R\sigma^2} > 0 \quad (2.18)$$

Proof. See appendix B. □

Notice that the optimal amount of forward contracts are positive, and now only depends on exogenous factors: the number of firms in the retail market, the variance of spot prices, and the degree of risk aversion of generators and retailers. The last one confirms our initial motivation to incorporate risk aversion.

Case of vertical integration: $0 < \alpha \leq 1$

We turn to the case where a retailer holds a share of α in the earnings of generator i . To determine the optimal level of forward contracts for an integrated retailer, we need to have a prior belief on the reactions of contracting strategies from other individual retailers. To maintain the traceability of the model, strategic contracting behaviour in the retail market is not included. Thus, we hold the contracting level of the $N - 1$ independent firms unchanged since their vertical structure remains the same as before. However at the equilibrium, the vertically integrated retailer i will adjust the amount of forward contracts due to his structural change. As a result, the optimal forward level of the integrated retailer differs from that of the industry average in the former case. Therefore, s_0 in the current case is the average amount forward contracts held by the $N - 1$ independent retailers. Still, bearing in mind that demand and supply for contracts are equal at the equilibrium, we have $s_rV + (N - 1)s_0V = q_i^f + q_j^f$. The equation of forward premium from the demand side becomes

$$P_f - E[P_s] = \lambda_R\sigma^2(V + (N - 1)s_0 - (q_i^f + q_j^f) - \alpha \frac{(a - bq_i^f - bq_j^f - c)}{3b}) \quad (2.19)$$

Lemma 5. *With the market settings described above, assume vertical integration between a retailer and a generator and its degree α . The optimal amount of forward contracts for generator i is*

$$q_i^{f*} = \frac{9\lambda_R\sigma^2(V + (N - 1)s_0) + (a - c)(1 + \frac{\lambda_G\sigma^2}{b} - \frac{3\alpha\lambda_R\sigma^2}{b})}{5b + 2\lambda_G\sigma^2 + 27\lambda_R\sigma^2(1 - \frac{\alpha}{3})} \quad (2.20)$$

Holding the amount of forward contracts for the independent retailers the same as before, the optimal amount of forward purchase of the vertically integrated retailer i is

$$s_i^* = \frac{18\lambda_R\sigma^2(V + (N - 1)s_0) + 2(a - c)(1 + \frac{\lambda_G\sigma^2}{b} - \frac{3\alpha\lambda_R\sigma^2}{b})}{5b + 2\lambda_G\sigma^2 + 27\lambda_R\sigma^2(1 - \frac{\alpha}{3})} - (N - 1)s_0 \quad (2.21)$$

Proof. See appendix B. □

Eq. (2.20) or Eq. (2.21) show results as follows. Increasing the number of retailers in the downstream market or reducing marginal production costs leads to a rise in the optimal quantity of forward trading, and therefore, this will result in a decrease in the spot price. The optimal level of forward trading depends on the degrees of the risk aversion of both generators and retailers. Moreover, the presence of an impact of vertical integration relies on the retailer's risk aversion, as parameter α is only associated with the retailer's risk attitude.

2.5 Discussions

2.5.1 Impact of vertical integration

In this section, we show that the risk aversion of retailers and generators is essential to determine the impact of vertical integration on forward trading and further on competition.

Proposition 1. *In a market as described before, assume that retailers are risk neutral. Vertical integration between a retailer and a generator does not have an impact on spot prices or on competition. All retailers have the same amount of electricity covered by*

forward contracts, and the optimal coverage for retailer i is

$$s_i = \frac{2(a-c)(1 + \frac{\lambda_G \sigma^2}{b})}{5Nb + 2N\lambda_G \sigma^2} = s_0 \quad (2.22)$$

Proof. See Appendix C. □

Without risk aversion, a retailer does not change his contracting behaviour in forward trading due to vertical integration. As no retailer deviates from the level of industry average, the aggregate amount of forward contracts in the case of vertical integration does not differ from that in the case of vertical separation. Therefore, spot prices remain the same in both cases. Furthermore, recall that the forward premium depends solely on the risk aversion of retailers, so that zero risk aversion implies zero forward premium. As a result, there is no arbitrage opportunity between the spot market and the forward market. The intuition here is that retailers' risk neutrality results in an equalization between the expected spot price and the forward price. At the equilibrium, retailers are indifferent to being integrated or independent, because vertical integration cannot drive the forward price to deviate from the expected spot price. Therefore, there is no extra gain associated with vertical integration.

That being said, in reality, electricity retailers are often required to meet any level of final demand for electricity. This obligation generally exposes them to more risks than generators. Compared with generators, retailers have a very limited ability to raise retail prices. As a consequence, it may make sense to assume that retailers are more risk averse than generators. That means that a retailer should be more eager to seek for a device to hedge. Moreover, note that if generators are also risk neutral (i.e. $\lambda_G = 0$) Eq. (2.22) will reduce to a similar result to AV, such that $s_i = \frac{2(a-c)}{5Nb} = s_0$ and $q_i^f = \frac{a-c}{5b}$.

Next, we need to clarify the influence of generators' risk aversion on the optimal forward sales. Differentiating Eq. (2.20), we obtain $\frac{\partial q_i^{f*}}{\partial \lambda_G} > 0$.

Proposition 2. *For a market with duopolistic Cournot generators with constant marginal costs, the optimal level of forward sales is increasing with generators' risk aversion.*

Proof. See Appendix C. □

This result is rather easy to understand: at the equilibrium, the more risk averse the generators are, the more willing they are to cover their sales with forward contracts. A risk averse generator sells more contracts relative to a risk-neutral generator, such that everything else being equal, the spot price in the former case would be lower than that in the latter case. As a consequence, the fact that generators are risk averse naturally limits their ability to exercise market power in the spot market.

Assume that retailers are risk averse, we now turn to determine how the optimal contracting level varies with respect to the change of vertical integration. As the variations in q_i^{f*} and s_i are monotonous, we will only derive q_i^{f*} in order to examine the impact of vertical integration on the optimal contracting level.

Proposition 3. *Assume risk averse retailers, duopolistic Cournot generators with constant marginal costs, and market settings as described before. A sufficient (but not necessary) condition under which vertical integration leads to an anti-competitive effect is:*

$$\lambda_G < \frac{2b}{\sigma^2} \tag{2.23}$$

Under this condition, we have

$$\frac{\partial q_i^{f*}}{\partial \alpha} < 0 \quad \text{and} \quad \frac{\partial^2 q_i^{f*}}{\partial \alpha^2} < 0$$

Proof. See appendix C. □

Hence, the optimal amount of forward trading is decreasing and concave in the extent of vertical integration. When a generating firm and a retailing firm are vertically integrated, a reduction in forward contracts will lead to higher spot prices. Thus, there is an increase in market power in the spot market, and worse, this inefficiency is reinforced as the degree of vertical integration becomes large. The explanation is that an acquisition of a generating firm becomes a substitute to forward trading for a retailer to hedge risks. Because the vertically integrated retailer earns a part of upstream profits, he has an incentive to increase the spot price, and this strategy is achieved by contracting less. The sufficient condition under which an anti-competitive effect of vertical integration arises is when the generators' risk aversion is not too large. Reckoning with Proposition 2, it implies the situation in which generators' incentive to

trade forwards driven by their risk aversion is not sufficient to overcome the reduction in contracts driven by vertical integration. As a result, vertical integration between a generator and a retailer in an electricity wholesale market, even a passive one, could give rise to unilateral market power.

2.5.2 Conjectural variation

In the previous sections, we have treated the output decision of generator j as given when generator i chooses its contracting strategy. In this section, we relax this assumption of Cournot conjecture at the forward stage and allows for other conjectures. Generally speaking, conjectural variation can characterize the belief that one firm has about the way its competitors may react if it varies its output or price. It captures competitive imperfections and accounts for the incompleteness that may exist in firms' responses. Following Green (2004), we denote conjectural variation $\frac{\partial q_j}{\partial q_i}$ at the forward stage by $\beta \in [-1, 0]$. The two typical cases are: the Cournot conjecture, i.e. $\beta = 0$, where firm i believes no reaction from firm j if he varies his output, and the Bertrand conjecture, i.e. $\beta = -1$, where firm i expects that a change in his output will be completely offset by its competitor's reaction.¹⁰ Therefore, the level of aggregate output depends on the underlined conjectures at the forward stage.

Proposition 4. *Considering conjectural variations of generators in the forward market and other market settings as described before, the optimal amount of forward sales for generator i is*

$$q_{i0}^{f*} = \frac{9\lambda_R\sigma^2V + (1 - 2\beta + \frac{\lambda_G\sigma^2}{b}(1 + \beta))(a - c)}{b(5 - \beta) + 2(1 + \beta)\lambda_G\sigma^2 + \frac{27}{N}\lambda_R\sigma^2} \quad (2.24)$$

An anti-competitive effect of vertical integration arises under the same condition, independently on the type of conjectural variations:

$$\lambda_G < \frac{2b}{\sigma^2}$$

Proof. See Appendix D. □

¹⁰Another case would be $\beta = 1$, in which firms are collusive and behave as joint-profit maximization. We do not discuss it specifically, as general results hold for this case.

When generators at the forward stage have a Bertrand conjecture (i.e. $\beta = -1$), all terms associated with the risk aversion of the generators drop out of Eq. (2.24), so that the optimal quantity of forward trading does not depend on the risk aversion of generators. Consequently, the adverse effect of vertical integration is exacerbated under the Bertrand conjecture, since the constraint on generators' risk aversion is no more needed.

Corollary 1. *The optimal level of forward trading at the equilibrium does not depend on generators' degree of risk aversion if generators have a Bertrand conjecture at the forward stage. In this case, assuming risk averse retailers, vertical integration is always anti-competitive.*

The explanation lies in the nature of the firms' beliefs about their rivals' reactions. When each generator has a Bertrand conjecture, this means that if generator i increases his output, he conjectures that generator j will reduce its output to exactly counteract firm i 's increase. Therefore, total output and spot price remains unchanged. Since the market outcome is independent from single firms' strategy, their risk aversion does not play a role in determining the optimal contract level.

To validate our theoretical results under real market settings, we proceed numerical simulations in the next section.

2.6 Numerical simulations

To calibrate the analytical results, data of hourly spot prices in 2012 are retrieved for the German, French, and Nordic electricity markets (Nord Pool Spot). The sizes of these three markets are similar in terms of trading volumes.¹¹ To avoid influences of outliers and extreme values, we drop the highest 5% and the lowest 5% of the spot prices. A summary statistics is provided in Table 2.1, showing some differences in prices and variance between France and Germany, and Nord Pool Spot. This is due to the fact that the generation mix in the Nordic countries is dominant by hydropower, so that generation costs are lower compared with those in France and Germany. A large

¹¹The annual loads for Germany, France, and Nord Pool in 2012 are 592, 541, and 428 TWh, respectively.

share of hydro generation can also stabilize prices, leading to smaller price variance. As shown by previous empirical studies, the price elasticity of demand for electricity is often found between -1 and -0.1 (see, among others, Borenstein, 2005, Madlener et al., 2014). Particularly, Filippini (2011) estimated the price elasticity of demand to be -0.8 in the Swiss market, while Aubin et al. (1995) found a similar value in assessing the French consumers' response to price signals. We then explore this value to derive the slope of the demand b .¹² Based on the data of the average price P and volume Q , b can be calculated as follows: $b = \frac{dP}{dQ} = \frac{P}{\text{elasticity} \times Q}$. Then, we set the value for the intercept a in the linear demand function to be the sum of the maximal value of the spot price and bQ . Taking Germany as an example, its price and variance values lead us to obtain $b = -0.79$ and $a = 118.61$.

Table 2.1 – Summary statistics of electricity spot prices

| | Mean | Med. | Var. | Max. | Min. | p25 | p75 |
|-----------|-------|-------|--------|-------|-------|-------|-------|
| Germany | 42.81 | 42.12 | 123.70 | 65.10 | 17.43 | 34.87 | 51.92 |
| France | 46.28 | 47.38 | 137.72 | 69.97 | 19.00 | 37.30 | 55.15 |
| Nord Pool | 30.24 | 30.95 | 50.79 | 46.89 | 10.23 | 25.99 | 35.06 |

Summary statistics of mean, median, variance, maximum, minimum, the 25th and 75th percentiles of the spot prices.

Corresponding to the costs of a baseload generation, marginal costs are set to be 25 €/MWh . These costs are based on the evaluation of projected costs by IEA (2010) in the median case for nuclear and coal generation.¹³ The production costs are the sum of fuel, and operating and maintenance (O&M) costs.¹⁴

Table 2.2 lists the number of main retailers in some European countries, showing that most of retail markets in Europe are very concentrated. Besides, there is no evidence that the number of retailers has changed over the period of 2003-2011. We therefore set

¹²Using other values in the range of -1 and -0.1 gives similar results.

¹³The sums of fuel and O&M costs in €/MWh for nuclear and coal plants are 24.07 and 24.23, respectively

¹⁴We could also use the production costs of other technologies, such as, the cost of combined cycle gas turbines (CCGT). IEA (2010) gave an evaluation of 65.6 €/MWh for the production cost of a CCGT. Naturally, a modification on marginal costs needs to be accompanied by an adjustment on the level of final demand. Using production costs of other generation does not change the results of this section.

the number of main retailers at the European average, such that $N = 4$. Each retailer serves final consumers with an amount of $V = 15\text{GWh}$.¹⁵ Notice marginal-cost pricing implies that the total output would equal 86.96GWh ,¹⁶ such that the total demand ($15 \times 4 = 60$) from the four main retailers can be covered. In this and other above-marginal pricing cases, the gap between the total output and main retailers' demand is left to account for the part of downstream fringes.

Table 2.2 – Number of main electricity retailers

| Country | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 |
|---------------|----------|------|------|------|------|------|------|------|------|
| Belgium | 2 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 4 |
| Germany | 4 | 4 | 3 | 3 | 3 | 3 | 3 | 3 | 4 |
| Ireland | 4 | 4 | 5 | 4 | 3 | 4 | 5 | 5 | 4 |
| Greece | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | na |
| Spain | 6 | 6 | 6 | 4 | 3 | 3 | 3 | 4 | 5 |
| France | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| Italy | 3 | 1 | 2 | 3 | 3 | 3 | 2 | 3 | 2 |
| Netherlands | ≥ 3 | 5 | 5 | 5 | 4 | 4 | 4 | 3 | 3 |
| Austria | na | 5 | 6 | 8 | 7 | 6 | 6 | 6 | 6 |
| Poland | na | 3 | 5 | 6 | 6 | 6 | 7 | 7 | 6 |
| Portugal | 1 | 1 | 1 | 1 | 1 | 1 | 2 | 4 | 4 |
| Finland | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| Sweden | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| Norway | 4 | 4 | 4 | na | 5 | 4 | 5 | 5 | 5 |
| United Kindom | 7 | 7 | 7 | 7 | 7 | 7 | 6 | 6 | 6 |
| Average | 3.3 | 3.4 | 3.7 | 3.7 | 3.5 | 3.5 | 3.6 | 3.8 | 4.0 |

Source: Eurostat. A retailer is defined as a main retailer if he sells at least 5% of the total national electricity consumption.

Disregarding the case of risk neutrality of retailers, we start with 0.2 as the risk aversion of retailers. This is similar choice to Green (2004), who assessed retailers' risk aversion by using a "grapes from wine" technique suggested by Grinold (1996). Since the retailers are generally more risk averse than generators, we first study the case when generators are equally risk averse as retailers, and then reduce generators' risk aversion gradually by 25%, 50% and 75%, respectively. In the case of Bertrand conjecture, it is

¹⁵To be consistent with former empirical studies on demand elasticity, we do not replace GWh to MWh. The essential point of the inverse demand function is to represent a price-output relationship.

¹⁶From the demand function $P_s = a - bQ$, we have $Q = \frac{a - P_s}{b} = \frac{118.61 - 25}{0.79}$.

not necessary to perform sensitivity tests on generators' risk aversion, since generators' risk aversion does not enter in firms' forward trading decisions.

Take the price and variance of the German market, Figs. 2.2-2.3 depict the variations in the optimal share of forward sales and in realized spot prices with respect to the change of vertical integration. The figures realized with the French and Nord Pool data are presented in Appendix E. Globally, the share of forward contracts in aggregate output decreases, and the spot price increases as the degree of vertical integration becomes large. This confirms our analytical result that vertical integration gives rise to market power by reducing the amount of forward contracts at the equilibrium. Given the degree of vertical integration between one generator and one retailer, generators' risk aversion has a scale effect on forward trading. The less risk averse the generators are, the lower the forward sale is, and therefore, the higher the spot price is. This corresponds to Proposition 2 and 3, in which generators' risk aversion decreases the optimal amount of forward contracts and anti-competitive effect arises when their risk aversion is below the benchmark level. Particularly the effect of vertical integration in the case of the Bertrand conjecture is much worse compared with its effect in the case of the Cournot conjecture. For example, when the Bertrand conjecture at the forward stage $\beta = -1$, the share of forward sales plunges from 45.55% to 6.27% while the degree of vertical integration varies from 0 to 1. The expected spot price increases from 45.03€/MWh to 54.87€/MWh. This represents a 21.85% increase. Comparing this with the Cournot conjecture case, i.e. $\beta = 0$, in the case of the most risk averse generators, the forward coverage goes down from 60.09% to 52.89%, and the expected price raises from 40.57€/MWh to 42.85€/MWh, which is a 5.62% price increase.

Figs. E.1-E.4 in Appendix E show similar patterns of the impact of vertical integration. To sum up, all analyses uniformly show that an adverse effect of vertical integration can arise through reduced forward trading. The results of numerical simulations validate the analytical results.

2.7 Conclusion

The purpose of this chapter is provide the first theoretical foundation to study the impact of vertical integration between generators and retailers on forward contracting

and on competition in a wholesale electricity market. It examines whether an ownership taken by a retailer in generation assets influences the competitive benefits of forward trading. Vertical integration between generators and retailers in an electricity wholesale market has been little documented by previous literature. However, it worth a special effort to study, and its impact should call competition authorities' attention for two reasons: First, the efficiency gains or competitive damages of vertical integration according to classic economic theories are not suitable for wholesale electricity markets, since all supply and demand offers are centralized; Second, vertical integration and forward contracts have opposite impacts on competition, although they have been regarded as similar hedge instruments. In this context, this study fills the gap in literature and develops a model that is suitable for electricity wholesale market.

As principal results, we find that it is likely for vertically integrated generators and retailers to be less engaged in trading electricity in the form of forward contracts. The results are largely driven by the risk aversion of both retailers and generators. No harm arises if retailers are risk-neutral, otherwise vertical integration raises anti-competitive concerns when generators' risk aversion is below the benchmark level. Through vertical integration, the retailer not only internalizes a part of the generation profits, but also hedges spot price risks. In this sense, vertical integration presents as a natural hedging device for retailers, and therefore it is a substitute to forward contracts when speaking of hedging. On the other hand, the effects of vertical integration and forward trading on competition are mostly different. When the quantity of forward trading decreases with vertical integration, realized spot prices increase, and this gives rise to market power. In this way, the effect of market power mitigation from forward trading is diminished. As secondary results, extending the model to conjectural variations does not alter the main results. The optimal level of forward trading under Bertrand conjecture does not depend on generators' degree of risk aversion. This situation resembles to trading a homogeneous good under price competition which could yield stable price levels, so that the risk attitude of generators does not matter in this case. Finally, numerical simulations show that the damage on competition is more pronounced with a Bertrand conjecture than with a Cournot conjecture.

This study calls for more scrutiny from competition authorities for mergers and acquisitions between electricity generators and retailers, even if these mergers and acqui-

sitions cannot affect generators' bidding behaviour in the spot market. It is important to note that a passive acquisition is already sufficient to give rise to market power in electricity spot markets. As the framework of this study concerns only the wholesale design with a pooling obligation, a relevant work for future research seems to be a study on the impact of vertical integration in a bilateral market. Furthermore, it would also be useful to extend the number of generators to assess the impact brought by a change in market concentration.

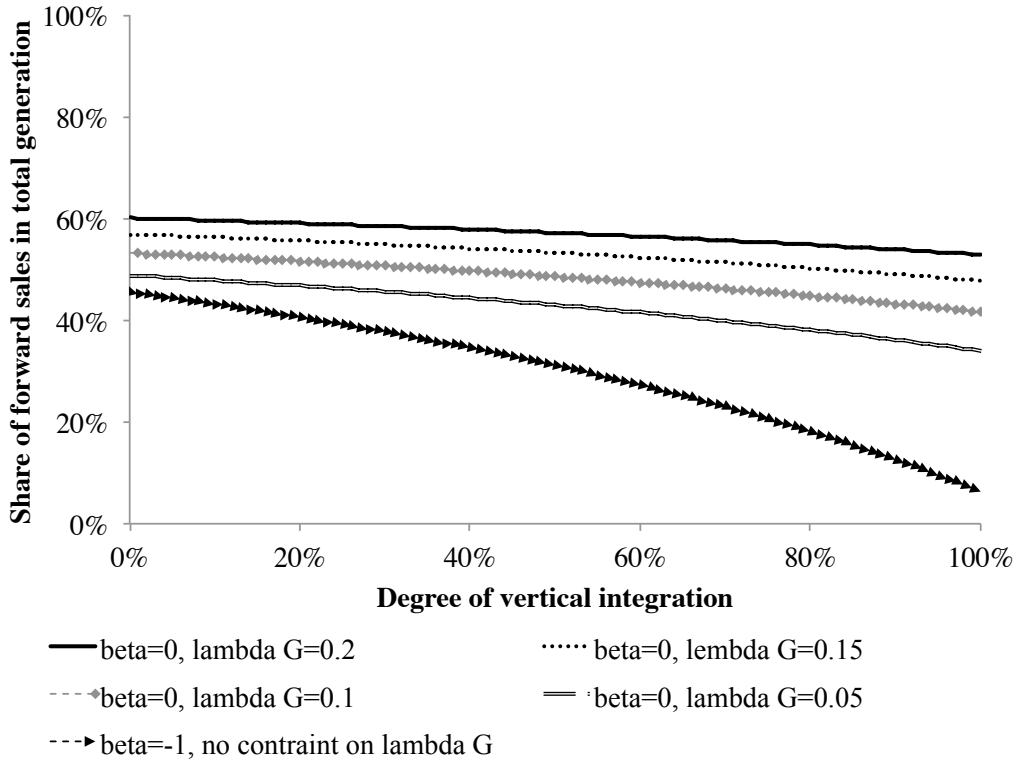


Figure 2.2 – Share of forward sales on degree of vertical integration (Germany)

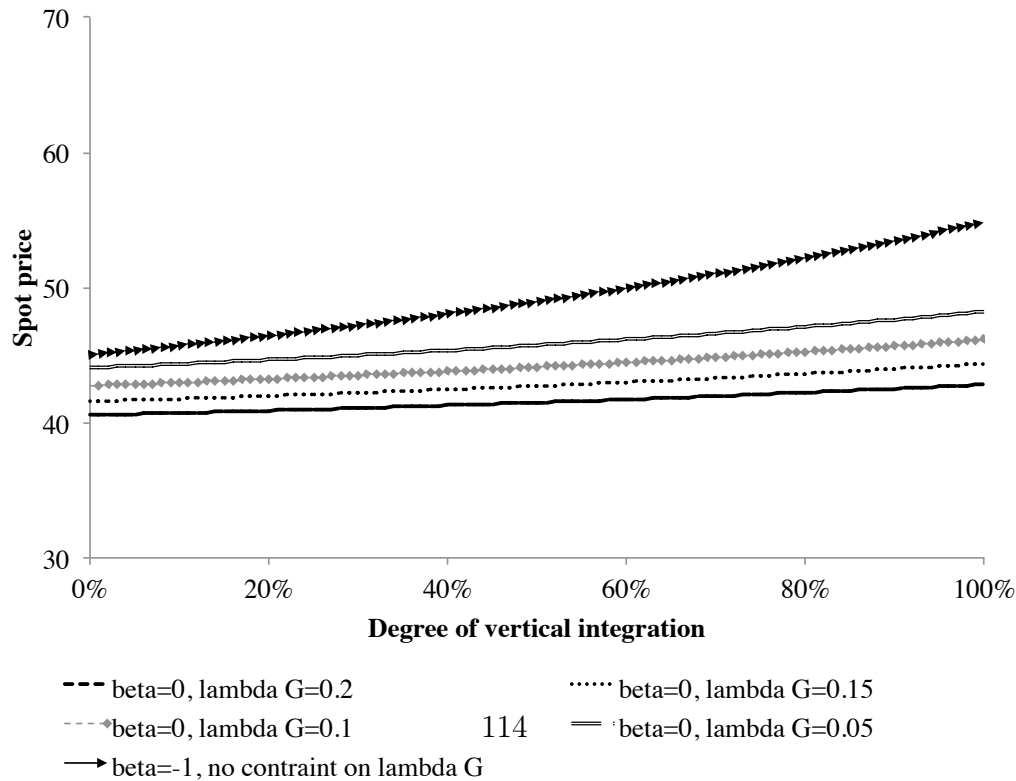


Figure 2.3 – Expected spot prices on degree of vertical integration (Germany)

Bibliography

- [1] Aghion, P., Bolton, P., 1987. Contracts as a Barrier to Entry. *The American economic review*, 388-401.
- [2] Aïd, R., Chemla, G., Porchet, A., Touzi, N., 2011. Hedging and vertical integration in electricity markets. *Management Science*, 57(8), 1438-1452.
- [3] Allaz, B., Vila, J. L., 1993. Cournot Competition, Forward Markets and Efficiency, *Journal of Economic Theory*, 59, 1-16.
- [4] Aubin, C., Fougere, D., Husson, E., Ivaldi, M., 1995. Real-time pricing of electricity for residential customers: Econometric analysis of an experiment. *Journal of Applied Econometrics*, 10(1), 171-191.
- [5] Bessembinder, H., Lemmon, M. L., 2002. Equilibrium pricing and optimal hedging in electricity forward markets. *The Journal of Finance*, 57(3), 1347-1382.
- [6] Bonacina, M., Creti, A., 2010. A note on forward contracts in leader-follower games. *Economic Bulletin*, 30, 1539-1547.
- [7] Borenstein, S., 2005. The long-run efficiency of real-time electricity pricing. *The Energy Journal*, 93-116.
- [8] Brandts, J., Pezanis-Christou, P., Schram, A., 2008. Competition with forward contracts: a laboratory analysis motivated by electricity market design. *The Economic Journal*, 118(525), 192-214.
- [9] Bushnell, J., 2007. Oligopoly equilibria in electricity contract markets. *Journal of Regulatory Economics*, 32(3), 225-245.

- [10] Bushnell, J. B., Mansur, E. T., Saravia, C., 2007. Vertical Arrangements, Market Structure, and Competition An Analysis of Restructured US Electricity Markets. No. w13507, National Bureau of Economic Research.
- [11] Concettini, S., Creti, A., 2014. Liberalization of electricity retailing in Europe: What to do next?. *Energy Studies Review*, 21(1).
- [12] Creti, A., Manca, F., Garante, A., 2005. Mandatory electricity contracts as competitive device. *Autorità Garante della Concorrenza e del Mercato*.
- [13] Creti, A., Pouyet, J., Sanin, M. E., 2013. The Law NOME: Some Implications for the French Electricity Markets. *Journal of Regulatory Economics*, 43, 196-213.
- [14] Crawford, G. S., Crespo, J., Tauchen, H., 2007. Bidding asymmetries in multi-unit auctions: implications of bid function equilibria in the British spot market for electricity. *International Journal of Industrial Organization*, 25(6), 1233-1268.
- [15] Dong, L., Liu, H., 2007. Equilibrium forward contracts on nonstorable commodities in the presence of market power. *Operations Research*, 55(1), 128-145.
- [16] European Commission (EC) DG Competition, 2007. DG Competition Report on Energy Sector Inquiry, Brussels.
- [17] Eurostat, 2013. Number of main electricity generating companies, Brussels.
- [18] Fabra, N., Von der Fehr, N. H., Harbord, D., 2006. Designing electricity auctions. *RAND Journal of Economics*, 23-46.
- [19] Filippini, M., 2011. Short-and long-run time-of-use price elasticities in Swiss residential electricity demand. *Energy Policy*, 39(10), 5811-5817.
- [20] Gans, J. S., Wolak, F., 2012. A comparison of ex ante versus ex post vertical market power: evidence from the electricity supply industry. *Available at SSRN 1288245*.
- [21] Giuliotti, M., Grossi, L., Waterson, M., 2010. Price transmission in the UK electricity market: Was NETA beneficial?. *Energy Economics*, 32(5), 1165-1174.

- [22] Green, R. J., Newbery, D. M., 1992. Competition in the British electricity spot market. *Journal of political economy*, 929-953.
- [23] Green, R., 2004, Retail Competition and Electricity Contracts.
- [24] Grinold, R. C., 1999. Mean-variance and scenario-based approaches to portfolio selection. *The Journal of Portfolio Management*, 25(2), 10-22.
- [25] Hart, O., Tirole, J., Carlton, D. W., Williamson, O. E., 1990. Vertical integration and market foreclosure. *Brookings papers on economic activity*. Microeconomics, 205-286.
- [26] Hogan, S., Meade, R., 2007. Vertical integration and market power in electricity markets.
- [27] Hughes, J. S., Kao, J. L., 1997. Strategic forward contracting and observability. *International Journal of Industrial Organization*, 16(1), 121-133.
- [28] International Energy Agency (IEA), 2010. *Projected Costs of Generating Electricity*, Paris.
- [29] Le Coq, C., Orzen, H., 2006. Do Forward Markets Enhance Competition?: Experimental Evidence. *Journal of Economic Behaviour & Organization*, 61(3), 415-431.
- [30] Littlechild, S., 2009. Retail competition in electricity markets—expectations, outcomes and economics. *Energy Policy*, 37(2), 759-763.
- [31] Lucia, J. J., Schwartz, E. S., 2002. Electricity prices and power derivatives: Evidence from the Nordic power exchange. *Review of derivatives research*, 5(1), 5-50.
- [32] Mahenc, P., Salanié, F., 2004. Softening competition through forward trading. *Journal of Economic Theory*, 116(2), 282-293.
- [33] Klemperer, P. D., Meyer, M. A., 1989. Supply Function Equilibria in Oligopoly under Uncertainty. *Econometrica: Journal of the Econometric Society*, 57, 1243-1277.

- [34] Madlener, R., Bernstein, R., González, M. A. A., 2014. Econometric Estimation of Energy Demand Elasticities.
- [35] Micola, A. R., Banal-Estañol, A., Bunn, D. W., 2008. Incentives and coordination in vertically related energy markets. *Journal of Economic Behavior & Organization*, 67(2), 381-393.
- [36] Motta, M., 2004. *Competition policy: theory and practice*. Cambridge University Press.
- [37] Nilsson, M., 2005. Electric power oligopoly and suspicious minds—a critique of a recently approved merger. *Energy Policy*, 33(15), 2023-2036.
- [38] Newbery, D. M., 1998. Competition, contracts, and entry in the electricity spot market. *The RAND Journal of Economics*, 726-749.
- [39] O’Brien, D. P., Salop, S. C., 2000. Competitive effects of partial ownership: Financial interest and corporate control. *Antitrust Law Journal*, 559-614.
- [40] Pirrong, C., Jermakyan, M., 1999. Valuing power and weather derivatives on a mesh using finite difference methods. *Energy Modelling and the Management of Uncertainty*, 59-69.
- [41] Powell, A., 1993. Trading Forward in an Imperfect Market: The Case of Electricity in Britain”. *The Economic Journal*, 103, 444-453.
- [42] Rey, P., Tirole, J., 2007, A primer on Foreclosure, *Handbook of Industrial Organization*, Vol.3.
- [43] Tirole, J., 1988. *The theory of industrial organization*. MIT press.
- [44] Van Koten, S., Ortmann, A., 2013. Structural versus behavioral remedies in the deregulation of electricity markets: An experimental investigation motivated by policy concerns. *European Economic Review*, 64, 256-265.
- [45] Wolak, F. A., 2000. An Empirical Analysis of the Impact of Hedge Contracts on Bidding Behavior in a Competitive Electricity Market. *International Economic Journal*, 14(2), 1-39.

- [46] Wolak, F. A., 2007. Quantifying the supply-side benefits from forward contracting in wholesale electricity markets. *Journal of Applied Econometrics*, 22(7), 1179-1209.
- [47] Wolfram, C. D., 1999. Measuring duopoly power in the British electricity spot market. *American Economic Review*, 805-826.

Appendices

Appendix A. List of notations

Table A.1: List of notations

| Notation | Description |
|---------------------|-------------------------------------------------|
| α | degree of vertical integration |
| λ_G | risk aversion of generators |
| λ_R | risk aversion of retailers |
| q_i (q_j) | electricity production of generator i (j) |
| q_i^f (q_j^f) | forward sale of generator i (j) |
| P_s | realized spot price |
| σ^2 | variance of spot prices |
| s_i | forward purchase of retailer i |
| V | end-users' demand for a retailer |
| N | number of retailers |
| β | conjectural variation of generators |

Appendix B. Proofs of Lemma 1-5

Proof of Lemma 1

Rearranging Eq. (2.10), we have

$$-(P_f - E[P_s]) = \frac{(a - 4bq_i^f - bq_j^f - c)}{9} + \frac{\partial(P_f - E[P_s])}{\partial q_i^f} q_i^f + \lambda_G \sigma^2 \frac{(a - bq_i^f - bq_j^f - c)}{9b}$$

Separating q_i^f from the rest of the equation reduces the equation to

$$-(P_f - E[P_s]) = -\frac{q_i^f}{9} \left(4b + \lambda_G \sigma^2 - \frac{9\partial(P_f - E[P_s])}{\partial q_i^f} \right) + \frac{a - c - bq_j^f}{9} + \frac{\lambda_G \sigma^2 (a - c - bq_j^f)}{9b}$$

This can be further reduced to Eq. (2.11)

Proof of Lemma 2

Rearranging Eq. (2.11) for q_i^f , we obtain

$$q_i^f = \frac{(1 + \frac{\lambda_G \sigma^2}{b})(a - c - bq_j^f) + 9(P_f - E[P_s])}{4b + \lambda_G \sigma^2 - \frac{9\partial(P_f - E[P_s])}{\partial q_i^f}}$$

Proof of Lemma 3

Differentiating the retailer's expected utility in Eq. (2.13) with respect to the amount of forward trading, the first order condition is given by

$$\frac{\partial E[U_i^R]}{\partial s_i} = (E[P_s] - P_f) + \lambda_R \sigma^2 (V - s_i - \alpha(q_i - q_i^f)) = 0$$

Moving the forward premium to the left hand side and substituting q_i with Eq. (2.4), we have

$$\begin{aligned} P_f - E[P_s] &= \lambda_R \sigma^2 (V - s_i - \alpha(q_i - q_i^f)) \\ &= \lambda_R \sigma^2 \left(V - s_i - \alpha \frac{(a - bq_i^f - bq_j^f - c)}{3b} \right) \end{aligned}$$

Proof of Lemma 4

From Eq. (2.16), we have $\frac{\partial(P_f - E[P_s])}{\partial q_i^f} = -\frac{1}{N} \lambda_R \sigma^2$. Equalizing the two equations of forward premium Eqs. (2.11) and (2.16), we solve for the optimal amount of forward contracts of generator i .

$$\lambda_R \sigma^2 \left(V - \frac{(q_i^f + q_j^f)}{N} \right) = \frac{q_i^f}{9} \left(4b + \lambda_G \sigma^2 - \frac{9\partial(P_f - E[P_s])}{\partial q_i^f} \right) - \frac{a - c - bq_j^f}{9} \left(1 + \frac{\lambda_G \sigma^2}{b} \right)$$

Searching for a symmetric solution for generators i , the equation can be reduced to

$$\begin{aligned} \lambda_R \sigma^2 \left(V - \frac{2q_i^f}{N} \right) &= \frac{q_i^f}{9} \left(5b + 2\lambda_G \sigma^2 + \frac{9\lambda_R \sigma^2}{N} \right) - \frac{a - c}{9} \left(1 + \frac{\lambda_G \sigma^2}{b} \right) \\ 9\lambda_R \sigma^2 V - (a - c) \left(1 + \frac{\lambda_G \sigma^2}{b} \right) &= q_i^f \left(5b + 2\lambda_G \sigma^2 + \frac{27\lambda_R \sigma^2}{N} \right) \end{aligned}$$

which leads to

$$q_{i0}^{f*} = \frac{9\lambda_R\sigma^2V - (a - c)\left(1 + \frac{\lambda_G\sigma^2}{b}\right)}{\left(5b + 2\lambda_G\sigma^2 + \frac{27\lambda_R\sigma^2}{N}\right)}$$

It follows that the symmetric solution of forward hedge for an independent retailer is $s_0 = \frac{2q_{i0}^{f*}}{N}$.

Proof of Lemma 5

Similar to the proof of Lemma 4, forward premiums from both generator and retailer sides are equalized. For the vertically integrated retailer, his coverage in contract is $s_i = q_i^f + q_j^f - (N - 1)s_0V$. Differentiating Eq. (2.16) with respect to q_i^f gives us: $\frac{\partial(P_f - E[P_s])}{\partial q_i^f} = -(1 - \frac{\alpha}{3})\lambda_R\sigma^2$. Implementing the above results in Eq. (2.16), we have:

$$\begin{aligned} & \lambda_R\sigma^2(V - (q_i^f + q_j^f) + (N - 1)s_0 - \alpha\frac{(a - bq_i^f - bq_j^f - c)}{3b}) \\ &= \frac{q_i^f}{9}\left(4b + \lambda_G\sigma^2 - \frac{9\partial(P_f - E[P_s])}{\partial q_i^f}\right) - \frac{a - c - bq_j^f}{9}\left(1 + \frac{\lambda_G\sigma^2}{b}\right) \end{aligned}$$

This reduces to a symmetric solution as in Eq. (2.20).

Appendix C. Proofs of Proposition

Proof of Proposition 1

Assuming that the risk aversion of retailers $\lambda_R = 0$, Eq. (2.21) reduces to

$$s_i = \frac{2(a - c)\left(1 + \frac{\lambda_G\sigma^2}{b}\right)}{5b + 2\lambda_G\sigma^2} - (N - 1)s_0 \quad (2.25)$$

Eq. (2.18) becomes

$$s_0 = \frac{2(a - c)\left(1 + \frac{\lambda_G\sigma^2}{b}\right)}{5Nb + 2N\lambda_G\sigma^2} \quad (2.26)$$

Replacing s_0 by the above equation in s_i , we have

$$s_0 = \frac{2(a-c)(1 + \frac{\lambda_G \sigma^2}{b})}{5Nb + 2N\lambda_G \sigma^2} = s_i \quad (2.27)$$

Proof of Proposition 2

For the convenience of notations, we denote

$$\begin{aligned} A &= \frac{a-c}{b} & R &= \lambda_R \sigma^2 & G &= \lambda_R \sigma^2; \\ B &= 5b + 2\lambda_G \sigma^2 + 27\lambda_R \sigma^2 (1 - \frac{\alpha}{3}) \end{aligned}$$

Differentiating q_i^{f*} with respect to λ_G gives

$$\begin{aligned} \frac{\partial q_i^{f*}}{\partial \alpha} &= \frac{A\sigma^2(5b + 2G + 27R(1 - \frac{\alpha}{3})) - 2\sigma^2(9R(V + (N-1)s_o) + A(b + G - 3R\alpha))}{B^2} \\ \frac{\partial q_i^{f*}}{\partial \alpha} &= \frac{\sigma^2(3Ab + 6\alpha R + 27RA(1 - \frac{\alpha}{3}) - 18R(V + (N-1)s_o))}{B^2} \\ &\geq \frac{\sigma^2(3Ab + 6\alpha R + 18RA - 18R(V + (N-1)s_o))}{B^2} \quad \text{since } \alpha \leq 1 \\ &= \frac{\sigma^2(3Ab + 6\alpha R + 18R(A - (V + (N-1)s_o)))}{B^2} \\ &> 0 \end{aligned}$$

The last inequality is followed by the condition $A - (V + (N-1)s_o) \geq 0$. This will be discussed together with the proof of Proposition 3.

Proof of Proposition 3

The same expressions as before are denoted by A , R , G and B . Differentiating q_i^{f*} with respect to α gives

$$\frac{\partial q_i^{f*}}{\partial \alpha} = \frac{-3AR(5b + 2G + 27R(1 - \frac{\alpha}{3})) + 9R(9R(V + (N-1)s_o) + A(b + G - 3R\alpha))}{B^2}$$

After a few rearrangements, this reduces to

$$\frac{\partial q_i^{f*}}{\partial \alpha} = \frac{3R(27R(V + (N - 1)s_o - A) + A(G - 2b))}{B^2}$$

Because $B > 0$, $R > 0$, and $A > 0$, the terms that we need to consider is $V + (N - 1)s_o - A$ and $G - 2b$. Therefore, rewrite $V + (N - 1)s_o - A$ as $V + (N - 1)s_o - \frac{(a-c)}{b} < 0$. Then, it is straightforward that

$$V + (N - 1)s_o - \frac{(a - c)}{b} \leq 0, \quad \text{if } s_o \leq V$$

since $\frac{a-c}{b} \geq Q = NV \geq V + (N - 1)s_o$. This is implied by the condition where the maximal total electricity supply, yielded when the spot price equals the marginal cost, should be larger than the aggregate output whenever the spot price exceeds the marginal cost. Then, it is larger than the sum of $N - 1$ retailers' forward purchase and one retailer's downstream supply.

If retailers can over contract, meaning that it is possible that $s_o > V$, we can prove $V + (N - 1)s_o - \frac{(a-c)}{b}$ will be still be below zero by contradiction. $V + (N - 1)s_o - \frac{(a-c)}{b} > 0$ meaning that

$$\begin{aligned} (N - 1)s_o &> \frac{(a - c)}{b} - V > \frac{(a - c)}{b} - \frac{(a - c)}{Nb} = \frac{(N - 1)(a - c)}{Nb} \\ Ns_o &> \frac{(a - c)}{b} \end{aligned}$$

Then, this implies that at the equilibrium in the vertical separation case, the aggregate quantity of forward contracts of generators is

$$q_i^f + q_j^f = Ns_o > \frac{(a - c)}{b} > q_i + q_j$$

This is contradictory since generators cannot sell more electricity under contracts than the quantity that they produce. This would imply that generators have to buy back electricity from the spot market, and this is not allowed. As a result, we have

$$V + (N - 1)s_o - \frac{(a - c)}{b} \leq 0$$

which does not depend on retailers' contracting strategy.

Furthermore, $G - 2b$ is negative if $\lambda_G \sigma^2 - 2b < 0$. This yields

$$\lambda_G < \frac{2b}{\sigma^2}$$

As a consequence, $\lambda_G < \frac{2b}{\sigma^2}$ is a sufficient condition for $\frac{\partial q_i^{f*}}{\partial \alpha} < 0$.

Following this result, the second derivative is

$$\begin{aligned} \frac{\partial^2 q_i^{f*}}{\partial \alpha^2} &= \frac{(-2)(-9R\alpha)3R(27R(V + (N-1)s_o - A) + A(G - 2b))}{B^3} \\ &= \frac{54R^2\alpha(27R(V + (N-1)s_o - A) + A(G - 2b))}{B^3} < 0 \end{aligned}$$

if the same condition holds.

Appendix D. Extension with conjectural variations

With conjectural variations, the first order condition of Eq. (2.9) is modified to

$$\begin{aligned} \frac{\partial E[U_i^G]}{\partial q_i^f} &= \frac{2(a - bq_i^f - bq_j^f - c)}{9} - \frac{(a + 2bq_i^f - bq_j^f - c)}{9} \\ &+ \frac{\partial(P_f - E[P_s])}{\partial q_i^f} q_i^f + (P_f - E[P_s]) + \lambda_G \sigma^2 \frac{(a - bq_i^f - bq_j^f - c)}{9b} \\ &+ \frac{\partial q_j}{\partial q_i} \left(- \frac{(a - bq_i^f - bq_j^f - c)}{9} - \frac{(a + 2bq_i^f - bq_j^f - c)}{9} \right. \\ &\left. + \frac{\partial(P_f - E[P_s])}{\partial q_i^f} q_i^f + \lambda_G \sigma^2 \frac{(a - bq_i^f - bq_j^f - c)}{9b} \right) \\ &= 0 \end{aligned}$$

Solving for the forward premium from the upstream, for generator i :

$$P_f - E[P_s] = \frac{q_i}{9} \left((4+\beta)b + (1+\beta)(\lambda_G \sigma^2 - \frac{9\partial(P_f - E[P_s])}{\partial q_i^f}) - \frac{(a - c - bq_j^f)}{9} (1 - 2\beta + (1+\beta)\frac{\lambda_G \sigma^2}{b}) \right)$$

The forward premium equation from the downstream remains the same. When $\alpha =$

0, we solve the optimal level of contract sales of generator i under vertical separation:

$$q_{i0}^{f*} = \frac{9\lambda_R\sigma^2V + (1 - 2\beta + \frac{\lambda_G\sigma^2}{b}(1 + \beta))(a - c)}{b(5 - \beta) + 2(1 + \beta)\lambda_G\sigma^2 + \frac{27}{N}\lambda_R\sigma^2}$$

When $0 < \alpha \leq 1$, we have

$$q_i^{f*} = \frac{9\lambda_R\sigma^2(V + (N - 1)s_0V) + (1 - 2\beta + \frac{\lambda_G\sigma^2}{b}(1 + \beta) - \frac{3\alpha\lambda_R\sigma^2}{b})(a - c)}{b(5 - \beta) + 2(1 + \beta)\lambda_G\sigma^2 + 9(3 + \beta)(1 - \frac{\alpha}{3})\lambda_R\sigma^2}$$

If generators have a Bertrand conjecture at the forward stage (i.e. $\beta = -1$), this reduces to

$$q_{iB}^{f*} = \frac{9\lambda_R\sigma^2(V + (N - 1)s_0V) + (3 - \frac{3\alpha\lambda_R\sigma^2}{b})(a - c)}{6b + 18(1 - \frac{\alpha}{3})\lambda_R\sigma^2}$$

With conjectural variations in generators' behaviour, the same condition holds:

$$\frac{\partial q_i^{f*}}{\partial \alpha} < 0 \quad \text{and} \quad \frac{\partial^2 q_i^f}{\partial \alpha^2} < 0 \quad \text{if} \quad \lambda_G < \frac{2b}{\sigma^2}$$

Deriving q_i^{f*} with respect to α , after a few rearrangements, we obtain:

$$\frac{\partial q_i^f}{\partial \alpha} = \frac{-27\lambda_R^2\sigma^4(3 + \beta)(\frac{a-c}{b} - (V + (N - 1)s_0) - 3\lambda_R\sigma^2(a - c)(1 + \beta)^2(2 - \frac{\lambda_G\sigma^2}{b}))}{\left(b(5 - \beta) + 2(1 + \beta)\lambda_G\sigma^2 + 9(3 + \beta)(1 - \frac{\alpha}{3})\lambda_R\sigma^2\right)^2} < 0$$

given that $\frac{a-c}{b} \geq Q > V + (N - 1)\bar{s}V$. The first term of the nominator is negative since $\frac{a-c}{b} \geq Q > V + (N - 1)\bar{s}V$. Consequently, as long as $\frac{\lambda_G\sigma^2}{b} < 2$, the second term of the nominator is negative. Thus the result $\frac{\partial q_i^f}{\partial \alpha} < 0$ is assured.

Under the same condition, the second derivative equal to:

$$\frac{\partial^2 q_i^f}{\partial \alpha^2} = -\frac{6(\beta + 3)[27\lambda_R^2\sigma^4(3 + \beta)(\frac{a-c}{b} - (V + (N - 1)\bar{s}V)) + 3\lambda_R\sigma^2(a - c)(1 + \beta)^2(2 - \frac{\lambda_G\sigma^2}{b})]}{\left(b(5 - \beta) + 2(1 + \beta)\lambda_G\sigma^2 + 9(3 + \beta)(1 - \frac{\alpha}{3})\lambda_R\sigma^2\right)^3} < 0$$

Appendix E. Results of simulations for France and Nord Pool

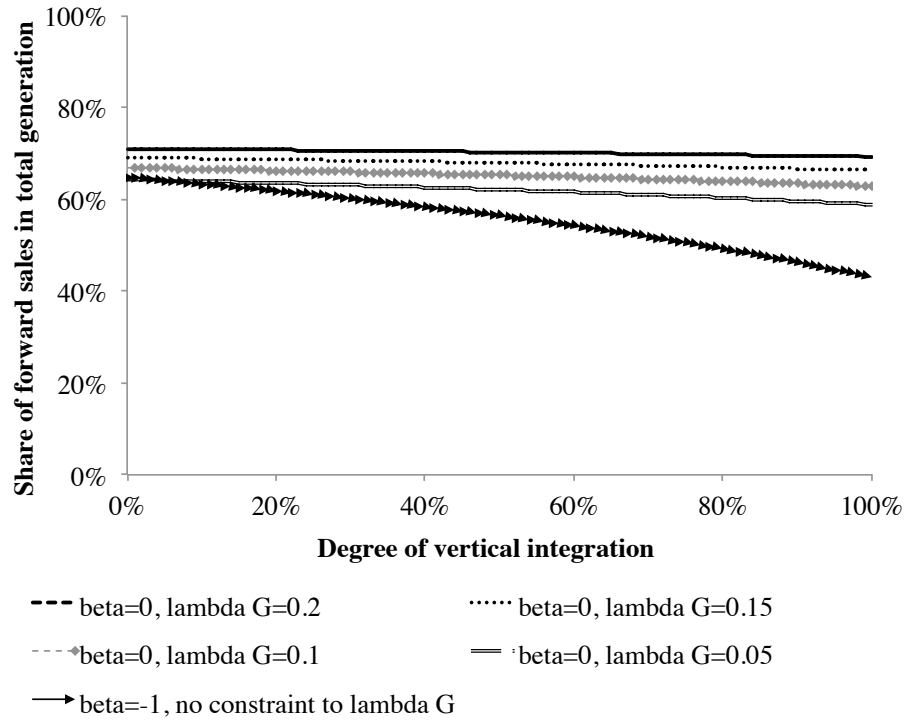


Figure E.1: Share of forward sales on degree of vertical integration (Nord Pool)

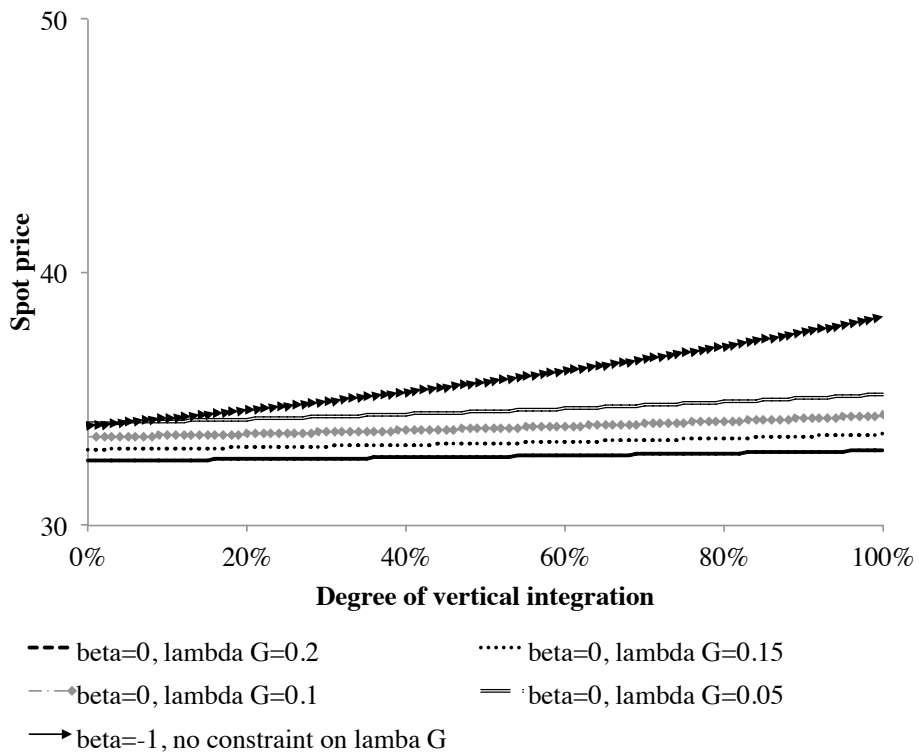


Figure E.2: Expected spot prices on degree of vertical integration (Nord Pool)

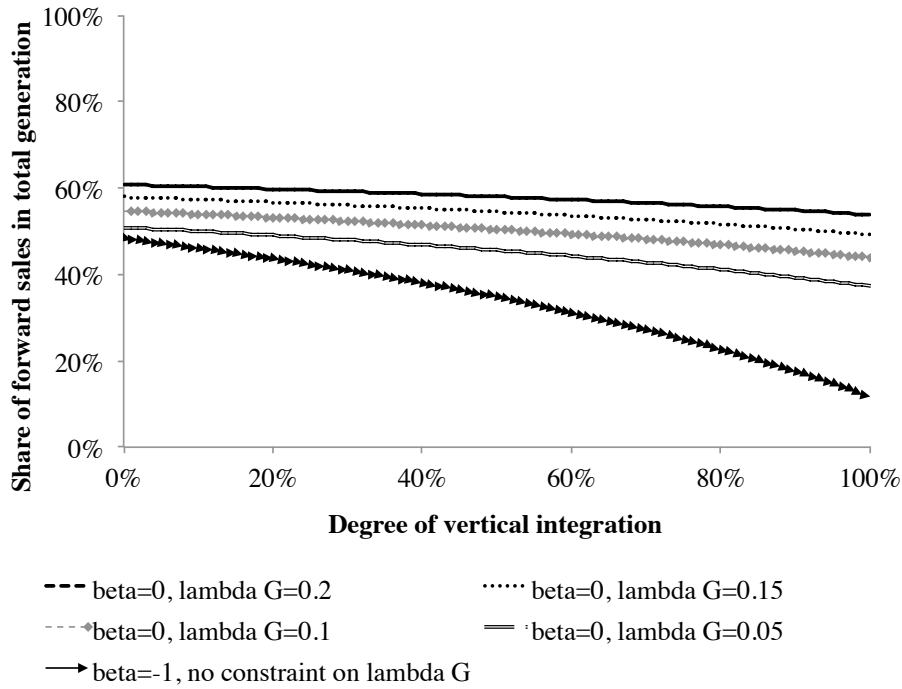


Figure E.3: Share of forward sales on degree of vertical integration (France)

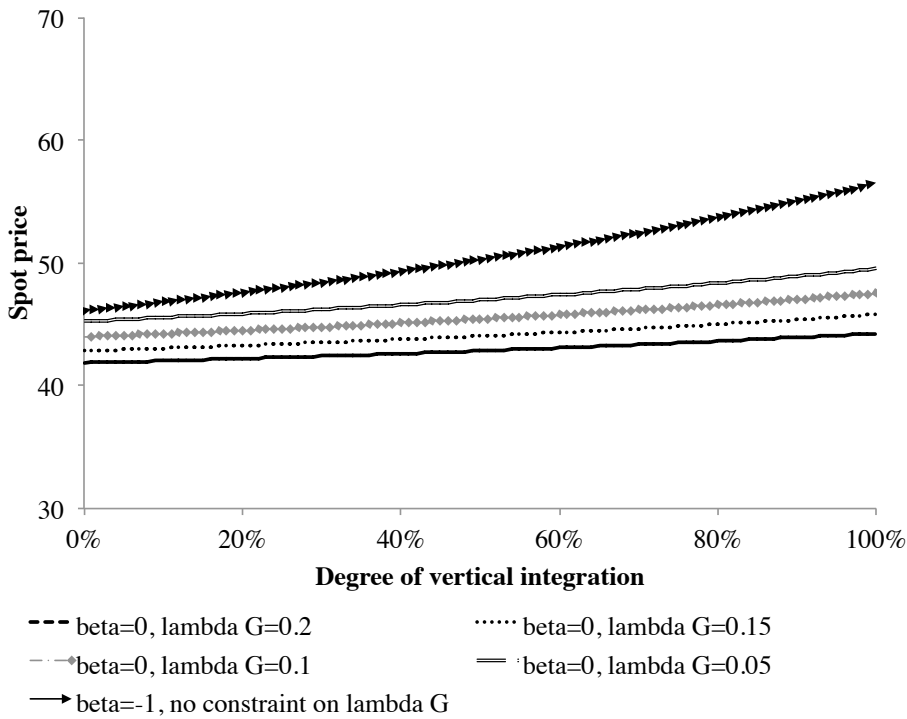


Figure E.4: Expected spot prices on degree of vertical integration (France)

Chapter 3

Day-ahead short-term price and volatility dynamics with rising wind power

¹ *

¹This chapter is based on the working paper: Li, Y., 2015. Revisiting short-term price and volatility dynamics in day-ahead electricity markets with rising wind power. Chaire European Electricity Markets.

3.1 Introduction

Since the last decade, the share of wind power in electricity generation has been rapidly increasing and foreseen to continuously increase due to its positive environmental and economic externalities. For instance in Europe, in order to ensure the transition from fossil fuel-based power generation to renewable energy sources (RES), the European Commission aims at raising the share of RES in final energy consumption to 20% by 2020 (EC, 2009) and to at least 27% by 2030 (EC, 2014). Consequently, the rise of wind energy supply brings various challenges to current energy systems since wind power generation is highly variable and poorly predictable, and these characteristics have great influences on the evolution of electricity day-ahead markets (i.e. spot markets). Therefore, to understand these new aspects of price and volatility dynamics calls for a reexamination of electricity day-ahead markets in consideration of high penetration of wind power in generation mix.

Among numerous countries with well-developed wind power, early deregulation and investments have contributed to today's considerable share of wind power in Denmark (IRENA, 2013). The Nordic wholesale electricity market, namely Nord Pool Spot, has been a liberalized system with relatively long history. For these reasons, Denmark and the Nord Pool day-ahead market appear to be an ideal case to study the dynamics of the wholesale electricity market under the impacts of wind generation. Using hourly data from Denmark and Nord Pool Spot, the present chapter has two purposes. First, it examines the impacts of wind power generation and electricity cross-border exchanges on price and volatility dynamics in the Nordic electricity day-ahead market. Purposely, a generalized conditional heteroskedasticity (GARCH) process is applied to analyze price volatility with exogenous market drivers. One of the novelties of this chapter is that as a particular fundamental of the Nord Pool market, cross-border exchanges are further distinguished into market coupling flows between Nord Pool and other spot markets, and net import flows to Denmark from Sweden and Norway. The latter term is of importance to capture the technical substitution between wind power and hydropower in the abovementioned Nordic countries. Second, it models electricity prices and concentrates on price and volatility evolutions driven by both market-specific fundamentals and electricity price series' specific characteristics. As many scholars have pointed out that modeling electricity prices and volatility is not a trivial task due to electricity's idiosyncrasies such as non-storability and constrained transmission capacities, the resulting electricity prices often show pronounced seasonality at multiple levels, high and asymmetric time-varying volatility and short-lived jumps and spikes (Knittel and Roberts, 2005; Mugele et al., 2005; Liu and

Shi, 2013). The forecasting performance of purely statistical models is inadequate, partially due to the occurrences of abrupt price fluctuations that can only be pre-indicated by relevant exogenous variables rather than historical price patterns (Karakatsani and Bunn, 2008). Given the intermittent nature of wind power, these fluctuations can be especially related to or exaggerated by the variations of wind power generation. Therefore, an adequate prediction model should take account all together of seasonality, market-fundamental drivers and proper statistical distributions of the price series.

The contributions of the present chapter are at least trifold. First, it explores the specific characteristics of the Nord Pool market and gives an insight into the impacts of wind power, cross-border coupling and internal power exchanges on the day-ahead market. In this regard, it accentuates the roles of market fundamentals in price and volatility determination, suggesting that the analysis of price evolutions should be hence market-specific. Particularly for the first time in econometric literature, the Nordic-specific balancing effect between the Danish wind export and the Norwegian and Swedish hydro import is modeled. As will be shown later, the interactions between these two generating technologies result in stabilizing the day-ahead prices, proving the importance of this specific market driver to Nord Pool. Regarding the impact of wind penetration on spot prices in an economic sense, high level of wind supply in the system is expected to dampen wholesale prices on average in electricity spot markets. This phenomenon is commonly recognized as a merit order effect. It occurs when high penetration of wind power pushes some conventional plants with high marginal costs out of a generating profile and thus depresses market prices, as wind power is dispatched prior to other technologies when it is at disposal given its advantages from nearly zero marginal costs and subsidy programs. Furthermore, there may be congestions in transmission system, especially during the periods when wind penetration is high. This will lead to a separation of different areas in one single market, additionally lowering spot prices in congested regions (EWEA, 2010). In contrast to the impacts on wholesale prices, the influences of the development of wind generation on price volatility have received less attention. As the amount of electricity generated from wind power is highly dependent on meteorological conditions, wind power can be considered as exogenous shocks to electricity supply. For periods when wind power output is large, wholesale prices will be low, even negative for some extreme cases.² However, for periods when wind output is low, flexible plants must be activated to satisfy end-users' demand.³

²Negative spot prices are observed infrequently in European Energy Exchange (EEX), mainly covering the French and German markets, as a result of the growth of electricity production from RES generators, whose revenues are ensured by fixed tariffs. For more details, see Fanone et al. (2013).

³See for example, Delarue et al. (2011) apply a portfolio theory model to show that deployment of

Associated high ramping and marginal costs as well as exercise of market power may create price spikes that may reach a higher level than the price level without wind power fed in the system at all. In other words, peak load plants are usually preferred when production from intermittent power is low given the advantage of flexibility comparing to mid-merit plants.⁴ However, this case is reversed in the Nordic system because of the abundant hydro resource, which grants Denmark a natural tool to cope with undirected variations of wind output. Owing to this fact, price and volatility dynamics in Nord Pool needs to be examined under the influence of wind power while bearing in mind the interactions of generating technologies in adjacent countries. These specificities are reflected in our price and volatility models in order to obtain accurate market inferences and price forecasts.

Second, besides the consideration of price and volatility drivers, this work applies de-seasonalization and various GARCH processes in order to define an accurate model to predict means and volatility of electricity prices. More precisely, we explore the asymmetric impacts of price shocks and price series' heavy-tail distributional property on time-varying conditional volatility, and suggest that there is a tradeoff between considering extreme prices as a fundamental-driven phenomenon and as a stochastic behavior of the price series itself.

Third, in contrast to the studies using daily-frequency data of wholesale prices or wind output, which conceal diurnal profiles, the current chapter applies hourly data and this is especially important referring to wind power. In the Nord Pool day-ahead market, electricity is traded hourly. Therefore, using the data at the available highest frequency can help us to better understand the particularities of wind power. The nature of intermittent energy displays distinct patterns of output each hour and thus the intraday variations of output can be large, compared with power demand for example, whose intraday patterns are more predictable. To this end in order to investigate the instantaneous impact of wind power and obtain meaningful short-term predictions of the day-ahead market, one cannot overstate the importance of using data with hourly frequency, whereas seldom econometric studies have explored this facet of the story regarding to wind power generation.

wind power requires the need for sufficiently flexible technologies to deal with the fluctuation of wind power output. Bushnell (2010) argues that increasing reliance on intermittent resources causes firms to turn to more flexible and more expensive plants. Meanwhile, he also points out that the added costs associated with fluctuating end-use demand can be greatly mitigated if consumers can be more responsive to prices.

⁴Generally, base load plants include hydro, nuclear and lignite power plants; mid-merit plants are coal-fired and combined-cycle combustion gas turbines (CCGT); peak load plants consist of open-cycle gas turbines, oil or gas plants. For details on cost classification of different types of technologies, see IEA (2010).

The rest of the chapter is organized as follows. Section 3.2 summarizes the literature on price forecasts and impacts of intermittent energy on electricity spot markets. Section 3.3 introduces Nord Pool Power Exchange and wind power in Denmark, and then describes the dataset to be used. Section 3.4 provides frameworks of deseasonalization and estimation models employed in this study. Empirical results and discussions are presented in Section 3.5 and finally Section 3.6 concludes.

3.2 Literature review

The complexity of electricity price has motivated many scholars to carry out a number of studies on price forecasts. Since electricity cannot be economically stored and its demand is almost inelastic, electricity spot prices often exhibit seasonality, serial correlations, mean reverting, spikes, skewness and heavy tails (Jónsson et al., 2010). The rich econometric literature on price forecasts includes mean-reverting models (Huisman et al., 2007), regime-switching models (Huisman, 2003, 2008; Janczura and Weron, 2010; Bordignon et al., 2013), nonlinear least square models (Lucia and Schwartz, 2002) as well as time-varying parameter regression models (Karakatsani and Bunn, 2008). Furthermore given the background in which electricity spot markets have shown extensive volatility since the deregulation of electricity markets, autoregressive conditional heteroskedastic (ARCH) (Engle, 1982) or GARCH (Bollerslev, 1986) processes become commonly used to model the volatility of electricity prices (e.g. Worthington et al., 2005; Sadorsky, 2012). Despite different types of GARCH models have been exploited, there is no consensus on the most suitable GARCH specification for modeling electricity price volatility (Thomas and Mitchell, 2005; Liu and Shi, 2013). On the contrary to the differed choices of GARCH specifications, the properties of time-evolving heteroskedasticity and volatility clustering of electricity prices have been validated by several scholars (Knittel and Roberts, 2005; Garcia et al., 2005; Higgs, 2009), suggesting that a GARCH process is adequate and appropriate to model electricity price volatility in day-ahead markets. As spot prices often demonstrate heavy tails, non-Gaussian distributions were also proposed to capture this aspect (Mugele et al., 2005). However, the common goal of the price forecasting literature is to merely show that the employed models yield satisfying predictive performance for electricity spot prices without tracing the influences of specific market fundamentals such as renewable generation and cross-border trades.

On top of price forecasts, as wind power becomes increasingly competitive and raises more and more challenges to the electricity system, effort has also been made on modeling the

displacement of generating technologies brought by merit order effect and the incentives to invest in different generation technologies, ranging from gas to thermal, under the envisaged growth of RES use. For example, Forrest and MacGill (2013) show that wind penetration in the Australian electricity market is negatively correlated with the wholesale price and has greater effects at high levels of demand. This point of view is shared with Ciarreta et al. (2014) for the case of Spain, as well as with Traber and Kenfert (2011) for the case of Germany, although the main technologies to be replaced considered in these studies are different. Related to price volatility, some scholars have explored the impact on wholesale price stability caused by wind deployment and found increased price variations when electricity markets rely on a large share of intermittent generation (Green and Vasilakos, 2010; Steggals et al., 2011; Woo et al., 2011; Jacobsen and Zvingilaite, 2010; Twomey and Neuhoff, 2010). Their results are interpreted as a threat to the reliability of overall electricity supply resulting from fluctuations of wind output. Consistent with the former evidence, Ketterer (2014) illustrates very recently that the growth of wind power in Germany reduces the mean of day-ahead prices but raises the volatility in the EEX spot market. However, the study is carried out with daily average data and thus blocks out the possibility of intraday variations of spot prices and wind output, despite that accounting for these could be influential given the nature of wind feed-in. On the contrary to the results of the abovementioned studies, Jónsson et al. (2010) claim for the case of Denmark West bidding area, through a non-parametric method, diminishing intraday price variations caused by wind penetration. Regarding Denmark and the Nord Pool system, some additional work has also been dedicated to the implementation and the integration of wind power, from the perspectives of macroeconomics (Sperling et al., 2010), geographical aggregation (Østergaard, 2008) and end-user demand responsiveness (Grohnheit et al., 2011). Munksgaard and Morthorst (2008) recognized that facing higher volatility risk-averse investors would be reluctant to invest in wind power in Denmark after a high feed-in tariff scheme was replaced by a new tariff scheme aiming at a smooth transition from a guaranteed price to a market price for wind producers. However, none of these studies has explicitly quantified the impacts of large wind penetration on the day-ahead market or examined the variations of market signals facing wind intermittency.

The lack of evidence on the short-run links between wind power and wholesale electricity markets calls for a reexamination of their relationships with intraday data. The present work differs from all previous studies and fills the gap on seeking this link between day-ahead market performance and wind generation by reflecting on the specific market design of Nord Pool and its particularities on generation mix where cross-border transmissions and strategic hydro

storage are essential for system stabilization. Additionally as mentioned in Section 3.1, most up-to-date econometric work that involves electricity price forecasts or impacts of intermittent technologies has used the average of daily wholesale prices or daily-frequency data. By doing so, such specifications tend to conceal intraday patterns of spot prices and especially the ones of wind output. Therefore, this work contributes to literature by predicting electricity prices and volatility with high-frequency data in relation with wind deployment and also examining other influential factors in the determination of their relationships.

3.3 Market settings and fundamentals

In this section, we describe the market settings of the Nord Pool Spot electricity market and the development of wind power in Denmark, which inspire us on choosing the most representative market fundamentals to analyze the short-run dynamics of the Nord Pool day-ahead market. Besides fluctuations in wind power output, we show that net coupling inflows to Nord Pool from other markets and net power exchange flows to Denmark from other Scandinavian countries are the two fundamental drivers of the Nordic day-ahead market. In the end, the dataset used for this study is introduced and various properties of the price series and wind output are analyzed.

3.3.1 The Nord Pool Spot and system price

Nord Pool Spot operates the Elspot day-ahead market, along with the Elbas intraday market and N2EX financial market⁵ in the Nordic (Denmark, Finland, Norway and Sweden) and Baltic (Estonia, Latvia and Lithuania) regions.⁶ At Elspot, the hourly system price is calculated on the basis of equalizing aggregate supply and demand represented by bids and offers for the entire trading region. Gate closes at 12:00 CET, which is the deadline for submitting bids for power that will be delivered in the following day for the period of midnight to midnight. Because of transmission constraints, the Nordic market is divided into various bidding areas with mostly area prices being different from system prices to reflect transmission scarcities. Therefore, the system price denotes an unconstrained market-clearing price since the trading capacities between the bidding areas have not been taken into account in finding this price.

⁵N2EX was formerly based in the UK and is wholly owned by Nord Pool Spot since October 2014. For more details on Elbas and N2EX.

⁶The Elspot bidding areas are opened in Estonia in 2010 and in Latvia in 2013. Elbas is introduced in both Latvia and Lithuania in 2013.

Although the system price does not depend on the internal transmission scarcity of Nord Pool, it is certainly influenced by external market coupling flows from other European spot markets, i.e. Germany and the Netherlands.⁷ Therefore, the analyses carried out in the present chapter are based on the Nord Pool system price accounting for net market coupling flows between Nord Pool and other spot markets in order to examine the overall impacts of wind power on the wholesale system.

3.3.2 Wind power in Denmark

By the end of 2013, Denmark had achieved 4792MW of wind power capacity with an annual average rate of 33.2% of wind power in final consumption, by far the largest share of any country in the world. The rest of the electricity generation almost all comes from Combined Heat and Power (CHP) plants. By 2003, all wind generators were connected to the grid. The remuneration was made up of the market price plus a premium. After the booming of wind generation installations in the 1990s, the wind power development stagnated once the feed-in-tariff was abandoned in 2004. According to the data from the Global Wind Energy Council (GWEC, 2014) between 2004 and 2008 the Danish wind capacity was only added by 129MW. In 2009, there was a significant increase in new installations of wind power capacity as a combined result from the development of offshore wind power and reinforced supports for new wind turbines (DEA, 2010).⁸ In 2011, the Danish government set an ambitious target of 50% wind energy in electricity consumption by 2020 as part of its long-term strategy to achieve 100% independence from fossil fuels in the national energy mix by 2050 (DEA, 2014). Fig. 3.1 demonstrates the annual development of the national production, gross consumption as well as the shares of wind power in Denmark between 2009 and 2013. The proportions of wind generation in gross consumption and total production have been steadily growing since 2009. While the annual gross consumption stays relatively stable, the total power production in Denmark varies each year. As the rationale will be explained later in section 3.3, for example, a lower total production in 2012 corresponds to a rather wet year with respect to other years in Scandinavia, which allows Denmark to import more electricity produced by hydropower from Sweden and Norway in order to lower its domestic production from fossil fuels.

⁷The Netherlands is connected to Norway.

⁸According to the Danish Promotion of Renewable Energy Act that came into force in 2009, electricity produced by onshore wind turbines that connected to the grid on or after 21 February 2008 is paid a supplement of DKK 0.25 per kWh additional to market prices. As for the supplement paid to electricity produced by offshore wind power, a process of government tender determines the amount.

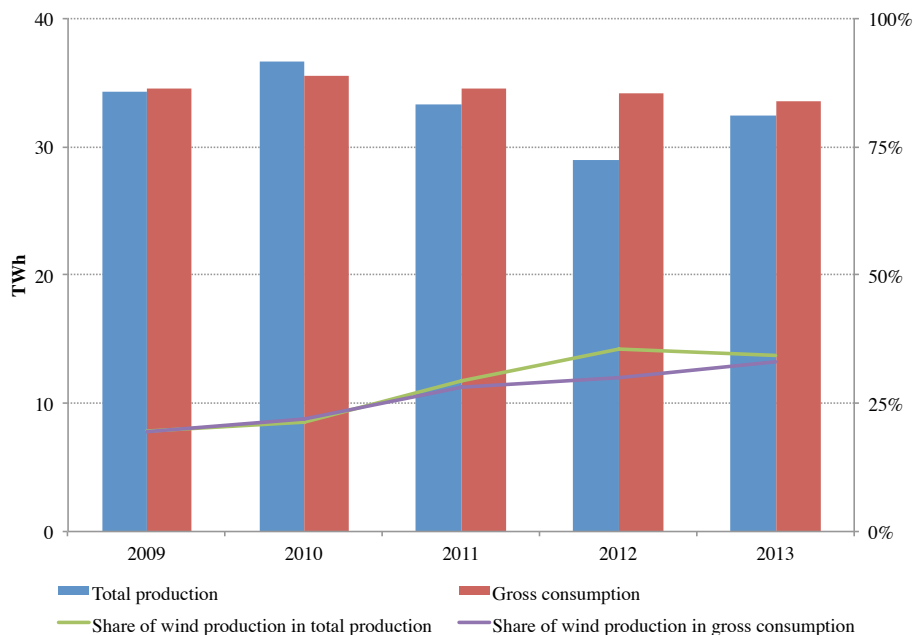


Figure 3.1 – Evolutions of total production, gross consumption and wind power generation in Denmark. Data source: Author’s calculation based on energinet.dk (2015).

3.3.3 Substitution between wind power and hydropower

In Elspot, Denmark is divided into two bidding areas: Denmark West (DK1) and Denmark East (DK2). The two areas have extensive connections with neighboring countries but had little exchange between them until 2010 (Østergaard, 2008). Fig. 3.2 illustrates the international connections and transmission capacities between Denmark and other neighboring countries. By 2014, both DK1 and DK2 have built up a prominent level of transmission capacities to the north with the Scandinavian countries as to the south with Germany. The only connection between western and eastern Denmark is the Great Belt Power Link, commissioned in 2010 with a transmission capacity of 600MW. The inauguration of the Great Belt Link also signified the end of era of complete separation between the two Danish bidding regions.

As seen in Fig. 3.2, Denmark is well connected to its neighboring countries—Germany, Norway and Sweden—and the latter two have a high proportion of hydro generation.⁹ The Danish strategy to handle the varying wind output is to coordinate with available hydropower in Norway and Sweden through its imports and exports (Green, 2012). By exchanging power

⁹Hydropower represents virtually all of installed capacity (95%) in Norway and nearly half of the Swedish generation capacity (Nordic Energy Regulator, 2014).

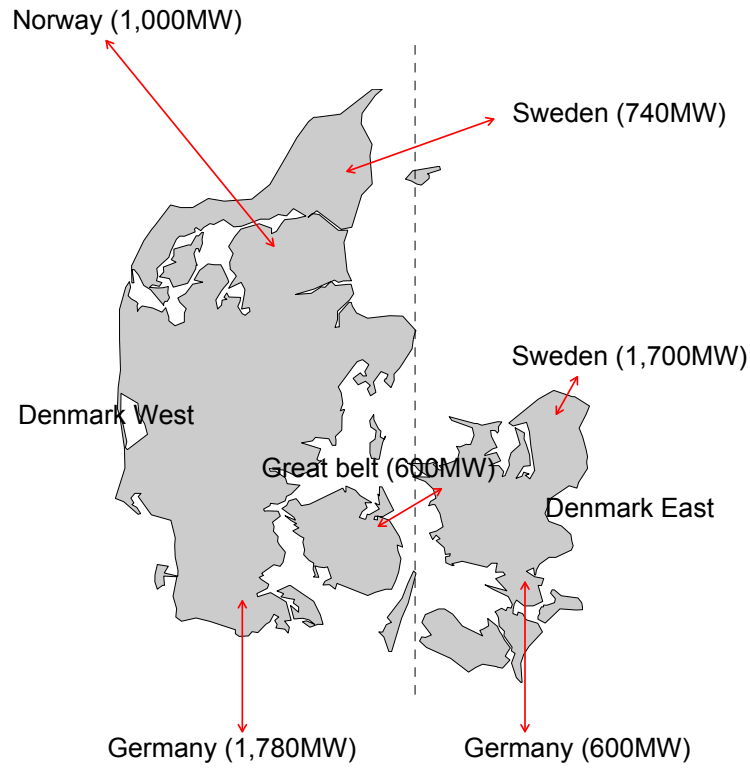


Figure 3.2 – Cross-border connections and transmission capacities between Denmark and neighboring countries. Data source: Author’s realization based on energinet.dk (2015).

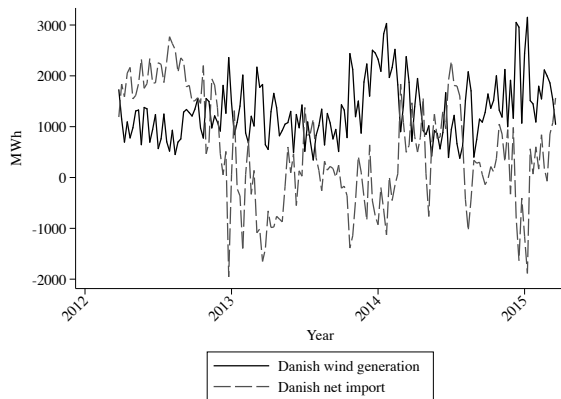
produced by wind farms with hydro, the opportunity cost foregone is the expected cost of hydro generation, while the quantity of water stored in hydro reservoir changes from a rainy season to a dry season on a yearly basis. Therefore, stable hydro storage in Norway and Sweden has a buffering effect on the uncontrollable output of wind power in Denmark. When the Danish wind generation is high, Denmark can export surpluses to neighboring countries and make savings on the value of hydropower. The interest on exporting wind output is especially greater if hydro storage is low. In the opposite case, however, a lack of wind power calls in an increase in imports or domestic thermal generation. In this case, import is particularly favorable to Denmark when the storage of water reservoir in Norway and Sweden is high, making import less costly compared with the cost of launching domestic CHP plants. In fact according to Green and Vasilakos (2012), Denmark adjusts variations in its net exports exactly in this way. Fig. 3.3 presents the relationships among net power imports, wind generation in Denmark and (fitted) storage of hydro reservoir in Norway and Sweden.¹⁰ Fig. 3.3 (left) clearly demonstrates a negative correlation between the Danish wind generation and its net imports, which indicates that Denmark exports its surplus of wind production to its neighboring countries. The figure on the right shows that the net quantity of electricity imported in Denmark and the level of hydro storage in Norway and Sweden are positively correlated. That is to say, Denmark tends to import electricity when its wind production is low and foreign hydro storages are high. As a consequence, the market-specific substitution of generating technologies in the Nordic electricity market can be justified and captured by the variable of net electricity imports in Denmark.

Accordingly, having demonstrated the importance of the market exchange flows between the Nordic market and other countries in Section 3.3.1 as well as the substitution of hydropower to wind power in Denmark’s strategy to handle wind intermittency through net imports, we expect that these two factors would have significant impacts on the determination of the price level and volatility in the day-ahead market. These considerations along with wind penetration are brought forward in our model specifications.

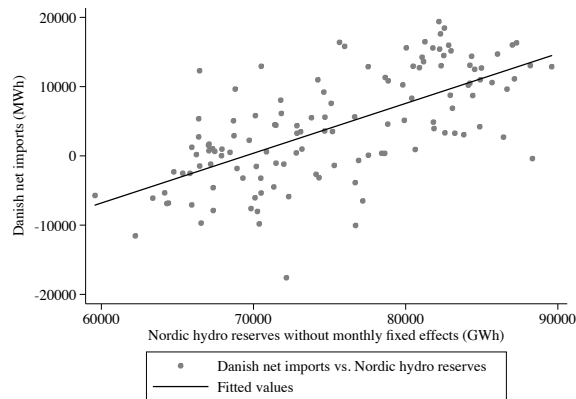
3.3.4 The data

The time series data of system prices in each trading hour measured in euro per megawatt hour (€/MWh) in the Nord Pool Spot are retrieved from the Danish Transmission System Operator Energinet.dk (2015). Since we focus on Elspot, at the point of one day prior to the

¹⁰As the hydro reservoir displays strong seasonal and annual pattern, a fitted curve is obtained by removing monthly fixed effects.



Hourly averages of Danish wind generation and net imports per week



Hourly averages of Danish net imports and Nordic hydro storage per week

Figure 3.3 – Correlations between Danish wind generation, Danish net imports and Nordic hydro storage. Data source: Author’s realization based on energinet.dk and Nord Pool Spot (2015).

physical delivery of electricity, the available and appropriate information to be used would be the forecasts on wind production in Denmark and total demand in all Nord Pool areas. These two forecasts are obtained from the website of Nord Pool Spot (2015). Furthermore, also sourced from Nord Pool Spot, the data on market coupling flows and Danish net power imports are calculated by aggregating the net flows of various bidding areas or neighboring countries.¹¹ All quantity variables are measured in megawatt hour (MWh). Finally, the dataset covers the period from March 25, 2012 to March 24, 2015, including 26,280 observations with hourly frequency. Each day has a length of 24 hours. Table 3.1 provides a summary of statistics of the system price series, according to which positive skewness and excess kurtosis of the spot prices can be detected. Furthermore, it is worth noting that negative system prices have not been present in our dataset.¹² One of the idiosyncrasies of wholesale electricity prices is seasonality, which presents hourly, daily, weekly and monthly. As shown in Figs. A.1 and A.2 in Appendix A, electricity prices exhibit distinguished multiple levels of seasonality depending on hours of day, days of week and months of year. As will be discussed in Section 3.4, price

¹¹The original data are obtained for each bidding area in the Nordic market.

¹²In contrast to system prices, we do observe negative area prices due to high penetration of renewable generation, low demand and transmission congestion. For example, they are detected for 143 hours in Denmark West and 98 hours in Denmark East during the same period, among which a lot of them happen around the time of the Christmas and the New Year.

variations as a result of seasonality are not caused by market conditions or by intermittent generation and thus should be treated before applying econometric techniques.

Table 3.1 – Summary of statistics of the system price series (€/MWh)

| Mean | Median | S.D. | Max. | Min. | Skew. | Kurt. |
|-------|--------|------|--------|------|-------|-------|
| 32.64 | 32.17 | 9.94 | 224.97 | 1.38 | 3.47 | 48.51 |

S. D., Max., Min., Skew. and Kurt. are standard deviation, maximal value, minimal value, skewness and kurtosis of the electricity price series for the period of March 25, 2012 to March 24, 2015.

Unlike the day-ahead electricity price, wind generation does not exert a specific hourly regularity although the output level can be largely and continuously volatile. The peculiarity of intermittent technology results in stable means and substantial variances in wind output. This characteristic is demonstrated by Fig. B.1 in Appendix B, in which the average hourly wind production only slightly peaks in the afternoon hours during spring and summer seasons while it stays relatively flat during autumn and winter. While the average hourly wind generation varies from 750MWh to 1700MWh over the year, the standard deviations of the hourly wind production are almost unvarying and as large as around 1000MWh for all four seasons. Hence in contrast to the studies that treat the price series in each hour separately (e.g. Bordignon et al., 2013) or as panel data (e.g. Huisman et al., 2007), we treat our time series data continuously on the account of the continuity and short-term variations of wind generation.

3.4 Methodology

3.4.1 Long-term and short-term seasonal components

The electricity price series under study is high frequency and characterized by monthly, day-of-week and hourly seasonality. Carefully treating long- and short-term seasonality can produce superior estimation and prediction results (Janczura et al., 2013). Given that intermittent wind output is substantially influential on intraday price patterns, we need to keep the hourly price patterns as well as abrupt variations to the largest extent while removing monthly and weekly seasonality. There are different treatments in econometric literature for dealing with seasonal components in electricity price dynamics.¹³ Following Weron (2009) and Janczura

¹³Other suggestions in the literature of energy economics are for instance, adding seasonal dummies, sinusoidal functions and exponentially weighted moving average. For more details, see Trück et al. (2007) and Janczura et al. (2013).

and Weron (2010)'s suggestion of a three-step deseasonalization approach, we represent the spot price P_t by a sum of two independent parts: a seasonal part f_t describing the predictable behavior of electricity prices and a residual stochastic part p_t , i.e. $P_t = f_t + p_t$.¹⁴ Additionally, the deterministic part f_t is further decomposed into a long-term seasonal component (LTSC) L_t and a weekly short-term seasonal component (STSC) S_t . Then for the price series in each hour, the first step consists of applying wavelet decomposition and smoothing techniques to estimate L_t . Wavelet decomposition is more robust to price spikes and jumps and less strictly periodic alternative to Fourier analysis (Janczura et al., 2013; Stevenson et al., 2006). Here a continuous function (i.e. electricity price series) can be approximated by a set of orthogonal signal components that include one father wavelet function and a sequence of mother wavelet functions:

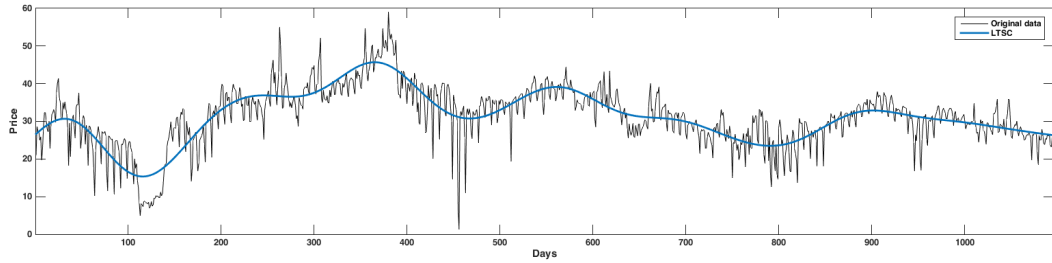
$$\begin{aligned}
 f(t) = & \sum_{k=-\infty}^{\infty} \alpha_{J,k} \Phi_{J,k}(t) + \sum_{k=-\infty}^{\infty} \beta_{J,k} \psi_{J,k}(t) + \sum_{k=-\infty}^{\infty} \beta_{J-1,k} \psi_{J-1,k}(t) + \\
 & \cdots + \sum_{k=-\infty}^{\infty} \beta_{j,k} \psi_{j,k}(t) + \cdots + \sum_{k=-\infty}^{\infty} \beta_{1,k} \psi_{1,k}(t)
 \end{aligned} \tag{3.1}$$

where J is a positive integer representing the coarsest level of resolution, k is the translation parameter associated with a shift in the time t , $\alpha_{j,k}$ and $\beta_{j,k}$ are the wavelet transform coefficients, $\Phi_{J,k}(t)$ and $\psi_{j,k}(t)$ are the mother and father wavelet functions, respectively.

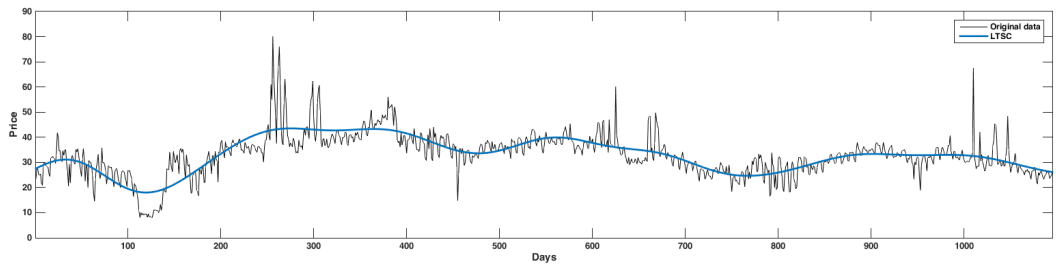
Therefore, by properly choosing the maximum scale sustainable by the number of observations 2^J , the father wavelet can serve as estimation for a long-term trend of the signal, while adding a mother wavelet at each step can improve the estimation of the original signal until the complete reconstruction of the original signal. As in Janczura et al. (2013), we choose the parameter $J = 6$, which approximately corresponds to bimonthly ($2^6 = 64$) smoothing. Therefore, we obtain the price series without the LTSC by removing the wavelet filters from P_t . Taking the seventh and 16th hour of a day for an illustration, the results of the LTSC estimation are shown in Fig. 3.4.

Second, the price series without the SRSC is obtained by removing a weekly periodic pattern to account for the day-of-week fixed effects (Janczura and Weron, 2010; Weron, 2006). To avoid the influence of short-lived price spikes and jumps, we subtract weekly medians

¹⁴For a robustness check, a linear deseasonalization process with seasonal dummies in combined with an ARMA-GARCH model leads to roughly similar estimation results but worse performance in model fits. See Appendix C.



6am-7am



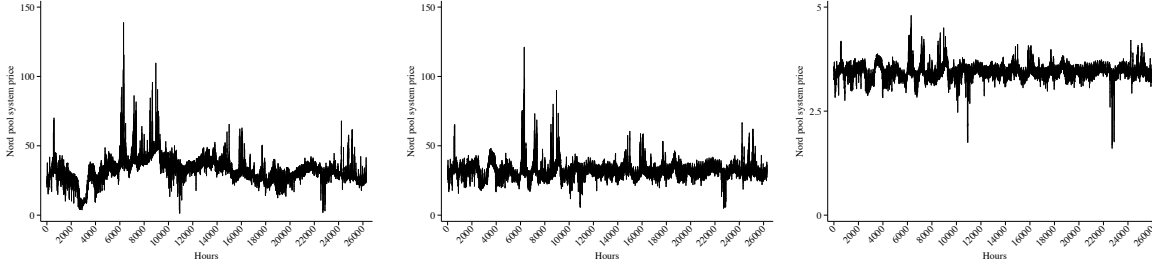
3pm-4pm

Figure 3.4 – Estimation of the long-term seasonal components (LTSC) of the day-ahead prices

instead of weekly means from the obtained price series above. Finally for each hour, the deseasonalized prices $p_t = P_t - L_t - S_t$ are scaled up with their hourly means, so that log-prices can be used for this analysis. The patterns of hourly prices in Elspot are shown in Fig. 3.5, reflecting that the removal of seasonality is effective. The deseasonalized hourly spot prices and their logarithmic forms are relatively smoother.

As a pre-examination of the suitability of a GARCH model, we conduct Ljung-box test (Ljung and Box, 1978) and Engle (1982)'s Lagrange multiplier test (ARCH-LM) for the residuals of deseasonalized prices. The results reported in Table 3.2 strongly reject their null hypotheses, indicating that price residuals display temporal autocorrelations and the error terms exhibit time-varying volatility clustering. In order to model the volatility of the day-ahead prices, a GARCH process is in consequence needed.¹⁵

¹⁵Augmented Dickey-Fuller (ADF) (Dickey and Fuller, 1979) and Phillips and Perron (PP) (1988) tests are carried out for all variables used in this study, indicating that all series are stationary. Therefore a GARCH process can be applied without the concern of spurious regression.



Original price

Deseasonalized price

Log-deseasonalized price

Figure 3.5 – Hourly day-ahead spot price and deseasonalized price in Elspot from March 25, 2012 to March 24, 2015 (€/MWh). Data source: Author’s realization based on energinet.dk (2015).

Table 3.2 – Results of Ljung-Box and ARCH-LM tests

| | LB test | ARCH test |
|-------|------------------|-----------------|
| Price | 3.376e+05 (0.00) | 21200.15 (0.00) |

p -values between parentheses. Ljung-Box statistics correspond to a test of the null of no autocorrelation with the number of lags equal to 40. ARCH Lagrange multiplier statistics correspond to a test of the null of no ARCH effect.

Finally, we plot partial autocorrelation functions (PACF) of the day-ahead prices in Fig. 3.6 in order to grab the gist of appropriate autoregressive orders. PACF shows great intraday temporal correlations, which shrink to a relatively insignificant level after 25 hours. Therefore, autoregressive terms are included in order to capture intraday partial autocorrelations.

3.4.2 Model specifications

In order to model price and volatility dynamics under the influence of wind power, net market coupling and power import, we need to specify a mean and a volatility equation respectively. For the mean equation, denoting by y_t the deseasonalized electricity price in logarithmic form at time t , the proposed AR(P) model fits the equation of the price level as follows:

$$y_t = \delta + X_t' \theta + \sum_{i=1}^P \rho_i y_{t-i} + \varepsilon_t \quad (3.2)$$

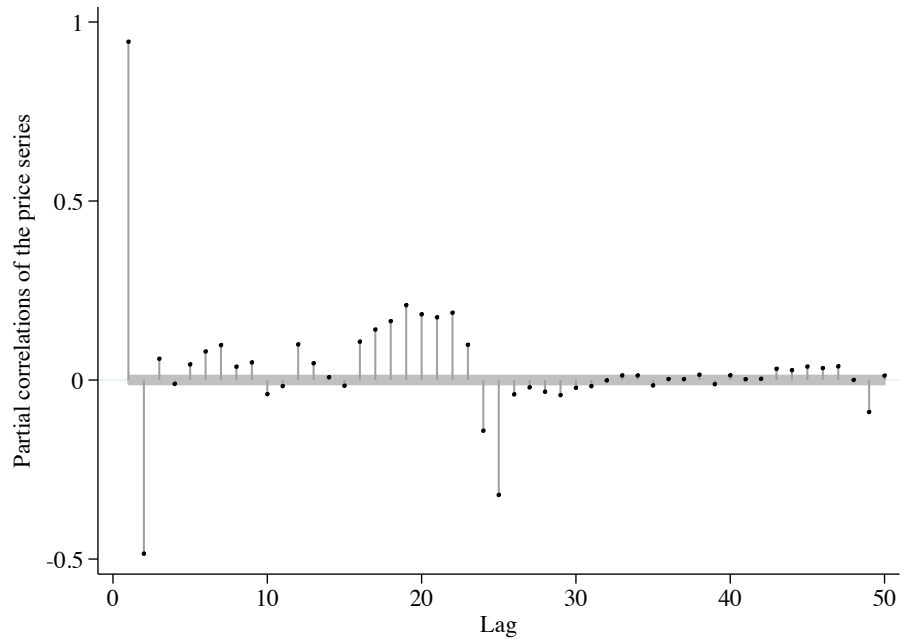


Figure 3.6 – Partial autocorrelation function (PACF) of the Nord Pool system prices. Data source: Author’s calculation based on energinet.dk (2014).

where δ is the constant, θ is the coefficient vector associated with exogenous variables, ρ_i is the autoregressive coefficient of the price series, P is the lag parameters of the dependent variable, ε_t is the error term which follows Gaussian distribution conditional on past history, X'_t is a set of exogenous variables, as indicated in the previous section, that may be expressed as $X'_t = (Wind_t, Coupling_t, Import_t, Load_t)$, where $Wind_t$ stands for the hourly prognosis of wind generation; $Coupling_t$ represents the net coupling flows into Elspot from other European spot markets; $Import_t$ represents the net import flows into Denmark from Norway and Sweden; $Load_t$ is the demand prognosis for the Nord Pool day-ahead market included as a control variable. Among the above four explanatory variables, $Wind_t$ and $Load_t$ are in logarithmic form.¹⁶

In an integrated framework, the conditional price variance defined by a GARCH(1, 1) process with exogenous variables added in the specification is as follows:

$$\sigma_t^2 = \omega + \alpha\varepsilon_{t-1}^2 + \beta\sigma_{t-1}^2 + Z'_t\pi \quad (3.3)$$

where ω is a constant term, α and β are the coefficients of the ARCH term ε_{t-1}^2 and GARCH term σ_{t-1}^2 respectively, Z'_t is a set of exogenous variables included in the variance equation and π is the associated coefficient vector. A fact that should be borne in mind is that the non-negative constraint on σ_t^2 should be checked jointly with the values of all regressors. It is also important to notice that a conventional GARCH specification as Eq. (3.3) implies that the impacts of ε_{t-1}^2 is symmetric, meaning that positive and negative shocks to spot prices influence the volatility to the same extent. For the above two reasons, we further explore an exponential GARCH (EGARCH) developed by Nelson (1991) in order to relieve the non-negativity constraint on conditional variances and capture the asymmetric impacts of innovation terms on volatility. In an EGARCH(1,1) framework, the specification for the conditional variance is:

$$\log(\sigma_t^2) = \omega + \alpha\left(\left|\frac{\varepsilon_{t-1}}{\sigma_{t-1}}\right| - E\left|\frac{\varepsilon_{t-1}}{\sigma_{t-1}}\right|\right) + \gamma\frac{\varepsilon_{t-1}}{\sigma_{t-1}} + \beta\log(\sigma_{t-1}^2) + Z'_t\pi \quad (3.4)$$

Therefore for $\gamma > 0$, positive shocks will produce a bigger impact on price volatility than negative shocks and vice versa. By taking the logarithm of the conditional variance, the

¹⁶Since net coupling flows and net import flows contain both positive and negative values, they are not in logarithmic form. For a robustness check, scaling up the minimal values of these two variables to zero and then taking the log do not alter the main results, but for the sake of price and volatility interpretation and prediction, we prefer to use the original values of the variables.

EGARCH model ensures the process to be positive by construction and this is especially meaningful given the inclusion of explanatory variables.

Finally to further capture the heavy-tail property of electricity prices, a Student's t distribution replacing the Gaussian error distribution is used to fit the above two GARCH models. The mean and variance equations are estimated by maximum likelihood, and the orders of autoregressive terms are chosen in consistency with the orders indicated in the partial autocorrelation functions.

3.4.3 Model evaluation and forecast accuracy

In order to evaluate the performance of the different GARCH models, we provide Akaike's Information Criterion (AIC) and Schwarz's Bayesian Information Criterion (BIC) to compare the in sample goodness-of-fit. For the performance of out-of-sample forecasts, root-mean squared error (RMSE), mean absolute error (MAE), mean absolute percentage error (MAPE), and Theil's inequality coefficient (TIC) are generally used as forecast error statistics. They are computed as follows:

$$RMSE = \sqrt{\frac{1}{h} \sum_{t=T+1}^{T+h} (\hat{y}_t - y_t)^2} \quad (3.5)$$

$$MAE = \frac{1}{h} \sum_{t=T+1}^{T+h} |\hat{y}_t - y_t| \quad (3.6)$$

$$MAPE = \frac{100}{h} \sum_{t=T+1}^{T+h} \left| \frac{\hat{y}_t - y_t}{y_t} \right| \quad (3.7)$$

$$TIC = \frac{\sqrt{\frac{1}{h} \sum_{t=T+1}^{T+h} (\hat{y}_t - y_t)^2}}{\sqrt{\frac{1}{h} \sum_{t=T+1}^{T+h} \hat{y}_t^2 + \frac{1}{h} \sum_{t=T+1}^{T+h} y_t^2}} \quad (3.8)$$

where \hat{y}_t and y_t are the predicted value and true observed value respectively, and h is the forecast horizon. Smaller forecast error statistics are usually preferred while choosing the best model, and among them RMSE and MAE depend on the scale of the variable while MAPE and TIC do not.

3.5 Empirical results and analyses

3.5.1 Estimation results of a conventional GARCH model

The estimated results of the above-mentioned AR-GARCH process based on Eqs. (3.2) and (3.3) are summarized in Table 3.3. The first column presents the results of the specification only controlling for demand. Columns (2)–(4) present the estimation results by adding wind power generation, net coupling flows between Nord Pool and external markets as well as the Danish net imports from Norway and Sweden in the mean equation, while columns (5)–(7) report the estimation results by adding the same exogenous variables in the variance equation. At the first glance, almost all coefficients are highly significant. Adding net coupling and net import flows does not alter the significance levels either the signs of the coefficients of wind and consumption forecasts, suggesting the robustness of the model and the importance of cross-border electricity exchanges in determining the day-ahead prices and volatility. The gradually lowered values of AIC and BIC signify improvements on model fits from more thorough consideration of market fundamentals in price and volatility dynamics. As shown in Table 3.3 in the mean equation across all specifications, all estimates for wind power and net coupling flows with other wholesale markets are negative, whereas the estimates for the Danish net electricity imports are positive. Consistent with our expectation from the merit order effect, an increase in wind output leads to a decrease in electricity price in the Nordic market as RES crowds out conventional plants with higher marginal costs out of generating profile. In the case of Nord Pool, more expensive thermal plants are substituted by wind power to produce electricity when wind penetration is high, bringing down the average electricity spot price. In the variance equation, the negative impact of wind power on the conditional variance may seem surprising in the first place, but this has to be analyzed jointly with internal and external electricity exchange flows. This point will be discussed later on in section 3.5.3.

3.5.2 Asymmetric GARCH and heavy-tail error distribution

We now incorporate the asymmetric impacts of innovations on conditional variances based on the aforementioned EGARCH process. Since electricity day-ahead prices often show more extreme values, the assumption on a Gaussian error distribution may not be appropriate. For this reason, we further fit the errors with a Student's t distribution in order to accommodate

Table 3.3 – Estimation results for the price and variance equations with market fundamentals

| | AR specifications | | | | GARCH specifications | | |
|--------------------------|-------------------|-----------|--------------|--------------|----------------------|--------------|--------------|
| Mean equation | (1) | (2) | (3) | (4) | (5) | (6) | (7) |
| δ | -0.423*** | 0.042 | 0.884*** | 0.970*** | -1.139*** | -1.146*** | 3.116*** |
| Wind | | -0.015*** | -0.013*** | -0.010*** | -0.002*** | -0.002*** | -0.010*** |
| Coupling | | | -1.19e-05*** | -8.80e-06*** | -8.13e-06*** | -8.05e-06*** | -7.69e-06*** |
| Import | | | | 4.44e-06*** | 2.28e-06*** | 2.39e-06*** | 2.63e-06*** |
| Load | 0.362*** | 0.328*** | 0.248*** | 0.238*** | 0.426*** | 0.427*** | 0.036*** |
| AR(1) | 1.206*** | 1.190*** | 1.195*** | 1.194*** | 1.261*** | 1.260*** | 1.206*** |
| AR(2) | -0.419*** | -0.411*** | -0.419*** | -0.418*** | -0.488*** | -0.487*** | -0.480*** |
| AR(3) | 0.059*** | 0.054*** | 0.059*** | 0.059*** | 0.089*** | 0.088*** | 0.072*** |
| AR(6) | -0.051*** | -0.053*** | -0.060*** | -0.060*** | -0.001 | -0.000 | -0.039*** |
| AR(7) | 0.072*** | 0.072*** | 0.080*** | 0.080*** | 0.066*** | 0.066*** | 0.087*** |
| AR(8) | -0.044*** | -0.046*** | -0.050*** | -0.050*** | -0.087*** | -0.085*** | -0.120*** |
| AR(9) | 0.050*** | 0.050*** | 0.048*** | 0.048*** | 0.105*** | 0.103*** | 0.104*** |
| AR(12) | -0.038*** | -0.037*** | -0.044*** | -0.043*** | -0.064*** | -0.064*** | -0.067*** |
| AR(14) | 0.053*** | 0.053*** | 0.059*** | 0.059*** | 0.034*** | 0.035*** | 0.047*** |
| AR(16) | -0.048*** | -0.047*** | -0.048*** | -0.048*** | 0.012*** | 0.012*** | -0.027*** |
| AR(19) | 0.018*** | 0.021*** | 0.023*** | 0.023*** | -0.029*** | -0.029*** | 0.008*** |
| AR(23) | 0.255*** | 0.256*** | 0.261*** | 0.260*** | 0.099*** | 0.096*** | 0.120*** |
| AR(24) | -0.127*** | -0.115*** | -0.118*** | -0.117*** | -0.010*** | -0.006*** | -0.011*** |
| Variance equation | | | | | | | |
| ω | | | | | -0.001*** | -0.001*** | -0.000 |
| α | | | | | 0.850*** | 0.855*** | 0.696*** |
| β | | | | | 0.219*** | 0.217*** | 0.302*** |
| Wind | | | | | -2.98e-05*** | -2.43e-05*** | -6.37e-05*** |
| Coupling | | | | | | -1.91e-08*** | -5.76e-08*** |
| Import | | | | | | | -5.14e-08*** |
| Load | | | | | 1.59e-04*** | 1.18e-04*** | 7.57e-05*** |
| R2 | 0.94 | 0.94 | 0.94 | 0.94 | 0.93 | 0.93 | 0.94 |
| Adj. R2 | 0.94 | 0.94 | 0.94 | 0.94 | 0.93 | 0.93 | 0.94 |
| LL | 46890 | 46987 | 47276 | 47284 | 53737 | 53753 | 54330 |
| AIC | -3.57 | -3.58 | -3.60 | -3.60 | -4.09 | -4.09 | -4.14 |
| BIC | -3.57 | -3.57 | -3.59 | -3.59 | -4.08 | -4.09 | -4.13 |

Wind is the log hourly wind generation forecasts for Denmark. Coupling is the net flow of electricity from Germany and the Netherlands to Nord Pool Spot. Import is the net flow of electricity from Norway and Sweden to Denmark. Load is the log consumption forecasts in Nord Pool. Asterisks indicate significance at *** $p < 0.01$, ** $p < 0.05$, * $p < 0.1$. LL, AIC and BIC are log likelihood, Akaike Information and Bayesian Information Criteria respectively.

fatter tails of the spot prices.¹⁷ The estimation results of the asymmetric GARCH with Gaussian or Student’s t distributions are described in Table 3.4.¹⁸ While the estimates of coefficients of the mean equations remain stable in asymmetric GARCH models compared with the conventional GARCH, the estimates of the variance equations vary in scales and this is due to different function forms in GARCH and EGARCH. Under Gaussian assumption according to the AIC and BIC criterion, there is a slight gain in model fits when moving from GARCH to EGARCH. The parameter γ measuring asymmetric effects is significant and positive in the EGARCH models. As a consequence, the asymmetric influences of innovations on conditional variances found here is a “standard leverage effect”. Knittel and Robert (2005) and Liu and Shi (2012) have defined an inverse leverage effect as one of the particularities of electricity spot prices, which means that positive shocks to electricity prices would influence price volatility to a greater extent compared with negative shocks. This is the inverse case to the leverage effect in financial markets in which bad news often has a larger influence on volatility. However, contrary to their findings, here the significant positive sign of the parameter γ contests the finding of inverse leverage effect by evincing resulted larger volatility from negative price shocks in the case of the Elspot electricity market. That is, after controlling for the market fundamentals, this price series’ particularity is not valid anymore. Consequently, the reliability of the asymmetric impacts of innovations may largely depend on the accountability of market fundamentals as well as the stochastic properties of price series in a specific market.

Considering the Student’s t error distribution, the estimate of the t distribution parameter $v > 2$, is highly significant in both GARCH and EGARCH specifications, effectively controlling for errors’ fat tails. It is also clear that Student’s t distributional errors fit the electricity prices much more accurately according to the significantly improved AIC and BIC compared with the results in the second and the third columns. Especially, the ARCH tests for GARCH and EGARCH with t distribution suggest that the null hypothesis of no ARCH effects is not rejected, meaning that serial correlations are sufficiently captured by these models. Finally, it is noticeable that under t distribution the coefficients of wind power generation lose significance to some extent in the variance equation. This is understandable in the sense that extreme prices can be seen as a result of wind fluctuations or a stochastic behavior of price series itself. Accordingly, a choice needs to be made in order to precisely predict spot prices between modeling price variations as fundamental-driven and incorporating large fluctuations

¹⁷The estimation and forecast results with a generalized error distribution (GED), which can also capture heavy tails, are reported in Appendix D, showing similar estimation and forecast performance as the one of a Student’s t distribution.

¹⁸To conserve space, only AR order 1 is reported in Table 3.4.

Table 3.4 – Estimation results of asymmetric GARCH compared with conventional GARCH

| Mean Equation | Gaussian | | Student's t | |
|--------------------------|--------------|--------------|---------------|--------------|
| | GARCH | EGARCH | GARCH | EGARCH |
| δ | 3.116*** | 3.575*** | 1.208*** | 1.159*** |
| Wind | -0.010*** | -0.010*** | -0.008*** | -0.008*** |
| Coupling | -7.69e-06*** | -7.07e-06*** | -9.95e-06*** | -9.76e-06*** |
| Import | 2.63e-06*** | 3.44e-06*** | 3.45e-06*** | 3.66e-06*** |
| Load | 0.036*** | 0.009 | 0.203*** | 0.207*** |
| AR(1) | 1.206*** | 1.254*** | 1.295*** | 1.295*** |
| Variance Equation | | | | |
| ω | -0.000 | -0.776*** | 0.003*** | -0.248 |
| α | 0.696*** | 0.415*** | 1.056*** | 0.903*** |
| β | 0.302*** | 0.930*** | 0.182*** | 0.613*** |
| γ | | -0.042*** | | -0.024* |
| v | | | 2.692*** | 2.667*** |
| Wind | -6.37e-05*** | -0.046*** | -2.65e-06 | -0.021** |
| Coupling | -5.76e-08*** | -4.56e-05*** | -2.87e-08*** | -4.04e-05*** |
| Import | -5.14e-08*** | -4.96e-05*** | -3.88e-08** | -5.85e-05*** |
| Load | 7.57e-05*** | 0.028*** | -2.41e-04*** | -0.256*** |
| R2 | 0.94 | 0.94 | 0.94 | 0.94 |
| Adj. R2 | 0.94 | 0.94 | 0.94 | 0.94 |
| LL | 54330 | 54484 | 59085 | 58979 |
| AIC | -4.14 | -4.15 | -4.50 | -4.49 |
| BIC | -4.13 | -4.14 | -4.49 | -4.48 |
| DW stat. | 1.97 | 2.15 | 2.24 | 2.24 |
| ARCH test | 0.16 | 0.00 | 0.91 | 0.96 |

γ is the estimated asymmetric parameter in EGARCH model. v is the t distribution parameter. Wind is the log hourly wind generation forecasts for Denmark. Coupling is the net flow of electricity from Germany and the Netherlands to Nord Pool Spot. Import is the net flow of electricity from Norway and Sweden to Denmark. Load is the log consumption forecasts in Nord Pool. Asterisks indicate significance at *** $p < 0.01$, ** $p < 0.05$, * $p < 0.1$. LL, AIC and BIC are log likelihood, Akaike Information and Bayesian Information Criteria respectively. ARCH test reports the P-value by testing the null hypothesis of no ARCH effects.

into a heavy-tail distribution. Finally, analogous rationale could be applied to explain the alleviated effect from the demand side when price spike and jumps are captured by a heavy-tail distribution rather than load fluctuations.

3.5.3 Discussions of estimation results

To further interpret our results, we concentrate on the EGARCH specification in Table 3.4 given the advantages that EGARCH satisfies the non-negativity constraint on the conditional variance by construction and a log-form specification of the conditional variance provides a convenient way to interpret variance elasticity. In the mean equation, the model specification includes the Danish wind forecasts and the Nordic consumption forecasts in logarithmic forms. As a consequence, the values of coefficients of the wind generation and the Nordic consumption forecasts could be interpreted as elasticities of price and demand. That is to say, an increase of 1% in wind generation would lead to, on average, a decrease of 0.008% in the Nord Pool day-ahead price. More concretely, a 10% increase of intermittent wind generation only reduces the average day-ahead price by approximately 0.03 euros (32.64 times 0.08%). The resulted merit order effect is hence very small in Nord Pool Spot. In contrast, the load forecasts for the next day presents a positive effect on the wholesale price on average. The estimated coefficient implies that if the load forecast is 1% higher then the spot price will raise as large as 0.20%, meaning that an increase in demand will be passed through disproportionately as one fifth on the spot price in the day-ahead market. Moreover, an increase in external supply from Germany and the Netherlands to Nord Pool could also reduce the Nordic system electricity price level as electricity supply is backed up by outside sources. Comparing with other electricity wholesale markets, higher proportion of hydropower and cross-border transmissions are well established in the Nordic system, which take part in determining the day-ahead prices in reaction to wind generation. More precisely, the positive sign of the Danish net imports signifies that imports relating to Denmark's scarcity in wind power generation will result in an increase in price levels and this reflects, at least to some extent, the opportunity costs of hydro usage in the other Scandinavian countries. The opposite case is true when Denmark exports under high wind penetration: the decrease in prices should reflect savings on opportunity costs of hydropower. In other words, the internal flows between Denmark, Norway and Sweden postulate a substitution between wind power and hydropower to counterbalance the intermittency of wind, preventing system prices from large fluctuations. Hence, having more hydro storage in Norway and Sweden as well as market coupling with external markets tends

to ensure a stable system price level. The way that renewables interact in the Scandinavian countries renders Nord Pool systematically steadier, while the surge of electricity prices is predominantly driven by the demand.

Turning our attention to the results of the variance equation, the day-ahead price is stabilized jointly by wind generation net coupling and net imports as they all present negative effects on price variances. In Elspot, a negative relationship between wind power and price volatility is found and a 1% increase in wind penetration reduces intraday price volatility by 0.02%. That is to say, in Elspot wind penetration not only limits the spot price from increase but also reduces associated price risks. This result may seem surprising at first and it is in contradiction to the results of some other studies (Jacobsen and Zvingilaite, 2010; Woo et al., 2011; Ketterer, 2014), but it is consistent with Jónsson et al. (2010) for the case of Denmark. This discrepancy in results concerning price volatility can be explained for the following reasons. First, this result should be analyzed together with the negative impacts of internal and external exchange flows on volatility. The well established connections in the Scandinavian region, which at the same time enable cross-border electricity trading and balance supply between hydro and wind power generation, play a role in smoothing the pattern of hourly prices by diminishing their variances. The Danish wind power facilitates both internal and external Elspot trades of electricity, in the way that it interacts with the coupling flows between Nord Pool and other markets as well as with imported electricity generated by hydropower from Norway and Sweden. Contrarily when its wind production is low, the resulting price variations may reveal the values of different sources to fill the gap of wind power generation and these values mirrored in price fluctuations may vary largely depending on whether the replacement resource is hydropower, fossil fuel or other more expensive reserves. Consequently, intraday spot prices are more oscillating during low-wind periods. This conforms to our initial suggestion that the Danish bidding zones benefit from the hydro generation in neighboring countries through power imports and exports as a means to cope with wind intermittency. Second, another potential reason to explain the difference between our results and former studies could be the use of hourly time series, which allows us to capture the finest variations in prices and the property of intermittency of wind power. It also should be claimed that the volatility in the long run might be different from the one in the short run. Therefore wind power could possibly have distinct impacts on price volatility depending on the time horizon considered. Third, it should be noted that in this study the system price of the Nord Pool Spot is used in order that interactions between wind power and hydropower come into play. The area prices in DK1 and DK2 are with no doubt more volatile than the system price due to constraints

on transmission capacities.¹⁹ Although examining volatility of area prices is clearly out of the scope of this work, it would be interesting to see if the impacts of wind power on system price volatility and area price volatility are different. These results would signal potentially how the system is constrained by transmission capacities.

3.5.4 Forecast performance

In order to provide a guidance on the accuracy of price forecasts, we split the dataset into two periods: the first period dated from March 25, 2012 to January 24, 2015 for the use of in-sample estimation and the second period starting from January 25, 2015 to March 24, 2015 for out-of-sample forecasts.²⁰ Table 3.5 displays the forecast performances of GARCH specifications under the assumptions of Gaussian and Student’s t error distributions. Overall, EGARCH model under the Gaussian and t distributions have very similar statistics and outperform conventional GARCH models. Furthermore for the selected two months’ period, EGARCH model with a Gaussian error distribution is sufficient to serve as a prediction model as it slightly outperforms EGARCH with a Student’s t error distribution and has the best out-of-sample prediction accuracy.

Table 3.5 – Comparison of out-of-sample forecasts

| Statistics | Gaussian | | Student’s t | |
|------------|----------|--------|---------------|--------|
| | GARCH | EGARCH | GARCH | EGARCH |
| RMSE | 0.0979 | 0.0378 | 0.0645 | 0.0391 |
| MAE | 0.0805 | 0.0244 | 0.0478 | 0.0246 |
| MAPE | 2.3406 | 0.7036 | 1.3798 | 0.7076 |
| TI | 0.0141 | 0.0055 | 0.0094 | 0.0057 |

Out-of-sample forecast period January 25, 2012 – March 24, 2015. RMSE, MAE, MAPE and TIC are root-mean squared error, mean absolute error, mean absolute percentage error, and Theil’s inequality coefficient respectively.

We plot the out-of-sample predictions of the price variance offered by the above EGARCH models with the two error distributions in Fig. 3.7, which shows that t distribution would generally produce larger predictions for volatility since price series are considered to have heavy tails. The results of static forecasts for the study period under the two EGARCH specifications are plotted in Fig. 3.8. Both predicted series yield very similar patterns compared

¹⁹A comparison between the Danish area prices and the system price is described in Appendix E.

²⁰The model is stable when choosing different periods for the forecasts.

with the original price series. They not only follow the general price trends but also track the evolutions of the price variations for the whole forecast period when both market fundamentals and stochastic properties of the spot prices are appropriately accounted for.

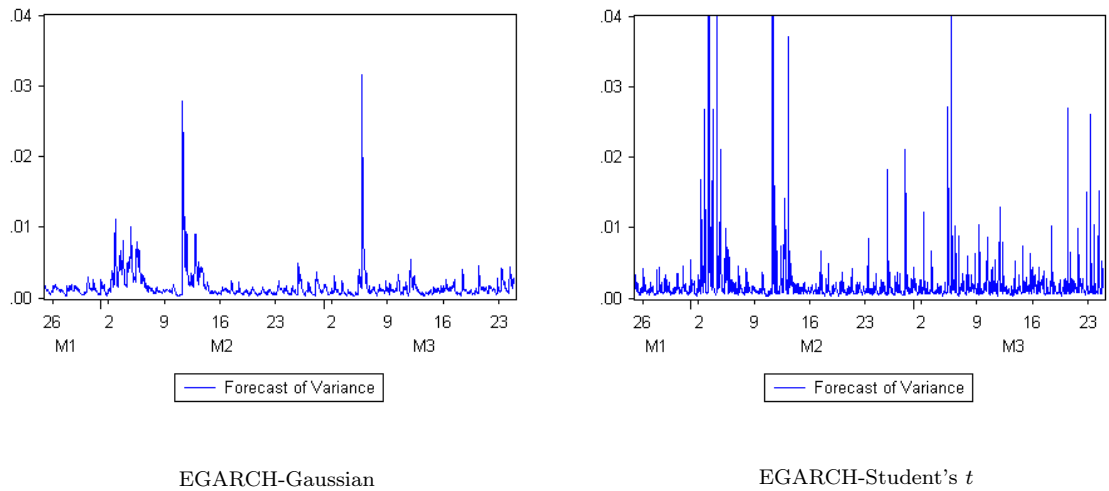


Figure 3.7 – Out-of-sample forecasts of volatility January 25, 2012 – March 24, 2015

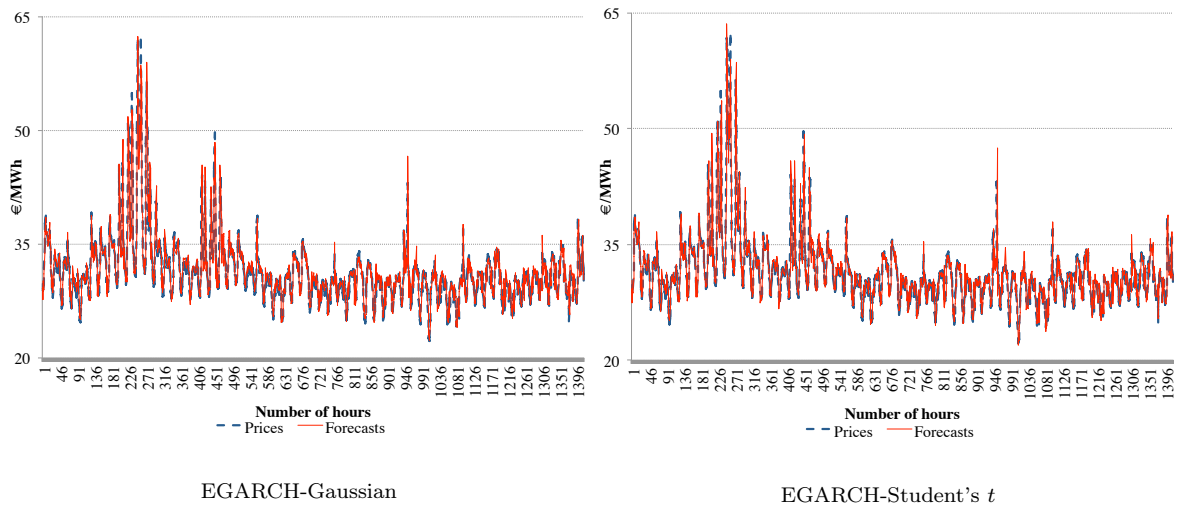


Figure 3.8 – One-step ahead forecasts of the price series January 25, 2012 – March 24, 2015

3.6 Conclusion

In this chapter, we revisit the short-term price and volatility dynamics in day-ahead electricity markets with a consideration of an increasing share of wind power generation, using the Nord Pool day-ahead market and the Danish wind generation as an example. We inspect the impacts of wind power generation and electricity cross-border exchanges on price and volatility dynamics in the Elspot electricity market by applying a GARCH process with exogenous market drivers. Cross-border exchanges are further distinguished between market coupling flows between Nord Pool and other spot markets, and import flows to Denmark from Sweden and Norway. The latter term is of importance to capture the substitution effect between wind power and hydropower in the above Nordic countries. Furthermore, we model electricity prices driven by both market-specific fundamentals and electricity price series' statistical properties in order to obtain accurate forecasts and market inferences.

As results, the price reduction effect resulted from wind penetration for the sake of merit order is very weak and the price elasticity estimated with respect to wind generation is 0.008. Meanwhile, we found evidence on that wind penetration affects negatively the diurnal price volatility in Nord Pool with an estimated elasticity of 0.02. Particularly, the price and volatility stabilization are also contributed by the coupling flows between Nord Pool and neighboring countries as well as the interexchange of hydro and wind power among Denmark, Norway and Sweden. After controlling for market fundamental drivers, an asymmetric impact of price shocks on price volatility can be found, that is, negative innovations have a larger impact on conditional variances of spot prices. Considering the fat-tail error distributional property of electricity prices can significantly increase model fits. In terms of forecasting performance, EGARCH models outperform conventional GARCH models and yield satisfying forecasts.

The centerpiece of this work highlights that the current infrastructure and market organization in Nord Pool Spot is able to handle the challenge of intermittency arose from the current amount of wind power in Denmark. The key features of Elspot to manage wind variability and uncontrollability of the wind output in the Nordic region are the reliable hydro storage accompanied with relatively flexible CHP systems and the international transmission lines within the region. The key issue here seems to be developing market integration and this casts light on the prevailing electricity market design for Nord Pool and also for other electricity systems. First, through extensive grid connections, the market effects of renewables' intermittency and variability are reduced and benefits can be created for efficient uses of other power plants (Schaber et al., 2012), namely hydro and CHP plants in the case of

Nord Pool and Denmark. Moreover, market integration can effectively improve competition (Mulder and Schoonbeek, 2013) through enlarged market size and number of competitors, and thus limit generators' ability to exercise market power especially when systems face ramping and flexibility constraints during low wind periods. Finally, geographic diversification brings in an amount of other generating capacities in other areas or regions such that security of supply can be further ensured.

Bibliography

- [1] Bollerslev, T., 1986. Generalized autoregressive conditional heteroskedasticity. *Journal of Econometrics* 31, 307-327.
- [2] Bordignon, S., Bunn, D. W., Lisi, F., Nan, F., 2013. Combining day-ahead forecasts for British electricity prices. *Energy Economics* 35, 88-103.
- [3] Bushnell, J., 2010. Building blocks: Investment in renewable and non-renewable technologies. *Harnessing Renewable Energy in Electric Power Systems: Theory, Practice, Policy*, 159.
- [4] Ciarreta, A., Espinosa, M. P., Pizarro-Irizar, C., 2014. Is green energy expensive? Empirical evidence from the Spanish electricity market. *Energy policy* 69, 205-215.
- [5] Danish Energy Agency (DEA), 2010. *Wind turbines in Denmark*, Copenhagen.
- [6] Danish Energy Agency (DEA), 2014. *Danish Climate and Energy Policy*, Copenhagen.
- [7] Delarue, E., De Jonghe, C., Belmans, R., D'haeseleer, W., 2011. Applying portfolio theory to the electricity sector: Energy versus power. *Energy Economics* 33, 12-23.
- [8] Dickey, D. A., Fuller, W. A., 1979. Distribution of the estimators for autoregressive time series with a unit root. *Journal of the American statistical association* 74, 427-431.
- [9] Ding, Z., Granger, C. W., Engle, R. F., 1993. A long memory property of stock market returns and a new model. *Journal of empirical finance* 1, 83-106.
- [10] Energinet.dk, 2014. Download of market data.
- [11] European Commission (EC), 2009. *The 2020 climate and energy package*, Brussels.

- [12] European Commission (EC), 2014. 2030 framework for climate and energy policies, Brussels.
- [13] Engle, R. F., 1982. Autoregressive conditional heteroscedasticity with estimates of variance of United Kingdom inflation. *Econometrica* 50, 987-1007.
- [14] Fanone, E., Gamba, A., Prokopczuk, M., 2013. The case of negative day-ahead electricity prices. *Energy Economics* 35, 22-34.
- [15] Forrest, S., MacGill, I., 2013. Assessing the impact of wind generation on wholesale prices and generator dispatch in the Australian National Electricity Market. *Energy Policy* 59, 120-132.
- [16] Garcia, R. C., Contreras, J., Akkeren, M. V., Garcia, J. B. C., 2005. A GARCH forecasting model to predict day-ahead electricity prices. *IEEE transactions on power systems* 20, 2.
- [17] Global Wind Energy Council (GWEC), 2014. Global figures.
- [18] Glosten, L. R., Jagannathan, R., Runkle, D. E., 1993. On the relation between the expected value and the volatility of the nominal excess return on stocks. *The journal of finance* 48, 1779-1801.
- [19] Green, R., 2012. How Denmark manages its wind power. *IAEE Energy Forum*, 3rd Quarter, 9-11.
- [20] Green, R., Vasilakos, N., 2010. Market behavior with large amounts of intermittent generation. *Energy policy* 38, 3211-3220.
- [21] Green, R., Vasilakos, N., 2012. Storing Wind for a Rainy Day: What kind of electricity does Denmark export? *Energy Journal* 33, 1-22.
- [22] Grohnheit, P. E., Andersen, F. M., Larsen, H. V., 2011. Area price and demand response in a market with 25% wind power. *Energy policy* 39, 8051-8061.
- [23] Higgs, H., 2009. Modelling price and volatility inter-relationships in the Australian wholesale spot electricity markets. *Energy Economics* 31, 748-756.
- [24] Huisman, R., Mahieu, R., 2003. Regime jumps in electricity prices. *Energy economics* 25, 425-434.

- [25] Huisman, R., Huurmana, C., Mahieu, R., 2007. Hourly electricity prices in day-ahead markets. *Energy Economics* 29, 240-248.
- [26] Huisman, R., 2008. The influence of temperature on spike probability in day-ahead power prices. *Energy Economics* 30, 2697-2704.
- [27] International Energy Agency (IEA), 2010. Projected costs of generating electricity, Paris.
- [28] International Renewable Energy Agency (IRENA), 2012. 30 Years of policies for wind energy: Lessons from 12 Wind Energy Markets.
- [29] Jacobsen, H. K., Zvingilaite, E., 2010. Reducing the market impact of large shares of intermittent energy in Denmark. *Energy policy* 38, 3403-3413.
- [30] Janczura, J., Weron, R., 2010. An empirical comparison of alternate regime-switching models for electricity spot prices. *Energy Economics* 32, 1059-1073.
- [31] Janczura, J., Trueck, S., Weron, R., Wolff, R. C., 2013. Identifying spikes and seasonal components in electricity spot price data: A guide to robust modeling. *Energy Economics* 38, 96-110.
- [32] Jónsson, T., Pinson, P., Madsen, H., 2010. On the market impact of wind energy forecasts. *Energy Economics* 32, 313-320.
- [33] Karakatsani, N. V., Bunn, D. W., 2008. Forecasting electricity prices: The impact of fundamentals and time-varying coefficients. *International Journal of Forecasting* 24, 764-785.
- [34] Ketterer, J. C. 2014. The impact of wind power generation on the electricity price in Germany. *Energy Economics* 44, 270-280.
- [35] Knittel, C. R., Roberts, M. R., 2001. An empirical examination of deregulated electricity prices. University of California Energy Institute.
- [36] Liu, H., Shi, J., 2013. Applying ARMA-GARCH approaches to forecasting short-term electricity prices. *Energy Economics* 37, 152-166.
- [37] Ljung, G. M., Box, G. E. P., 1978. On a measure of lack of fit in time series models. *Biometrika* 65, 297-303.

- [38] Lucia, J. J., Schwartz, E. S., 2002. Electricity prices and power derivatives: Evidence from the Nordic Power Exchange. *Review of Derivatives Research* 5, 5-50.
- [39] Mugele, C., Rachev, S. T., Trück, S., 2005. Stable modeling of different European power markets. *Investment Management and Financial Innovations* 3, 65-85.
- [40] Mulder, M., Schoonbeek L., 2013. Decomposing changes in competition in the Dutch electricity market through the residual supply index. *Energy Economics* 39, 100-107.
- [41] Munksgaard, J., Morthorst, P. E., 2008. Wind power in the Danish liberalised power market—Policy measures, price impact and investor incentives. *Energy policy* 36, 3940-3947.
- [42] Nelson, D. B., 1991. Conditional heteroskedasticity in asset returns: A new approach. *Econometrica: Journal of the Econometric Society*, 347-370.
- [43] Nord Pool Spot, 2015. Download centre.
- [44] Nordic Energy Regulator, 2013. Nordic Market Report 2013.
- [45] Østergaard, P. A., 2008. Geographic aggregation and wind power output variance in Denmark. *Energy* 33, 1453-1460.
- [46] Phillips, P. C. B. and Perron, P., 1988. Testing for a Unit Root in Time Series Regressions. *Biometrika* 75, 335-346.
- [47] Sadorsky, P., 2012. Correlations and volatility spillovers between oil prices and the stock prices of clean energy and technology companies. *Energy Economics* 34, 248–255.
- [48] Schaber, K., Steinke, F., Hamacher, T., 2012. Transmission grid extensions for the integration of variable renewable energies in Europe: Who benefits where? *Energy Policy* 43, 123-135.
- [49] Sperling, K., Hvelplund, F., Mathiesen, B. V., 2010. Evaluation of wind power planning in Denmark – Towards an integrated perspective. *Energy* 35, 5443-5454.
- [50] Steggals, W., Gross, R., Heptonstall, P., 2011. Winds of change: How high wind penetrations will affect investment incentives in the GB electricity sector. *Energy policy* 29, 1389-1396.

- [51] The European Wind Energy Association (EWEA), 2010. Wind energy and electricity prices. Exploring the merit order effect.
- [52] Thomas, S., Mitchell, H., 2005. GARCH Modeling of High-Frequency Volatility in Australia's National Electricity Market. Discussion Paper. Melbourne Centre for Financial Studies.
- [53] Traber, T., Kemfert, C., 2011. Gone with the wind? – Electricity market prices and incentives to invest in thermal power plants under increasing wind energy supply. *Energy Economics* 33, 249-256.
- [54] Twomey, P., Neuhoff, K., 2010. Wind power and market power in competitive markets. *Energy policy* 38, 3198-3210.
- [55] Weron, 2009. Heavy-tails and regime-switching in electricity prices. *Mathematical Methods of Operations Research*, 69(3), 457-473.
- [56] Woo, C. K., Horowitz, I., Moore, J., Pacheco, A., 2011. The impact of wind generation on the electricity spot-market price level and variance: The Texas experience. *Energy Policy* 39, 3939-3944.
- [57] Worthington, A., Kay-Spratley, A., Higgs, H., 2005. Transmission of prices and price volatility in Australian electricity spot markets: a multivariate GARCH analysis. *Energy Economics* 27, 337-350.
- [58] Zakoian, J. M., 1994. Threshold heteroskedastic models. *Journal of Economic Dynamics and control* 18, 931-955.

Appendices

Appendix A. Seasonality of the Elspot electricity price

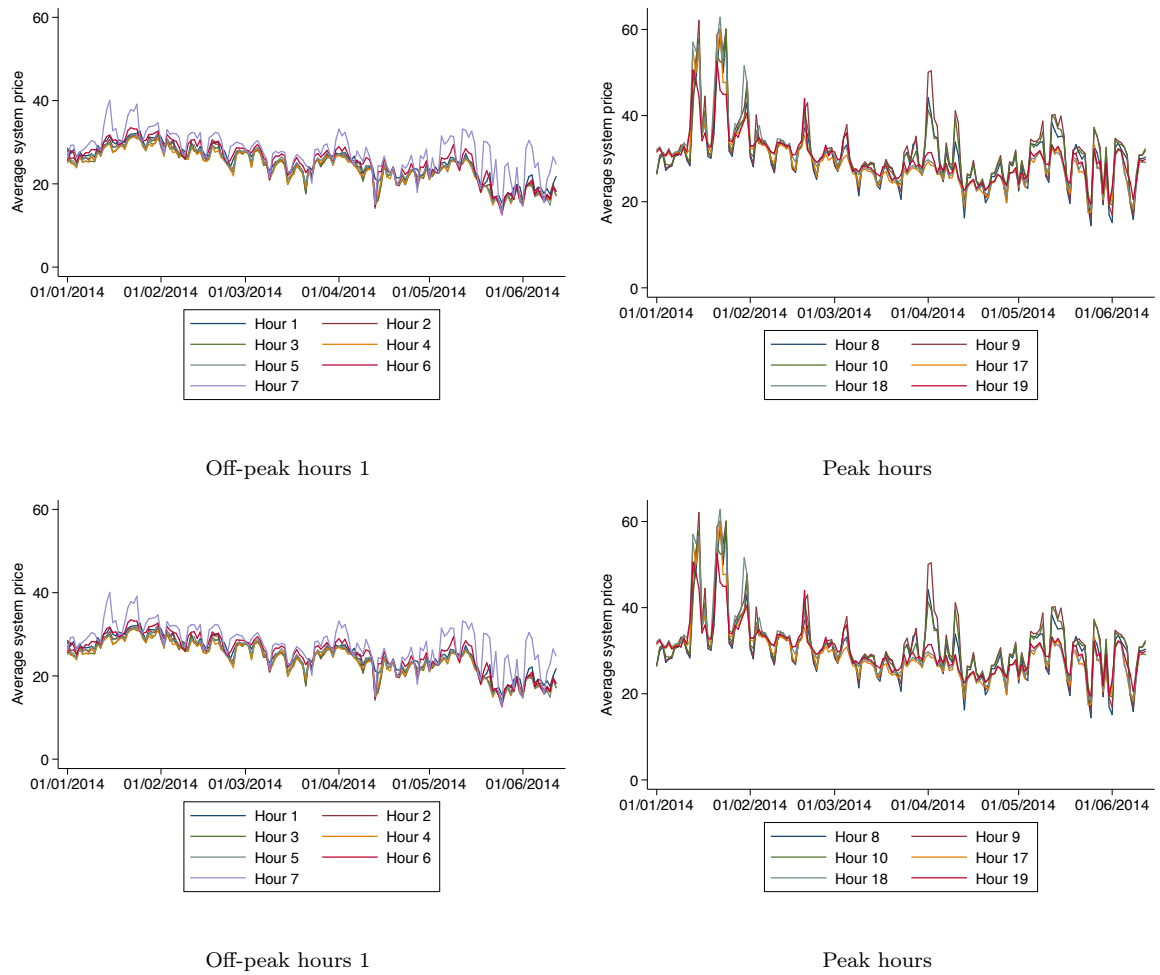


Figure A.1: Hourly patterns of the Nord Pool system prices from January 1, 2014 to June 30, 2014 (€/MWh). Data source: Author's realization based on energinet.dk (2015).

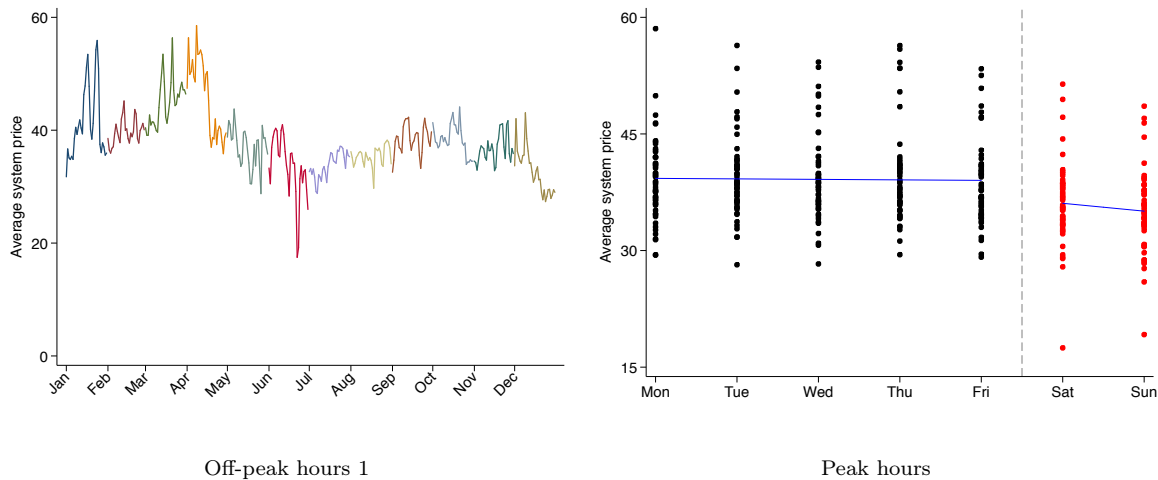


Figure A.2: Monthly and weekday/weekend patterns of average daily prices (€/MWh). Data source: Author's realization based on energinet.dk (2015).

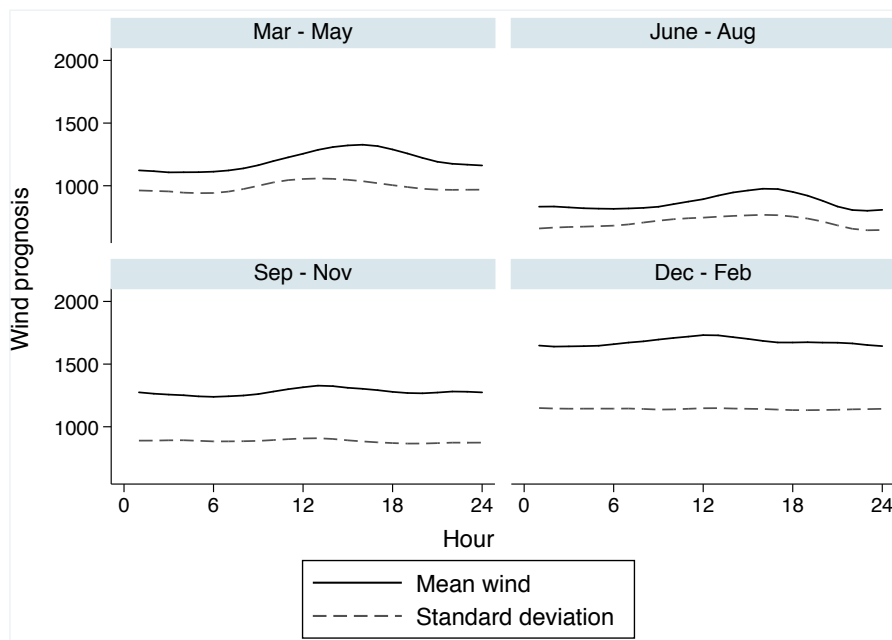


Figure B.1: Seasonal and hourly profiles of wind generation prognosis. Data source: Author's calculation based on Nord Pool Spot (2015).

Appendix B. Seasonal and hourly variations of wind power prognosis

Appendix C. Estimation results with a linear deseasonalization process

Since a linear deseasonalization process is very sensitive to extreme values, we define outliers as price levels exceeding the range of 5-100€/MWh. The range considered largely surpasses

three times of standard deviation relative to the average.²¹ After all, there are 77 observations are detected as extreme events, whose number is very small compared to the total number of observations. Thus the price values identified as outliers are replaced by the mean prices averaged over 24 and 48 hours before and 24 and 48 hours after in order to smooth the overall price series.

The fitted spot prices at time t are derived by taking out the seasonal fixed effects in the following form:

$$P_t = \beta_0 + \sum_{i=2}^{24} \beta_{1,i} H_{i,t} + \sum_{j=1}^6 \beta_{2,j} D_{j,t} + \sum_{l=2}^{12} \beta_{3,l} M_{l,t} + \sum_{p=2013}^{2014} \beta_{4,p} Y_{p,t} + \beta_5 Hol_t + \varepsilon_t \quad (3.9)$$

where H_t , D_t , M_t , Y_t and Hol_t are dummy variables for hours of day, days of week, months, years and national holidays in Denmark. The estimated results are shown in Table C.1.

The estimated results of an ARMA-GARCH process are summarized in Table C.2,²² where the first column presents the results of the specification with only wind and consumption forecasts included. The second and the third columns represent the estimation results by adding the net coupling between Nord Pool and other spot markets as well as the Danish net import from Norway and Sweden. Column (4) presents the results of the overall impact in Elspot of the wind to load ratio. Compared with the estimation results obtained after applying wavelet decomposition and smoothing, most of estimates remain robust except for the variable net import in the mean equation.

Appendix D. TGARCH, GJRGARCH and GARCH specifications with a Generalized Error Distribution (GED)

To test the robustness of the asymmetric impacts of innovation terms on volatility, a threshold GARCH (TGARCH) (Zakoian, 1994), and a Glosten-Jagannathan-Runkle GARCH (GJR-GARCH) (Glosten et al., 1993) processes are also applied. TGARCH and GJRGARCH are

²¹As electricity price is specifically more volatile than other commodities' prices and price spikes happen often to reflect generation scarcity relative to demand, we did not apply the outlier filter as 3 times of standard deviation (Ketterer, 2014) in order to allow for more variations of the spot price. This process is applied another time to the fitted value of electricity spot prices later.

²²To conserve space, only AR and MA order 1 are reported in Table C.2. The orders included in the regression of Column (3) are AR(1), AR(2), AR(5), AR(16), AR(17), AR(24), AR(25), MA(1), MA(2), MA(3), MA(24), MA(25), MA(49), MA(73), MA(167), MA(168) and MA(169).

Table C.1: Estimated coefficients for removing seasonality

| Var. | Coef. | Var. | Coef. | Var. | Coef. | Var. | Coef. |
|-----------|-----------|------|----------|------|-----------|----------|-----------|
| Hour 2 | -1.027*** | Mon | 4.157*** | Feb | 1.173*** | 2013 | 7.206*** |
| Hour 3 | -1.645*** | Tue | 4.379*** | Mar | -3.622*** | 2014 | -5.498*** |
| Hour 4 | -1.899*** | Wed | 4.683*** | Apr | -2.718*** | Holiday | -3.522*** |
| Hour 5 | -1.523*** | Thu | 4.445*** | May | -6.607*** | Constant | 30.65*** |
| Hour 6 | -0.145 | Fri | 3.628*** | Jun | -10.22*** | | |
| Hour 7 | 2.057*** | Sat | 0.871*** | Jul | -16.74*** | | |
| Hour 8 | 5.479*** | | | Aug | -11.02*** | | |
| Hour 9 | 7.064*** | | | Sep | -8.439*** | | |
| Hour 10 | 6.509*** | | | Oct | -4.043*** | | |
| Hour 11 | 5.973*** | | | Nov | -5.010*** | | |
| Hour 12 | 5.484*** | | | Dec | -2.486*** | | |
| Hour 13 | 4.828*** | | | | | | |
| Hour 14 | 4.286*** | | | | | | |
| Hour 15 | 3.927*** | | | | | | |
| Hour 16 | 3.795*** | | | | | | |
| Hour 17 | 4.385*** | | | | | | |
| Hour 18 | 5.828*** | | | | | | |
| Hour 19 | 5.632*** | | | | | | |
| Hour 20 | 4.703*** | | | | | | |
| Hour 21 | 3.691*** | | | | | | |
| Hour 22 | 3.007*** | | | | | | |
| Hour 23 | 2.188*** | | | | | | |
| Hour 24 | 0.627* | | | | | | |
| R-squared | 0.502 | | | | | | |

OLS regression with seasonal dummies. Asterisks indicate significance at *** $p < 0.01$, ** $p < 0.05$, * $p < 0.1$. Hour 1 (00:00-01:00), Sunday, January, the year 2012, and non-holiday days are set as references.

close ideas to allow the conditional standard deviation and variance to depend upon the sign of the lagged innovations. Specifically, a TGARCH(1, 1) specification is expressed as follows:

$$\sigma_t = \omega + \alpha|\varepsilon_{t-1}| + \gamma|\varepsilon_{t-1}|I(\varepsilon_{t-1} < 0)\beta\sigma_{t-1} + Z_t'\pi$$

Similarly a GJRGARCH(1, 1) may be expressed as:

$$\sigma_t^2 = \omega + \alpha\varepsilon_{t-1}^2 + \gamma\varepsilon_{t-1}^2I(\varepsilon_{t-1} < 0) + \beta\sigma_{t-1}^2 + Z_t'\pi$$

where $I = 1$ if $\varepsilon_{t-1} < 0$, and 0 otherwise. Therefore, in these two specifications, the

parameter γ also captures the asymmetric aspect of innovations. However, in the contrary to the EGARCH model in order to produce larger impacts with negative innovations, γ needs to be positive. As seen in Table D.1, GJRGARCH performs relatively poorly compared with other GARCH models while TGARCH provides good model fits. As a result, the parameter γ measuring asymmetric effects is indeed negative in these specifications.

Finally, a Generalized Error Distribution can serve as an alternative to model fat tails of the price series. The estimation and prediction results are presented in Table D.2 and Table D.3, respectively.

Appendix E. Comparisons between the Danish area prices and the system price

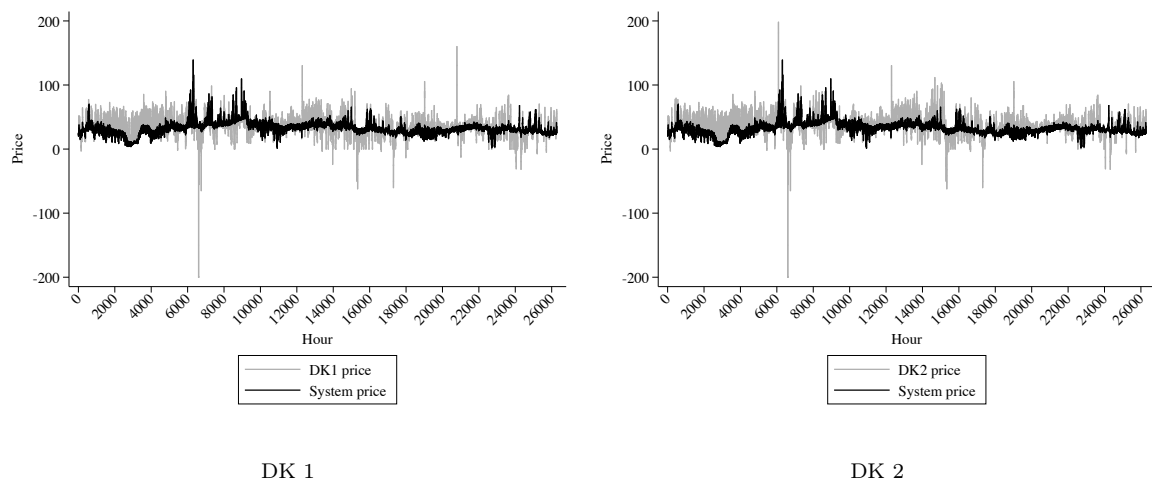
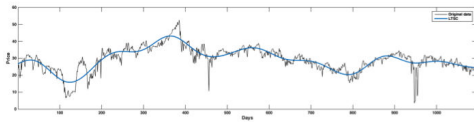


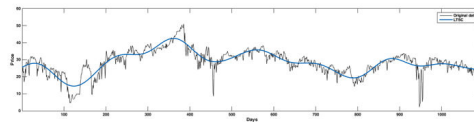
Figure E.1: Comparisons between Danish area prices and the system price Data source: Author's calculation based on Nord Pool Spot (2015).

Appendix F. Unit root tests for stationarity of the variables

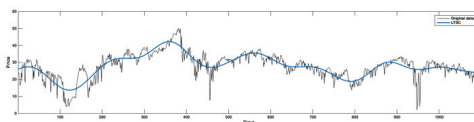
Appendix G. Deseasonalized day-ahead prices without LTSC by wavelet decomposition and smoothing for all 24 hours



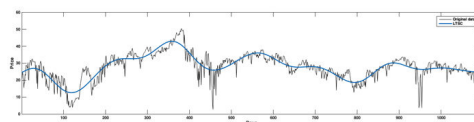
Hour 1



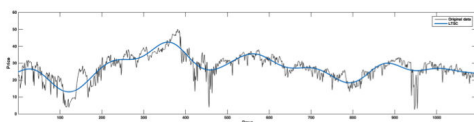
Hour 2



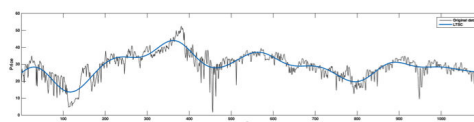
Hour 3



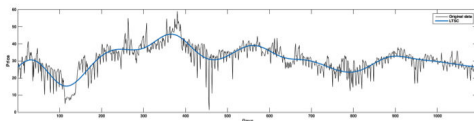
Hour 4



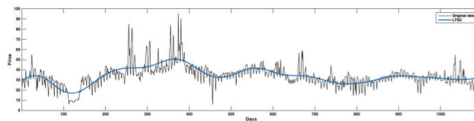
Hour 5



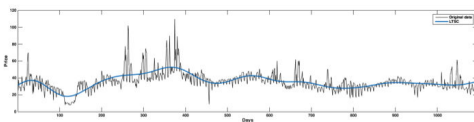
Hour 6



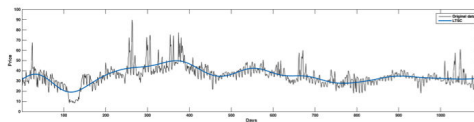
Hour 7



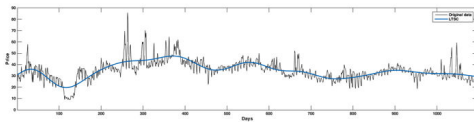
Hour 8



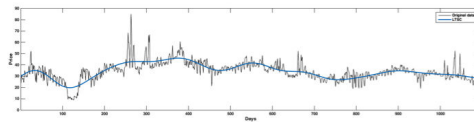
Hour 9



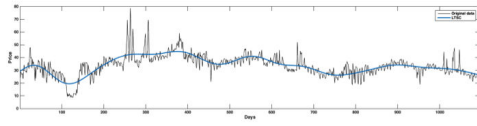
Hour 10



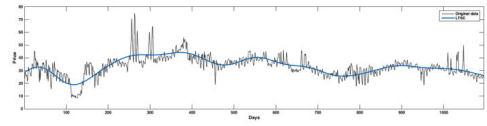
Hour 11



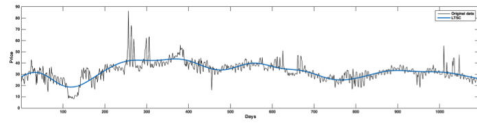
Hour 12



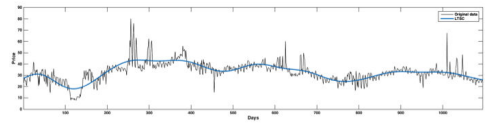
Hour 13



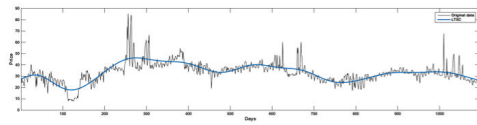
Hour 14



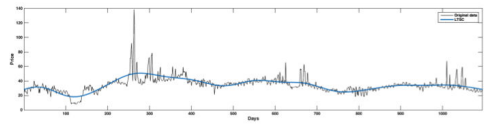
Hour 15



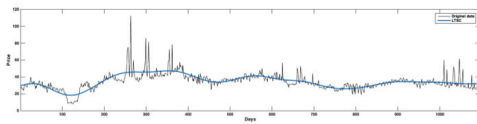
Hour 16



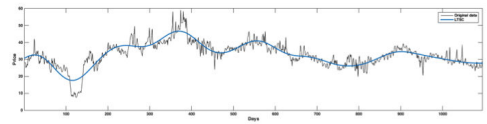
Hour 17



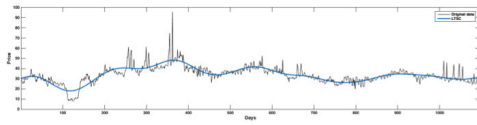
Hour 18



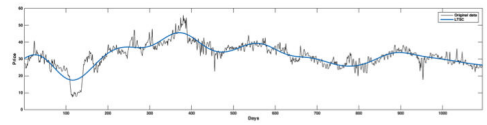
Hour 19



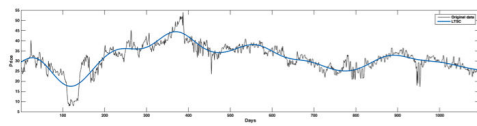
Hour 20



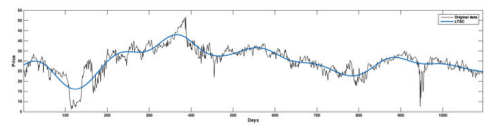
Hour 21



Hour 22



Hour 23



Hour 24

Figure G.1: LTSC estimation for each hour.

Table C.2: Estimated coefficients for hourly price equation and variance equation

| | | Model specification | | | | |
|----------------------|--------------------------|-----------------------|------------------------|------------------------|------------------------|-------|
| | | (1) | (2) | (3) | (4) | |
| Mean equation | Wind | -0.02401*** (0.00) | -0.02327*** (0.00) | -0.03410*** (0.00) | | |
| | Load | 0.14141*** (0.00) | 0.02265*** (0.00) | 0.20320*** (0.00) | | |
| | Coupling | | -0.00002*** (0.00) | -0.00003*** (0.00) | -0.00003*** (0.00) | |
| | Import | | | -0.00001*** (0.00) | -0.00001*** (0.00) | |
| | Wind share | | | | -1.54232*** (0.00) | |
| | Constant | 2.04030*** (0.00) | 3.24865*** (0.00) | 1.30770*** (0.00) | 3.34985*** (0.00) | |
| | AR(1) | 0.95370*** (0.00) | 0.97383*** (0.00) | 0.51089*** (0.00) | 0.97564*** (0.00) | |
| | MA(1) | 0.21165*** (0.00) | 0.18986*** (0.00) | 0.51972*** (0.00) | 0.19191*** (0.00) | |
| | Variance equation | Wind | -0.00002*** (0.00) | -0.00002*** (0.00) | -0.00090*** (0.00) | |
| | | Load | 0.00024*** (0.00) | 0.00026*** (0.00) | -0.00153*** (0.00) | |
| Coupling | | | -2.95E-08*** (0.00) | -3.40E-07*** (0.00) | -1.63E-07*** (0.00) | |
| Import | | | | -4.18E-07*** (0.00) | -1.65E-07*** (0.00) | |
| Wind share | | | | | -0.00531*** (0.00) | |
| Constant | | -0.00199*** (0.00) | -0.00222*** (0.00) | 0.02384*** (0.00) | 0.00054*** (0.00) | |
| ARCH(1) | | 0.80671*** (0.00) | 0.97593*** (0.00) | 0.44023*** (0.00) | 0.84283*** (0.00) | |
| GARCH(1) | | 0.23163*** (0.00) | 0.20622*** (0.00) | 0.15419*** (0.00) | 0.24943*** (0.00) | |
| Model fits | | Adj. R2 | 0.95 | 0.95 | 0.95 | 0.95 |
| | | AIC | -3.70 | -3.80 | -3.53 | -3.83 |
| | BIC | -3.69 | -3.79 | -3.52 | -3.82 | |
| | ARCH test | 0.03 | 0.16 | 0.24 | 0.13 | |

Wind share is the ratio of wind prognosis in load.

Table D.1: Estimation results with TGARCH and GJRGARCH

| Mean Equation | Gaussian | | Student's t | |
|--------------------------|--------------|--------------|---------------|--------------|
| | TGARCH | GJR-GARCH | TGARCH | GJRGARCH |
| δ | 3.432*** | -0.012 | 1.138*** | -0.002 |
| Wind | -0.010*** | -0.011*** | -0.008*** | -0.014*** |
| Coupling | -7.11e-06*** | 7.16e-06*** | -9.84e-06*** | -4.94e-06*** |
| Import | 3.25e-06*** | 2.27e-05*** | 3.62e-06*** | 9.33e-06*** |
| Load | 0.023*** | 0.339*** | 0.209*** | 0.330*** |
| AR(1) | 1.247*** | 0.521*** | 1.290*** | 0.352*** |
| Variance Equation | | | | |
| ω | 0.005*** | 0.004*** | 0.056*** | 0.011*** |
| α | 0.233*** | 0.275*** | 0.645*** | 0.239*** |
| β | 0.782*** | 0.641*** | 0.271*** | 0.510*** |
| γ | 0.098*** | 0.164*** | 0.044** | 0.105*** |
| v | | | 2.671*** | 20.000*** |
| Wind | -0.001*** | -1.27e-04*** | -1.58e-04 | -2.53e-04*** |
| Coupling | -5.92e-07*** | -9.93e-08*** | -6.04e-07*** | -1.54e-07*** |
| Import | -6.23e-07*** | -9.91e-08*** | -8.40e-07*** | -1.69e-07*** |
| Load | 8.62e-05 | -2.51e-04*** | -0.004*** | -8.38e-04*** |
| R2 | 0.94 | 0.90 | 0.94 | 0.88 |
| Adjusted R2 | 0.94 | 0.90 | 0.94 | 0.88 |
| LL | 54401 | 47800 | 59076 | 48115 |
| AIC | -4.14 | -3.64 | -4.50 | -3.66 |
| BIC | -4.13 | -3.63 | -4.49 | -3.65 |
| DW stat. | 2.14 | 0.80 | 2.22 | 0.66 |
| ARCH test | 0.00 | 0.00 | 0.99 | 0.00 |

Wind is the log hourly wind generation forecasts for Denmark. Coupling is the net flow of electricity from Germany to Nord Pool Spot. Import is the net flow of electricity from Norway and Sweden to Denmark. Load is log the consumption forecasts in Nord Pool. Asterisks indicate significance at *** $p < 0.01$, ** $p < 0.05$, * $p < 0.1$. LL, AIC and BIC are log likelihood, Akaike Information and Bayesian Information Criteria respectively. ARCH test reports the P-value by testing the null hypothesis of no ARCH effects.

Table D.2: Estimation results with a GED

| Mean Equation | GARCH | EGARCH | TGARCH | GJRGARCH |
|-------------------|--------------|--------------|--------------|--------------|
| δ | 1.473*** | 1.470*** | 1.373*** | 0.002 |
| Wind | -0.008*** | -0.008*** | -0.007*** | -0.010*** |
| Coupling | -9.71e-06*** | -9.24e-06*** | -9.30e-06*** | 1.49e-05*** |
| Import | 4.01e-06*** | 4.33e-06*** | 4.29e-06*** | 3.09e-05*** |
| Load | 0.177*** | 0.176*** | 0.185*** | 0.329*** |
| AR(1) | 1.295*** | 1.290*** | 1.282*** | 0.119*** |
| Variance Equation | | | | |
| ω | 0.001*** | -2.007*** | 0.023*** | 0.014*** |
| α | 0.763*** | 0.766*** | 0.536*** | 0.206*** |
| β | 0.189*** | 0.625*** | 0.291*** | 0.590*** |
| γ | | -0.025** | -0.031* | 0.082*** |
| GED dist. | 0.873*** | 0.867*** | 0.871*** | 1.984*** |
| Wind | -2.04e-05*** | -0.046** | -5.49e-04*** | -0.001*** |
| Coupling | -2.67e-08*** | -4.93e-05*** | -6.54e-07*** | -2.86e-07*** |
| Import | -2.85e-08** | -6.27e-05*** | -7.78e-07*** | -3.46e-07 |
| Load | -4.45e-05 | -0.080** | -8.15e-04 | -0.001*** |
| R2 | 0.94 | 0.94 | 0.94 | 0.72 |
| Adj. R2 | 0.94 | 0.94 | 0.94 | 0.72 |
| LL | 58699 | 58592 | 58690 | 36320 |
| AIC | -4.47 | -4.46 | -4.47 | -2.76 |
| BIC | -4.46 | -4.45 | -4.46 | -2.76 |
| DW stat. | 2.22 | 2.23 | 2.21 | 0.31 |
| ARCH test | 0.79 | 0.88 | 0.99 | 0.00 |

Wind is the log hourly wind generation forecasts for Denmark. Coupling is the net flow of electricity from Germany to Nord Pool Spot. Import is the net flow of electricity from Norway and Sweden to Denmark. Load is the log consumption forecasts in Nord Pool. Asterisks indicate significance at *** $p < 0.01$, ** $p < 0.05$, * $p < 0.1$. LL, AIC and BIC are log likelihood, Akaike Information and Bayesian Information Criteria respectively. ARCH test reports the P-value by testing the null hypothesis of no ARCH effects.

Table D.3: Forecast evaluation of GARCH specifications with a GED

| | GARCH | EGARCH | TGARCH | GJRGARCH |
|------|--------|--------|--------|----------|
| RMSE | 0.0619 | 0.0391 | 0.0391 | 0.1188 |
| MAE | 0.0450 | 0.0245 | 0.0245 | 0.0981 |
| MAPE | 1.2968 | 0.7058 | 0.7054 | 2.8558 |
| TI | 0.0090 | 0.0057 | 0.0057 | 0.0171 |

Out-of-sample forecast period January 25, 2012 – March 24, 2015. RMSE, MAE, MAPE and TIC are root-mean squared error, mean absolute error, mean absolute percentage error, and Theil's inequality coefficient respectively.

Table E.1: Area prices in DK1 in comparison with the system prices

| Price DK1 | Frequency | % |
|-----------|-----------|-------|
| Equal | 5,630 | 21.42 |
| Lower | 9,835 | 37.42 |
| Higher | 10,815 | 41.15 |

Area prices of DK1 are assumed to be different from the system price when their differences exceed 0.1€/MWh.

Table E.2: Area prices in DK2 in comparison with the system prices

| Price DK1 | Frequency | % |
|-----------|-----------|-------|
| Equal | 6,280 | 23.9 |
| Lower | 6,208 | 23.62 |
| Higher | 13,792 | 52.48 |

Area prices of DK2 are assumed to be different from the system price when their differences exceed 0.1€/MWh.

Table F.1: Results of unit root tests

| Variables | ADF | PP |
|-----------|--------|--------|
| Price | -27.34 | -28.17 |
| Wind | -14.95 | -19.63 |
| Load | -14.01 | -19.37 |
| Coupling | -31.04 | -29.57 |
| Import | -25.22 | -24.8 |

ADF and PP stand for the augmented Dickey-Fuller test and Phillips-Perron test, respectively. The null hypothesis is that the variable contains a unit root. The critical values for 1%, 5% and 10% quantiles are -3.43, -2.86 and -2.57, respectively.

Chapter 4

Wind power integration: Wind up with continuous intraday electricity markets?

1 *

¹This chapter is based on a revised version for a resubmission to *the Energy Journal*, and the working paper: Karanfil, F., Li, Y., 2015. Wind up with continuous intraday electricity markets? The integration of large-share wind power generation in Denmark. Chaire European Electricity Markets.

4.1 Introduction

Wind power is the fastest growing electricity-generating technology among renewable energy sources, and its development plays an essential role in the current worldwide energy transition from fossil fuels to clean energy due to its ecological benefits. However, bridled at wind power's pre-eminence, electricity systems are confronting numerous challenges with regard to renewable integration and system stability resulted from high volatility and low predictability of wind generation. Since the deregulation of electricity markets in Europe, short-term market design has gradually divided electricity trading into several sequential markets with different time horizons. In contrast to quite common day-ahead trading schemes in many countries, intraday trading mechanisms have come into operation rather recently in the Nordic and some Western European electricity markets. Chronologically, generators can decide freely to sell their production one day before the day of operation (in day-ahead electricity markets) and/or to continue to trade close to the time of physical delivery, if the day-ahead planning needs to be corrected or reset (in intraday electricity markets). As wind outputs depend highly on meteorological conditions, which are subject to a limited predictability, the real schedule of wind power may deviate from the output planned in day-ahead markets. Closer to real time than the day-ahead trading, especially, the use of intraday trading allows wind generators (and other participants in the market) to modify their day-ahead production schedules according to updated and improved forecasts after the closure of the day-ahead market. Therefore, the intraday trading is regarded as an important tool to handle intermittent wind, and to foster its integration into the electricity system.

In the light of an increasing importance of the intraday market, the present chapter is pioneering and well timed to provide a sound analysis based on this market design. The aims of this chapter are: first, to explain how intraday prices deviate from the day-ahead ones; second, to investigate the fundamental drivers that cause these deviations; and third, to show how wind forecast errors are dissolved. We propose a novel approach involving conventional econometric techniques to test for causality among the fundamental components of an intraday market in order to examine the market functionality. More specifically, by using Danish data, we explore causal links and interactions among the price differences between the intraday and day-ahead markets, and the deviations or forecast errors² of the real wind generation, conventional

²More precisely, other factors can also contribute to consumption or production deviations. For example, a generator may have an incentive to overstate or understate the production level in order to influence the spot prices or to trade electricity strategically in different markets to benefit from arbitrages. In this context, it may not be appropriate to call the quantity differences as "errors", as

generation, and total demand compared with their committed day-ahead amounts, as well as the cross-border electricity trade in the Nordic intraday trading system. Time series techniques are applied to the data for two different trading zones in Denmark, namely Denmark West (DK1) and Denmark East (DK2).

Denmark is widely considered as a role model for the deployment of wind energy. This makes Denmark an ideal case to study the market influence of large wind penetration. Setting a high bar of wind integration in the coming years, the Danish short-term renewable target involves an achievement of 50% wind power in final consumption by 2020, and its long-term national goal requires complete independence from fossil fuels by 2050. Fig. 4.1 displays the evolutions of the accumulated installed wind power capacity and the share of wind feed-in in Denmark. As seen in Fig. 4.1, since 2009, both the installed wind capacity and the share of wind power in final consumption have been steadily growing.

Due to the rapid development of wind power, the impacts of wind generation on electricity prices and volatility in day-ahead markets have gained considerable popularity recently (see, for example, among others, Rintamäki et al., 2014; Pereira and Rodrigues, 2014; Stefano et al., 2015). Fabbri et al. (2005) analyzed the costs of wind forecast errors associated with the day-ahead wholesale market, but their model was built without considering an intraday trading mechanism. Indeed, the phenomena of massive price volatility and merit order effect³ as a consequence of growing wind generation fed in the electricity system are, with no doubt, worth studying. However, up to now, the important role of a close-to-real-time trading mechanism (i.e. an intraday market), which is an essential market tool for handling the uncertainties posed by wind power in the electricity supply, has been overlooked. In contrast to the majority of studies concerning renewable power that have focused on day-ahead electricity markets, in this chapter we focus on an intraday electricity market, and seek to investigate its role in responding to the aforementioned three types of forecast errors. It should be declared that the econometric techniques used here are not new in economic literature, but the originality of this work comes from the unprecedented idea of investigating the functionality of an intraday market through causality tests. While a high level of liquidity has been viewed as a standard criterion for the effectiveness of an intraday market by some scholars (Weber, 2010; Furió et al., 2009), we have a different viewpoint: instead of focusing on the level of liquidity or intraday trade volumes, an intraday market can be considered effective if causality between

they result from such behavior. However, for linguistic simplification, we use production/consumption deviations and forecast errors interchangeably in this chapter.

³The merit order effect describes the lowering of power prices at the power exchange due to an increased supply of renewable energies.

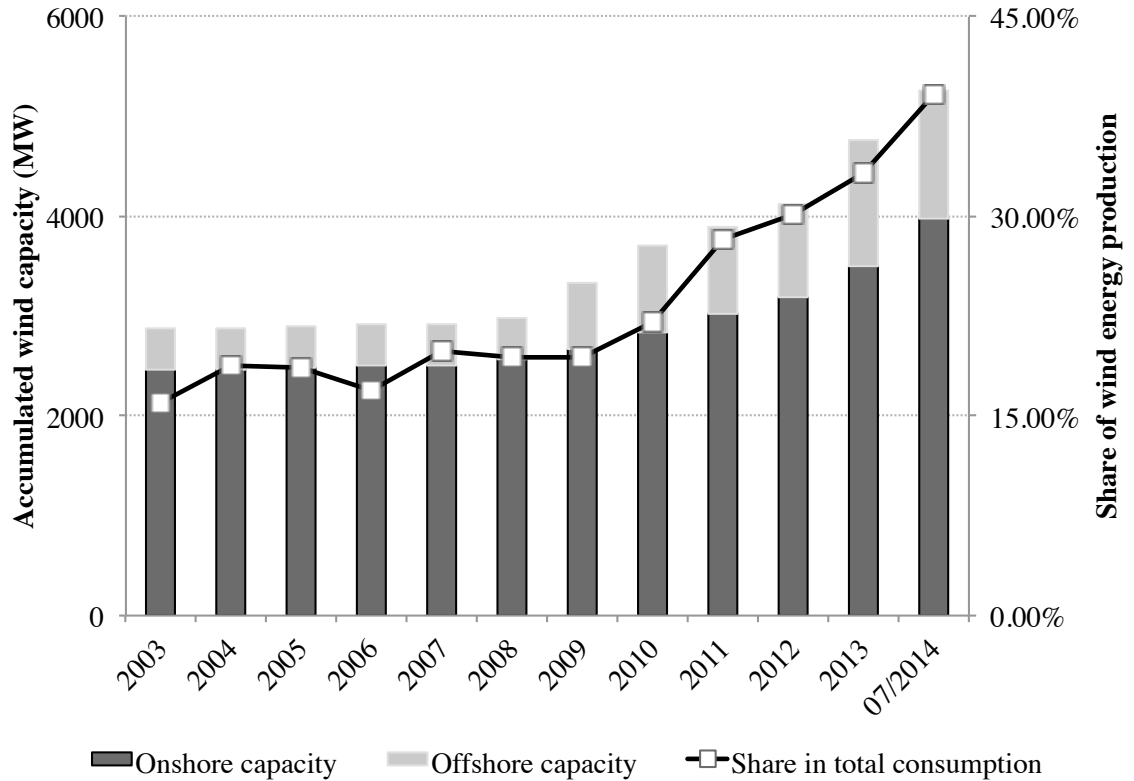


Figure 4.1 – Accumulated wind capacity onshore/offshore (left axis) and wind power as a percentage of total electricity consumption (right axis) 2003 – July 2014. Data sources: Authors’ realization based on Danish Wind Industry Association (2014) and Danish Energy Agency (DEA) (2015).

price signals and market fundamentals can be established. To this end, our study distinguishes itself from all previous work, and it contributes to the literature at least in the following three aspects. First, it aims at providing the first empirical evidence on intermittent impacts of the Danish wind penetration on the intraday electricity market, and at showing how wind forecast errors affect intraday prices relative to day-ahead prices. Second, it investigates the causal relationships between the deviations in wind generation, fossil-based electricity generation, and electricity consumption from their day-ahead schedules as well as cross-border exchanges in the intraday market. The idea of studying these causal links is that they indicate how the paths of other market elements would differ in response to wind uncertainty in order to settle system imbalances, and to ensure supply security. Third, it provides further simulations based on impulse response functions in order to shed light on the persistence and duration of

the price and quantity divergences resulted from a shock to forecast errors. The analysis of impulse response functions has been carried out, for example, by Aatola et al. (2013) in the market of European emission allowances in order to investigate dynamic relationships between carbon forward and other energy commodity price series. In this chapter, compared with former studies, a deeper, but straightforward interpretation of the impulse responses about the functionality of the intraday market goes beyond the statistical links among time series. As noted by Henriot (2014), an ideal intraday mechanism should not be targeting at a high trading volume *per se*, because economic agents behave according to the incentives that they receive from price signals. By the same token, this chapter supports the author's argument, and more importantly, makes an innovation on testing the functionality of an intraday electricity market.

The rest of the chapter is organized as follows. Section 4.2 summarizes the literature related to wind integration and intraday designs. Section 4.3 introduces market mechanisms in the Nordic power market. Section 4.4 describes the dataset as well as the estimation method to be used in this study. Empirical results and discussions are presented in Sections 4.5 and 4.6, respectively. Finally, Section 4.7 concludes.

4.2 Literature review

Up to date, there is only a limited amount of research undertaken on the roles of intraday electricity markets, and even less when it comes to econometric research. The goal of intraday trading is to enable market participants to improve their positions following improvements in forecasts with respect to those already taken in the day-ahead market. As mentioned very recently by Hirth et al. (2015), the integration costs of wind power are presented by three components, namely temporal variability, uncertainty, and location constraints. Since electricity is not economically storable, and its supply and demand must be met instantaneously at the moment of physical delivery, wind producers' ability to reset a generation agenda with a short-lead time in an intraday market can effectively reduce both system costs for balancing and uncertainty on allocation of transmission capacities induced by lowered forecast errors (Borggrefe and Neuhoff, 2011; Chaves-Ávila et al., 2013; Hiroux and Saguan, 2010; Smeers, 2008). For instance, before the integration of Denmark into the Nordic intraday market, Holtinen (2005) had already pointed out that the introduction of this shorter lead-time trading scheme would help the Danish wind producers to deliver better forecasts. Besides reducing both uncertainty and system costs, an electricity market participant may also favor the use of

intraday trading for other two reasons – to avoid using expensive balancing services together with to prevent penalties of imbalances imposed by the Transmission System Operator (TSO) (Bourry and Kariniotakis, 2009).⁴

Regardless of the potential benefits of intraday trading, low liquidity has been observed across several European intraday markets. A few scholars have offered the following explanations to this low liquidity issue. Chaves-Ávila et al. (2013) mentioned that the lack of liquidity is due to that most of the generators prefer to commit their production long ahead of time in the consideration of start-up costs and generation planning. However, this is not the case for wind generators as generation forecasts become more accurate when moving forward in time. Henriot (2014) suggests that oscillating predictions resulting in high trading costs can deter market players from participating in intraday markets. Using Danish data, Mauritzen (2015) separated between wind shortfalls and surpluses, and suggested that the former would increase the probability of intraday trades while the latter would do the opposite due to the poorly designed Electricity Supply Act of 1999, which imposed a purchase obligation on the transmission system operator, and thus granted to the wind farms built before 2003 an exemption of balancing costs for a period of 10 years. Besides, the less transparent pay-as-bid trading scheme of the intraday design may make market participants fear that their purchases or sales would affect the market price, and cause losses relative to the undisturbed price level. Therefore, the perspective of surpassing the intraday liquidity barrier is regarded as a cornerstone to improving the overall efficiency of market design (Weber, 2010).

Setting the day-ahead price as an “indifferent offer price”, which implies that generators are not making extra profits by trading additionally in intraday markets, forecast errors and their directions become fundamental variables in determining intraday transactions (Von Selasinsky, 2014). Particularly, because the penetration of wind generation in power systems depends largely on the costs of intermittency, it is important to take into account differences between intraday and day-ahead prices, since the additional gains or losses need to reflect system scarcity, and in turn, the true economic value added by wind power depends on this (Borenstein, 2012; Joskow, 2011). As a potential indicator of liquidity (Hagemann and Weber, 2013), intraday price deviations are found to be significant in most of the trading hours in the Spanish market (Furió et al., 2009), whereas Ito and Reguant (2014) report that the arbitrage behavior of wind producers in both markets contributes to a positive day-ahead market

⁴For a wind farm located in the North West of Denmark with installed capacity of 18MW, the authors showed that for a Danish wind producer, participation in the intraday market reduces the imbalance penalties by 18%.

premium. Recent econometric work by Hagemann (2013) investigates the fundamentals that drive the intraday price deviations in Germany, and shows that renewable forecast errors can significantly differ the intraday prices from the day-ahead values. However, as yet, none of these studies have examined causal relationships between price deviations and different sources of forecast errors altogether, or the persistence of forecast errors in intraday markets.

4.3 Market settings

Nord Pool Spot operates both the Elspot day-ahead and the Elbas intraday markets mainly in the Nordic (Denmark, Finland, Norway, and Sweden) and Baltic (Estonia, Latvia and Lithuania) regions.⁵ A timeline illustrating the Nord Pool and the Danish successive trading scheme in the day-ahead, intraday, and balancing markets is shown in Fig. 4.2. Contrary to Elspot, where prices are settled by a marginal rule through an hourly uniform-price auction, after the day-ahead gate closure at 12:00 CET, Elbas functions as a continuous market where trading takes place from 14:00 CET on the day before the day of operation up to one hour before physical delivery. Particularly, the intraday prices are set based on a first-come, first-served principle, that is, buyers and sellers choose directly the bids to be accepted in the market (Nord Pool Spot, 2015). The Danish day-ahead and intraday markets are a part of the Nord Pool electricity system, and the Danish TSO Energinet.dk is responsible for maintaining physical balances in the electricity system. It is quite important to mention that, as a fundamental principle of the Danish market model, market participants (consumers, producers, and electricity traders), including wind generators, are the Balancing Responsible Parties (BRP), meaning that they are financially liable for their own imbalances (Energinet.dk, 2011).⁶ Next, during and posterior to the day of operation, a balancing market, which can be partitioned into a regulating and balancing power market, deals with the rest of imbalances. In the regulating power market, Energinet.dk purchases (upward regulation) or sells (downward regulation) electricity through BRPs in the common Nordic regulating power market. After the delivery hour, remaining incurred imbalances are neutralized financially by the TSO in the balancing power market (Energinet.dk, 2008).⁷

⁵Nord Pool Spot also operates a day-ahead market called N2EX in the United Kingdom.

⁶It is possible that a player does not hold balance responsibility, but in this case, she must assign it to a BRP. In practice, balancing is mostly achieved from the supply side, and consumers generally assign this obligation to electricity suppliers.

⁷Since balancing power does not represent a market mechanism, and involves only financial settlements, in the rest of this chapter we refer the terms balancing and balancing market solely to the

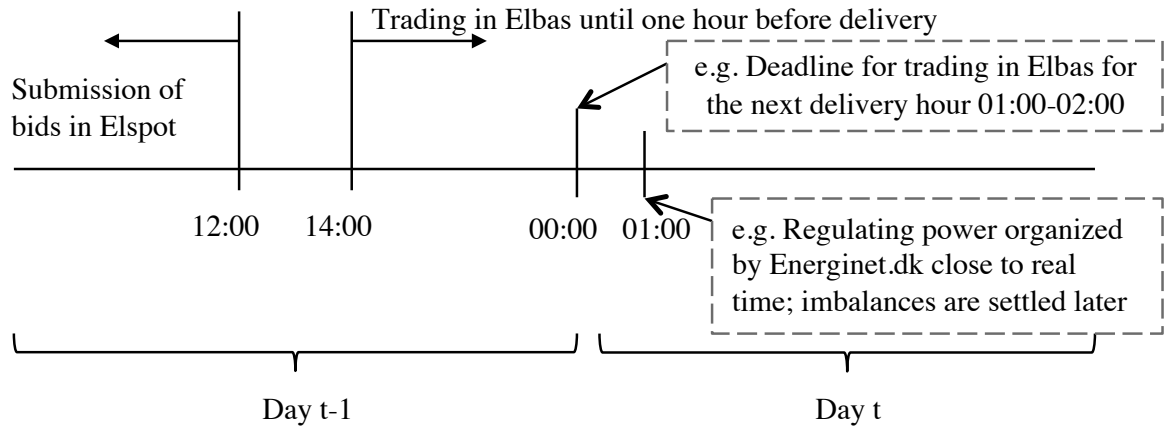


Figure 4.2 – Timeline of the Nordic sequential electricity trading.

Because of the existence of transmission constraints, the Nordic market is often divided into various bidding areas that have in general the area prices different from the system prices, reflecting transmission scarcities. Denmark is also divided into two bidding areas: Denmark West and Denmark East. Both of them have well-established connections with neighboring countries.⁸

4.4 Methods

4.4.1 Data sources

The Elspot day-ahead prices and the Elbas market prices are measured in euro per megawatt hour (€/MWh) in the two Danish bidding zones, retrieved from the Danish TSO Energinet.dk (2014). As mentioned in Section 4.3, since Elbas is operated as a continuous pay-as-bid market, for each hour, the information on the realized maximal, minimal, and average area prices is available.

While the share of wind generation fed in the system in Denmark predominates the world's record, almost all the rest of electricity generation in the country comes from combined heat

 regulating power market.

⁸The two bidding zones were completely separated before 2010 until the commission of the Great Belt Power Link with a transmission capacity of 600MW.

and power (CHP) plants. Among these plants, local CHP plants tend to follow actively heat demand rather than bid in the electricity market, but primary CHP plants are the principal players in the electricity market (Green and Vasilakos, 2012). Accordingly, wind forecast errors and primary CHP forecast errors are calculated as the difference between the realized productions and the day-ahead forecasted values. Analogously, consumption forecast errors are the deviations of the realized total consumption from the scheduled load. Forecast data are obtained from Nord Pool Spot (2014) and production data are sourced from Energinet.dk (2014) for both DK1 and DK2.

Just as stated in the previous section, Denmark has extensive international transmission lines with its neighbors. Besides a market coupling built on the Danish-German border, both DK1 and DK2 are also well connected with their Scandinavian neighboring countries, namely Sweden and Norway, whose providential hydropower can counterbalance fluctuations of the intermittent generation, in case needed. Consequently, to take into account the influence of international electricity flows, using data from Nord Pool Spot, the net Elbas import flows are calculated based on the Elbas cross-border flows between a Danish bidding zone (DK1 or DK2) and its exchange partner. All quantity variables are measured in megawatt hour (MWh). Finally, the dataset to be used covers the period from January 1, 2012, to May 31, 2014, containing 21,168 observations with hourly frequency, and each day has a length of 24 hours.

4.4.2 Data descriptions

Wind forecast errors

In order to have an impression on the magnitude of wind forecast errors, Fig. 4.3 plots their distributions in DK1 and DK2. The majority of the wind forecast errors fluctuate around zero by 500 MWh in Denmark West, and by 250 MWh in Denmark East. The difference in magnitudes between these two zones can be explained by the fact that wind farms are more concentrated in the former region. The distributions in both regions do not appear to be symmetric. More importantly, Fig. 4.3 shows that the wind output deviations hold a mean close to zero.

Detailed statistics of the wind forecast errors are listed in Table 4.1, according to which, indeed, the means and medians of the wind forecast errors are relatively small. They are negative in Denmark West, but positive in Denmark East. The observed excess kurtosis in both regions means that the wind forecast errors are more concentrated in a near-zero interval

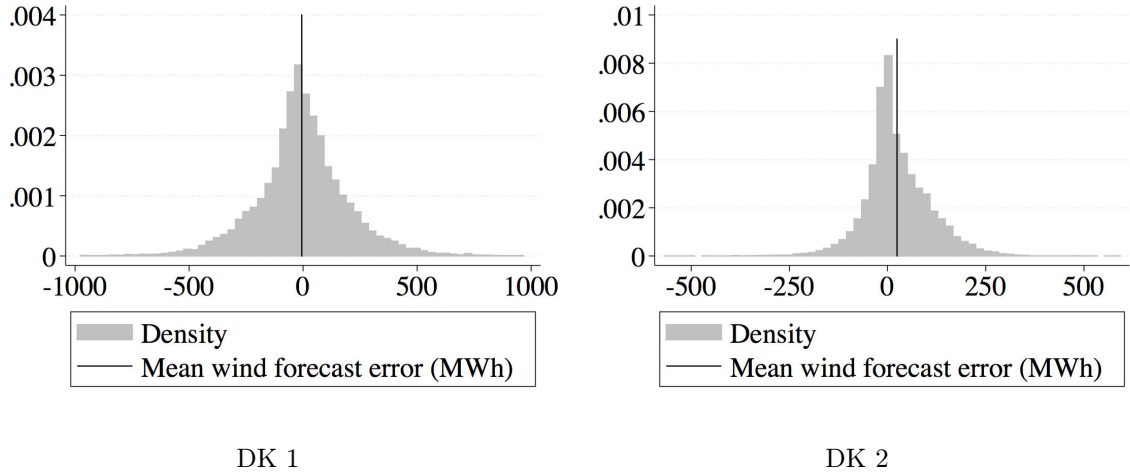


Figure 4.3 – Distributions of wind forecast errors in DK1 and DK2. Data sources: Authors’ realization based on Energinet.dk (2014) and Nord Pool Spot (2014).

compared with a normal distribution. Since the changes of wind outputs rely on weather conditions rather than market elements, they are exogenous to the electricity trading system. We would expect that the wind forecast errors are so if wind generators could truly report their expectations on the production schedules. In the case of Denmark, the assumption of the exogeneity and independence of wind forecast errors has been recently verified by Mauritzen (2015). Although a few exceptions may exist for this assumption, it is likely to be valid in the case of wind power.⁹ Hence, taking wind forecast errors as exogenous to the system, their correlations with market variables should have causal interpretations.

Besides wind forecast errors, summary statistics for the other variables involved in the analysis can be found in Tables A.1 and A.2 in Appendix A.¹⁰

⁹The incentive to untruthfully report the expected value of wind production can be a violation of this exogeneity assumption. However, the ability of verification of the TSO, and the existence of subsidies make this situation unlikely. Moreover, the plausible dependence of wind forecast errors to wind power, consumption forecast errors, and market coupling can be ruled out by data analyses. For more details, see Mauritzen (2015).

¹⁰Note that outages may be an influential factor on intraday market trading. We do not separate this factor given the low incident frequency. Furthermore, since we measure the deviation of the realized CHP production from its day-ahead schedule, the unplanned breakdowns are actually incorporated in this variable.

Table 4.1 – Summary statistics of wind forecast errors

| Zones | Mean | S.D. | Med. | Max. | Min. | Skew. | Kurt. | Nb. positive | Nb. negative | Nb. zero |
|-------|-------|--------|--------|---------|----------|-------|-------|-----------------|-----------------|-------------|
| DK1 | -5.92 | 207.38 | -10.00 | 1237.00 | -1643.00 | -0.10 | 6.15 | 9923 | 11188 | 57 |
| DK2 | 24.05 | 83.62 | 10.00 | 592.00 | -569.00 | 0.27 | 5.70 | 12147 | 8840 | 181 |

Summary statistics of the mean, standard deviation, median, maximum, minimum, skewness, kurtosis and numbers of observations with positive, negative and zero values of the wind forecast errors in each bidding zone.

Day-ahead – intraday differences

The intraday market Elbas is exerting a growing importance as more wind power enters the grid. Table 4.2 presents the number of hours when trade takes place in Elbas as a percentage of total number of hours in both Western and Eastern Denmark. It follows from Table 4.2 that both areas have achieved fairly good liquidity in intraday trading. The percentages of intraday usage have been rising during the period of the study. As the scales of generated electricity and installed wind capacity in Denmark West are larger than those in Denmark East, it is not surprising that the intraday market of DK1 is more liquid in terms of trade occurrences.

Table 4.2 – Intraday trading hours as a percentage of total hours.

| Bidding zone | 2012 | 2013 | 2014 |
|--------------|--------|--------|--------|
| DK1 | 72.51% | 77.91% | 88.22% |
| DK2 | 61.16% | 62.37% | 72.43% |

Very high (or very low) intraday-day-ahead price differences generally represent costs and urgency of using balancing services. For this economic reason, extreme prices should be left untouched in data treatment. For those hours when no trade occurs in the intraday market, the intraday prices are displayed as zero at the Nord Pool power exchange. Showing these data, Fig. 4.4 inspects the differences between the intraday and day-ahead electricity prices.¹¹ It is easy to observe, quite frequently, a noticeable day-ahead price premium in both bidding zones.

¹¹On June 7th, 2013, DK1 reached the technical maximum curtailment price of 2000 €/MWh. This was due to revisions on thermal power plants that coincided with grid maintenance, and low wind power production at the same time (NER, 2014). The five hourly day-ahead prices affected by this event are replaced by the prices averaged over the same hours one day before and one day after.

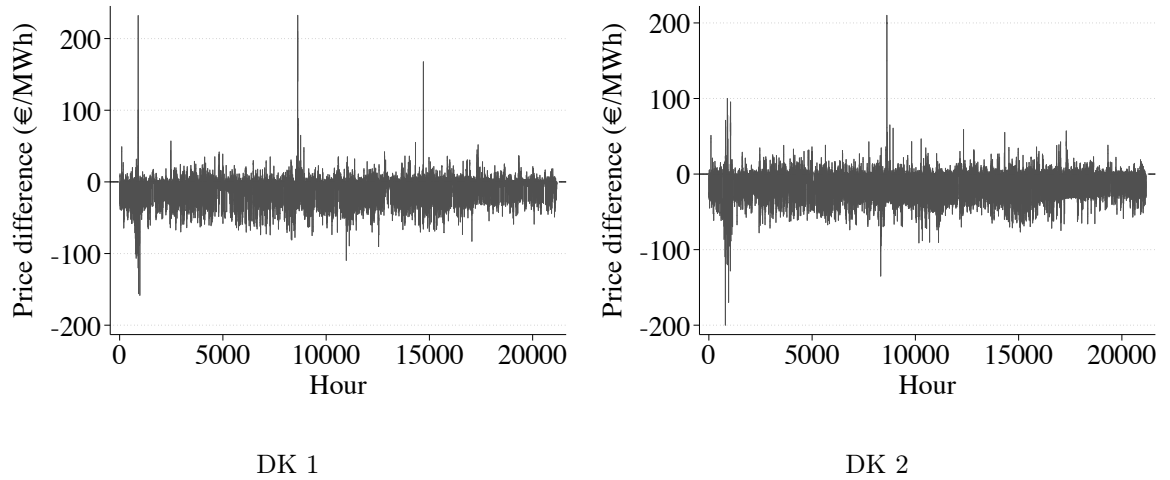


Figure 4.4 – The difference between the intraday and day-ahead prices observed at Nord Pool Spot. Data sources: Authors’ realization based on Energinet.dk (2014) and Nord Pool Spot (2014).

If the prognosis of the wind output is accurate enough, it should not be a daunting task to handle the intermittent energies only in the day-ahead market. However, often, recurrent wind forecast errors nudge electricity systems toward trade imbalances after the day-ahead transactions have occurred. By the nature of this market design, such imbalances should be reflected by the price differences between the day-ahead and intraday markets, if forecast errors are mainly managed through the intraday mechanism. However, in the case where the intraday prices are set to zero because of insufficient liquidity (i.e. no trade takes place), the price differences between the intraday and day-ahead markets can no longer reflect the additional system costs as these costs are nil at the stage of intraday trading. As mentioned in Section 4.2, spreads between intraday and day-ahead prices should correctly reflect system scarcities and true economic values added by renewable energies (Borenstein, 2012; Joskow, 2011). Relying on this rationale, to estimate a reasonable and accurate econometric model, we thus consider the price differences between the intraday and day-ahead markets as zero when there is no electricity traded in the intraday market.¹²

The price differences after this data adjustment in DK1 and DK2, which will be used in

¹²An alternative way of thinking is that the shadow intraday prices need to satisfy a no-arbitrage condition when they are displayed as zero due to non-occurrence of trade in the intraday market. In this case, generators are at least indifferent between trading in Elspot and in Elbas in order not to deviate from their behavior of the day-ahead trading. This implies that the implicit intraday prices should be equal to the day-ahead prices, which makes the price differences between them to be zero.

estimations, are presented in Fig. 4.5. In contrast to Fig. 4.4, positive and negative price spreads are distributed more randomly around zero, which can be further confirmed according to the summary statistics in Tables A.1 and A.2 in Appendix A, where the means and medians of the price differences are close to zero, and the numbers of negative and positive observations are balanced. One may expect that the Elbas intraday price often exceeds considerably the day-ahead price to reflect the scarcity of the available generation as electricity trade approaches to real time. However, compared with the day-ahead prices, intraday prices spike very few times during the whole period. In contrast, the intraday prices plunged several times, especially at the beginning of the study period in DK2. Fig. 4.5 shows that on average, the close-to-real-time trading is not more expensive than the day-ahead trading, and therefore, balancing generation assets are not scarce in the Nordic area. This is to some extent understandable since the abundant hydro reserves in Scandinavian countries may dampen the interest of close-to-real-time trades, because electricity is, as a matter of fact, stored in the form of water. As will be discussed in Section 4.6, cross-border power exchanges play indeed an important role in the functioning of the intraday market and wind integration in Denmark.

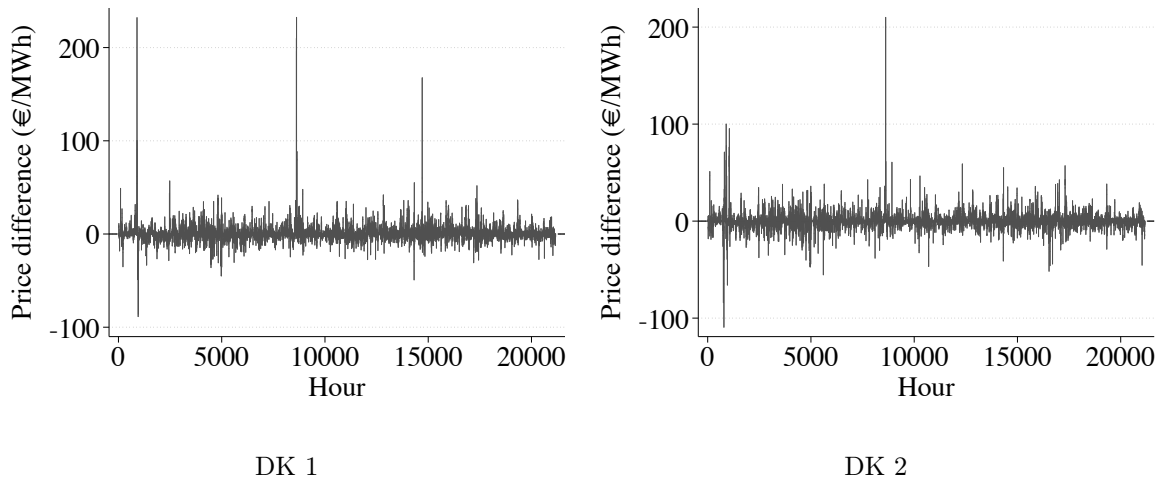


Figure 4.5 – The difference between the intraday and day-ahead prices to be used for modeling. Data sources: Authors’ realization based on Energinet.dk (2014) and Nord Pool Spot (2014).

The lack of generation scarcities in the Nordic electricity market can be further verified by means of a scatter plot of the hourly price differences between the intraday and day-ahead markets against the total electricity generation. It follows from Fig. 4.6 that the hourly price divergences stay stable even when the total generation becomes very large.

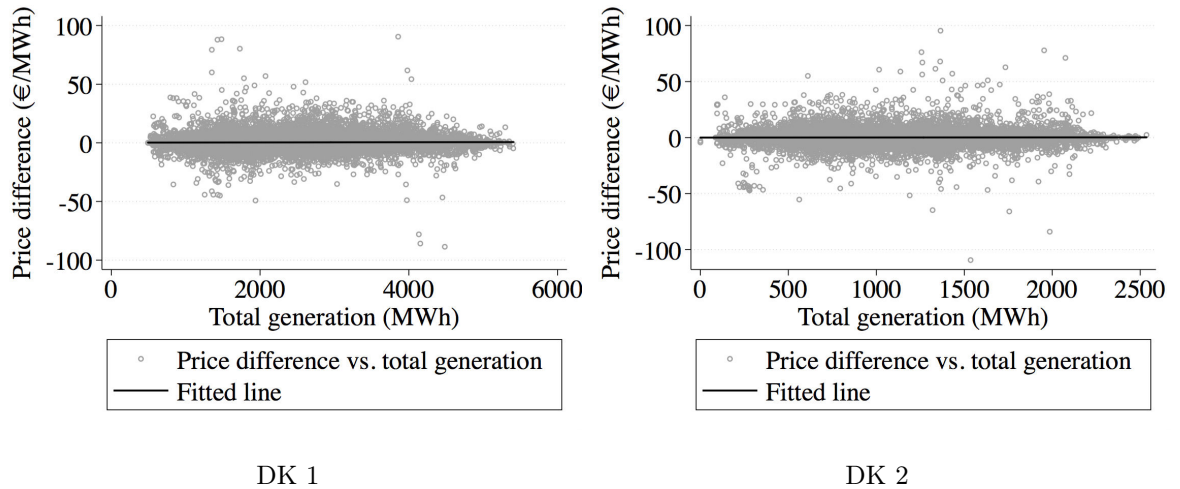


Figure 4.6 – Price differences versus total generation in DK1 and DK2. Data source: Authors’ realization based on Nord Pool Spot (2014).

Additionally, a static investigation on the relationship between the price spreads and the forecast errors may help us to understand both the necessity and utility of dynamic modeling, which is what we turn to next. In order to do so, in Fig. 4.7 we provide a scatter plot with ordinary least squares (OLS) regression line of the correlation between the price differences and the total system imbalances (i.e. the sum of all forecast errors in wind generation, conventional generation, and final consumption). The intraday price deviations are stable around zero, reasonably implying that the three sources of individual imbalances interact to each other in order to reduce the aggregate system imbalances. In the same vein, a decreasing trend of the price spread can be noticed in Fig. 4.8, which depicts the intraday price deviations as a function of forecast errors only in wind generation. It is important to note that although some useful insights can be extracted from Figs. 4.7 and 4.8, the relationships displayed here by means of OLS regression lines are just static pictures of temporally interrelated variables. As a consequence, the use of a model that is able to capture this temporal dynamics, and to describe more accurately the trajectories of the intraday price signal in response to the imbalances in the electricity system is motivated in the next section.

4.4.3 Empirical methodology

We use time series techniques to address the research questions that are raised in the introductory section. For this purpose, a dynamic multivariate model can be specified, and then

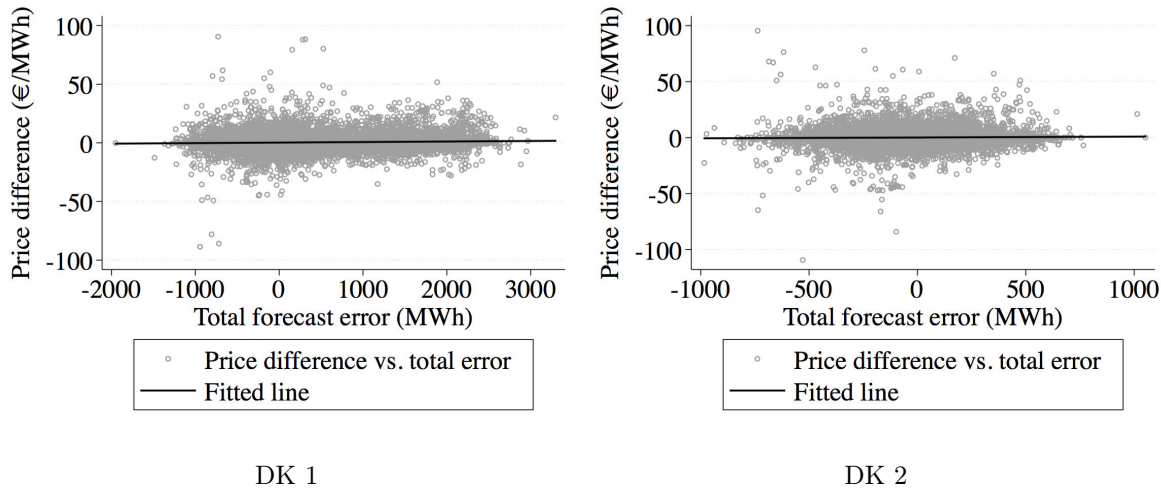


Figure 4.7 – Price differences versus total forecast errors in DK1 and DK2. Data source: Authors’ realization based on Nord Pool Spot (2014).

estimated. But before proceeding to the model, time series properties of the data should be examined in order to avoid any spurious estimation result. We apply the generalized least squares (GLS) augmented Dickey-Fuller test (DF-GLS) proposed by Elliott et al. (1996), and additional three GLS versions of the modified Phillips-Perron (1988) tests developed by Ng and Perron (2001). In fact, the DF-GLS test is based on the standard Dickey and Fuller (1979) and Said and Dickey (1984) unit root tests, and it has the following form:

$$\Delta y_t = \beta_0 y_{t-1} + \sum_{i=1}^k \beta_i \Delta y_{t-i} + \varepsilon_t \quad (4.1)$$

where y_t is a local-to-unity GLS detrended series.¹³ Then the DF-GLS test consists of testing the null hypothesis of non-stationarity (i.e. $\beta_0 = 0$) against the alternative hypothesis of stationarity (i.e. $\beta_0 < 0$) by using a standard t test from an OLS estimate of Eq. (4.1). Elliott et al. (1996) showed that this strategy of GLS detrending of the data provides substantial power gains over the standard unit root tests. On the other hand, the unit root tests of Ng and Perron (2001), called the M tests, follow also the same strategy as in Elliott et al. (1996), and provide further improvements in terms of size and power properties. Indicating that in the case of unit root tests, the conventional procedures of lag length selection for the

¹³Since these unit root tests are widely used and understood in the time series literature, we do not repeat here in detail the presentation of their estimation strategies.

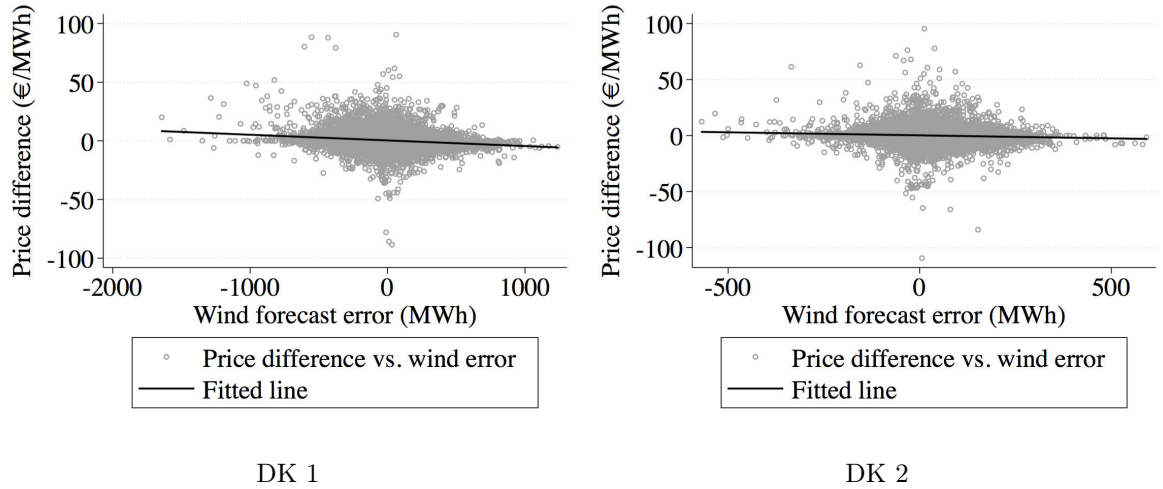


Figure 4.8 – Hourly price differences versus wind forecast errors in DK1 and DK2. Data source: Authors’ realization based on Nord Pool Spot (2014).

autoregressive terms (such as Akaike Information Criterion (AIC) or Bayesian Information Criterion (BIC) are not sufficiently flexible, Ng and Perron (2001) also developed a modified information criterion (MIC), which is then shown to be more robust in the presence of negative moving average errors.

Once the order of integration of the variables is established, one can proceed to the model. In the case where the variables are all found to be stationary, the dynamic relationship between them should be estimated in a vector autoregressive (VAR) framework. The VAR model including the five variables under examination can be presented in the following form:

$$y_t = \Gamma_0 + \Gamma_1 y_{t-1} + \Gamma_2 y_{t-2} + \dots + \Gamma_p y_{t-p} + \varepsilon_t \quad (4.2)$$

where $y_t = (Price_dif_t, Wind_er_t, CHP_er_t, Load_er_t, Flow_t)'$ is a vector of dependent variables in which *Price_dif* stands for the difference between the average hourly intraday prices and day-ahead prices; *Flow* represents net cross-border electricity flows; *Wind_er*, *CHP_er*, and *Load_er* denote respectively wind forecast errors, primary CHP forecast errors, and consumption forecast errors, as discussed above. Still in Eq. (4.2), ε_t is a (5×1) vector of i.i.d. white noises, Γ_0 is a (5×1) vector of constant terms, and Γ_i are (5×5) parameter matrices including coefficients associated with the lagged values of endogenous variables for $i = 1, \dots, p$. The optimal lag length p can be determined using the AIC. To investigate the causal relationships between two variables in the sense of Granger causality (Granger, 1969), the

joint significance of the coefficients in Γ_i associated with a given independent variable should be tested. If some of these parameters are found to be statistically significant, this indicates that the dependent variable is caused by the independent variable under consideration. In this respect, the Wald statistics, which follow the chi-square distribution with degrees of freedom equal to the number of parameter restrictions, provide an accurate measure of significance. Thus, causal links can be explored by applying the Wald test to the estimated coefficients in Γ_i matrices.

Although the VAR model given in Eq. (4.2) can provide the required information about the causal relationships among the series, it cannot indicate how each variable responds to innovations in other variables, and how long the effect lasts. Using the estimation results of Eq. (4.2), the generalized impulse response (GIR) analysis developed by Koop et al. (1996) and Pesaran and Shin (1998) can be used to address this issue. Basically, a GIR function measures the effect of one standard error shock to an equation in the system given in Eq. (4.2) at time t on the expected values of y at time $t + n$. By doing so, it provides an efficient way to evaluate the effects of different forecast errors on electricity price deviations, and possibly vice versa. It should be added that the GIR analysis is not sensitive to the ordering of variables in the VAR system.

4.5 Results

As discussed above, in the first step of our empirical analysis, we test for a unit root by using the DF-GLS test (Elliot et al, 1996) and the M tests (Ng and Perron, 2001). The results are given in Table 4.3.

From Table 4.3 it follows that all series under consideration are stationary for both of the trading zones in Denmark (i.e. Denmark West, DK1; Denmark East, DK2), that is they are integrated of order 0 (i.e. an $I(0)$ process). Hence, the conventional Granger causality test can be performed in the case of a VAR framework, which should involve all of these variables in their levels.

We estimated the VAR system given in Eq. (4.2), and then tested the joint significance of the parameters in order to assess the causal links between the variables. The results are depicted in Table 4.4.¹⁴

According to Table 4.4, the answer to one of the research questions of this chapter con-

¹⁴Recall that wind forecast errors are included as an exogenous variable in the VAR. The results are robust to standard robustness checks, which are not reported here to conserve space.

Table 4.3 – Unit root test results

| | Variables | DF-GLS | MZ _α -GLS | MZ _t -GLS | MSB-GLS |
|-----|-----------|----------|----------------------|----------------------|---------|
| DK1 | Price_dif | -19.84** | -499.8** | -15.80** | 0.031** |
| | Wind_er | -13.80** | -361.0** | -13.43** | 0.037** |
| | CHP_er | -13.36** | -486.9** | -15.60** | 0.032** |
| | Load_er | -7.793** | -104.7** | -7.229** | 0.069** |
| | Flow | -16.62** | -596.6** | -17.26** | 0.028** |
| DK2 | Price_dif | -21.93** | -806.3** | -20.07** | 0.024** |
| | Wind_er | -16.37** | -654.8** | -18.09** | 0.027** |
| | CHP_er | -12.20** | -297.4** | -12.19** | 0.040** |
| | Load_er | -2.734** | -14.91** | -2.681** | 0.179* |
| | Flow | -16.40** | -600.9** | -17.33** | 0.028** |

DF-GLS is the modified version of the augmented Dickey-Fuller test suggested by Elliott et al. (1996); MZ_α-GLS is the modified Phillip-Perron MZ_α test; MZ_t-GLS is the modified Phillip-Perron MZ_t test; MSB-GLS is the modified Sargan-Bhargava test which is also given by a ratio between MZ_α-GLS and MZ_t-GLS (i.e. MSB-GLS= MZ_t-GLS/ MZ_α-GLS). For all tests, lag lengths are chosen using the modified AIC (MAIC) suggested by Ng and Perron (2001). * and ** denote the rejection of the null hypothesis of unit root at the 5% and 1%, respectively.

Table 4.4 – Results of Granger causality

| | Dep. Var. | Price_dif | Wind_er | CHP_er | Load_er | Flow |
|-----|-----------|-----------|----------|---------|---------|---------|
| DK1 | Price_dif | - | 92.17** | 57.57** | 45.99* | 36.49 |
| | CHP_er | 38.71 | 330.5** | - | 27.85 | 94.91** |
| | Load_er | 57.71** | 57.31** | 60.25** | - | 32.50 |
| | Flow | 33.23 | 123.6** | 108.4** | 24.11 | - |
| DK2 | Price_dif | - | 62.12** | 106.6** | 24.06 | 47.10** |
| | CHP_er | 45.85** | 121.0** | - | 157.8** | 76.25** |
| | Load_er | 40.30* | 85.14** | 156.1** | - | 29.07 |
| | Flow | 56.02** | 113.75** | 78.02** | 24.23** | - |

χ^2 -statistics are given for the hypothesis that the coefficients associated with the relevant variables are jointly zero. * and ** denote the rejection of the null hypothesis of non causality at the 5% and 1% respectively.

cerning the fundamental drivers of the intraday and day-ahead price differences in the two Danish bidding zones can be found in the results of the *Price_dif* equations. One immediate conclusion to be drawn is that both wind and conventional power forecast errors significantly

cause the intraday prices to deviate from the day-ahead values in both DK1 and DK2. This result implies that the deviations of intraday prices from the day-ahead values are supply-side driven, and that the production forecast errors (both wind and CHP) are to some extent digested in the intraday settings.

Besides the above-mentioned similarities, there are also some significant and notable differences with respect to causal relationships. In DK1, the demand side has also a significant role in electricity price deviations in the intraday market, while in DK2 the cross-border exchange flows additionally cause the intraday prices to diverge from their day-ahead values. Reciprocally, these price deviations in turn affect both the load deviations in DK1 and the net electricity flows in DK2. Furthermore, consumption forecast errors seem to be corrected via cross-border electricity transmission in DK2, which, once again, does not occur in DK1. On the one hand, the significant influence from the demand side in DK1 can be explained by a size effect, which means that the scale of power consumption in DK1 is much larger than that in DK2. For instance in 2013, electricity consumption in DK1 is on average 46% higher than that in DK2. This may induce larger load forecast errors and error variances in DK1, which may have a greater impact on the intraday market. DK1 has also a higher intraday trade share, and thus consumption “shocks” may be more influential on the price deviations. On the other hand, Nord Pool Spot’s Elbas is generally the single marketplace for the intraday trading on the most of the interconnections between the Danish bidding zones and other coupling partners. One exception is given to the border between Denmark West and Germany, on which physical transmission rights are issued through monthly and yearly auctions via a capacity platform (DERA, 2015).¹⁵ Therefore, the physical use of a long-term capacity sale on the border of DK1 and Germany may weaken the causal link between short-term intraday trading and cross-border exchanges in Western Denmark.

Concerning the uncertainty of wind power generation, our results offer a striking point that wind forecast errors not only drive intraday prices away from their day-ahead values, but also affect significantly CHP and load forecast errors, and intraday cross-border trade. Recall that the production forecast errors are calculated as the difference between the realized production and its forecasted level, so that these deviations from the day-ahead forecasts may also include the responses in real-time balancing markets. Therefore, the inevitable problem of wind generation’s intermittency is tackled through the Elbas intraday trading, and also plausibly through the balancing mechanism. The above arguments altogether with the

¹⁵The allocation of available transfer capacity on the border of Denmark West and Germany can be found at the website of IntradayCapacity.

persistence of responses will be further discussed in the next section.

4.6 Discussions

With the causality results in mind, a further analysis of the dynamic interrelationships between the variables involved in the VAR system can be carried out by studying the impulse response outputs of the model, which are depicted in Figs. 4.9 and 4.10. More specifically, these figures outline the paths of the price responses after one standard deviation shock from the market fundamentals (Fig. 4.9), and the responses of quantity variables resulted from a shock in wind forecast errors (Fig. 4.10) during the following 24 hours.

The inferences that we can draw from the GIR functions are quite parallel to the above-obtained causality results.¹⁶ Let us consider first Fig. 4.9, and discuss the main drivers of the intraday price divergences in DK1 and DK2, whose paths depict the way of functioning of the Nord Pool intraday market. As seen in Fig. 4.9, wind forecast errors have a significantly negative impact on deviations between intraday and day-ahead electricity prices in both DK1 and DK2. That is to say, wind producers are indeed actively involved in intraday trading, so that the negative causality between the intraday-day-ahead divergences and the wind forecast errors indicates that wind generators are willing to pay high when deviation shocks in production are negative, and to sell low when they are positive. In contrast, the impact on price responses turns out to be positive when we consider CHP errors. Although the Nordic intraday market conducts bilateral trading as a market rule, the merit order still matters at the margin. Considering the fact that the marginal cost of CHP generation is certainly higher than the nearly zero variable cost of wind generation, an unexpected increase in CHP generation requires a higher intraday price relative to the price level in the day-ahead market. Besides, a CHP plant must run at least a minimum of a few hours in order to effectively lower start-up costs, which should also be reflected in the intraday prices when CHP generators trade close to real time. Many works have been dedicated to the measure of the merit order effect in day-ahead electricity markets (e.g. Jónsson et al., 2010; Ketterer, 2014; Traber and Kemfert, 2011), but here, our results reveal clear evidence that this effect of reduction in prices resulted from wind generation exists not only in day-ahead but also in intraday market.

¹⁶Note that in DK2 the transmission from the innovations in Load_er to Price_dif is not significant. However, in DK1, although the initial response of Price_dif to an innovation in Flow is marginally statistically significant, it quickly fades away after the first hour. This implies that Flow and Load_er do not exert a causal effect on Price_dif in DK1 and DK2, respectively.

Additionally, in DK1, the bidirectional causality found between price deviations and load forecast errors tends to be positive, while in DK2 this causal relationship cannot be seen as a significant one. Before we discuss the results in Fig. 4.10, let us illustrate this point also from a static perspective. The two scatter plots shown in Fig. 4.11 indicate a slight positive correlation between intraday price deviations and consumption forecast errors in DK1, but no significant correlation between the same variables in DK2. Furthermore, instantaneous negative responses between price deviations and intraday exchange flows are prevailing.¹⁷ In terms of the persistence of the impact of wind deviations on the intraday market, the departed price signals tend to fade away after 12 hours in DK1 and DK2, implying that one shock in wind generation deviations at a given hour is followed by generators' continuous adjustments according to their improved prognoses on real wind generation for the succeeding hours, and thus, the intraday adjustment resulted from the shock does not disappear quickly. All in all, our examination of intraday price signals relative to day-ahead price levels proves the rectitude of the market design of the intraday market, and it is especially meaningful for intermittent generation.

We now turn to Fig. 4.10 that shows how the Danish intermittent generation is interacted with other market elements. More precisely, we analyze the response functions of CHP and load forecast errors, and intraday exchange flows to the impulses of wind forecast errors, in order to backtrack how imbalances caused by wind variability are dissolved in the system. A comparison between DK1 and DK2 in Fig. 4.10 shows that their diagrams in these two zones are quite consistent. The response patterns of the trade variable clearly show that wind forecast errors affect negatively the cross-border exchanges in the intraday market, which are measured by net inflows to the Danish bidding zones. More precisely, negative shocks to wind output in Denmark tend to stimulate power imports in the intraday market. Notice that this impact is significant during the upcoming 12 hours, which reasonably concurs with the persistence of intraday price deviations. As a consequence, the causality running from wind deviations to both net exchange flows and intraday price deviations demonstrates that international connections provide a critical support to the Danish intraday trading when having a large scale of wind power fed in the system, and that they are especially advantageous as the Danish neighboring countries' possess abundant hydro power resources. Accordingly, as noted in Section 4.4.2, the formation of the Danish intraday prices does not generally reflect resource

¹⁷The GIR of Load_er_DK1 to Price_dif_DK1 is similar to that of Price_dif_DK1 to Load_er_DK1. The GIR of Flow_DK2 to Price_dif_DK2 is similar to that of Price_dif_DK2 to Flow_DK2. They are not presented in this section, but in Fig. B.1 in Appendix B.

scarcities since Denmark's interactions with neighboring hydro reserves through imports and exports are capable to smooth the variations in the price series. In support of this view, our empirical evidence suggests that wind forecast errors are strictly damped out in the intraday mechanism, because their causal influences on both price differences and cross-border trading are found.

Concerning the responses from the supply and demand sides, wind forecast errors exert a negative (positive) influence on conventional (load) forecast errors. That is to say, in order to keep the system balanced, the CHP power generation is adjusted in the opposite direction, and the consumption is adjusted in the same direction of the deviation shocks in wind power. It is worth mentioning again that the conventional generation can play a counterpart to the wind generation, either through intraday trading or real-time balancing, as both traded quantities are incorporated in the deviation terms. Nevertheless, given the fact that balancing quantities in Denmark are relatively small, and that CHP BRPs would pay penalties on their imbalances at the balancing stage, it is fair to say that the intraday market takes a major part in trading CHP generation deviations. Furthermore, the patterns of the reactions from consumption and conventional generation appear to be non-uniform in DK1 and DK2. In the former zone, an immediate response from demand seems to vanish fast, and the response from conventional production proceeds much more smoothly, whereas in the latter zone, it seems to be the opposite case. Given the complexity of electricity trading in sequential markets, providing explanations underneath these findings may be a hard row to hoe. Although untangling different demand and supply patterns in these two bidding zones is not straightforward, it is nonetheless important to emphasize the notable reactions from primary CHP generation and load, through which the intermittent nature of wind power is effectively handled.

4.7 Conclusion

Intraday electricity markets are designed to provide a useful mechanism to allow electricity generators and consumers to adjust their day-ahead committed quantities according to improved forecasts. It has been argued that these markets are particularly important for the wind power generators given the fact that wind power is intermittent and poorly predictable. Despite its growing importance, particularly for the integration of wind power into the electricity system, the role and functionality of intraday markets has been overlooked in research in this field.

As the first attempt to test the functionality of an intraday market in a dynamic econo-

metric framework, this chapter investigated: first, the fundamental drivers of the deviations of the intraday prices from the day-ahead values with particular attention to wind forecast errors; second, the way in which wind forecast errors are dissolved by other market elements. In order to undertake this investigation, our innovative idea is to test causality among intraday market fundamentals by applying a methodology that consists of a VAR framework and GIR simulations. Using data from two Danish bidding zones, this chapter studied the causal relationships among the price differences between the intraday and day-ahead markets, the deviations of wind generation, conventional generation, and total demand from their committed day-ahead levels as well as the cross-border electricity trades in the Nordic electricity market. Compared with earlier econometric studies in the field of energy economics, this study provides the first evidence not only on the effectiveness of the intraday electricity market, but also on the way in which the prices in this market are affected by wind power that deviates from its prognosis. The VAR and GIR techniques employed in this study have offered straightforward explanations on both the paths of intraday price deviations, and the interactions among market fundamentals. Thus, the results are able to give a reliable answer to the fundamental hypothesis tested in the framework of this research: the Nordic intraday electricity market can be regarded as effective if causality between the intraday price signals and the market fundamentals can be established.

Our empirical results suggest that the wind and conventional generation forecast errors are the fundamental factors that drive the intraday prices apart from the day-ahead values both in Denmark West and East, and that the relative intraday prices decrease with the level of wind forecast errors. Furthermore, wind forecast errors are absorbed by joint responses from cross-border intraday power exchanges and adjustments of conventional generation and consumption. The results also indicate some zonal differences concerning causality from wind forecast errors to price differences, and the response paths of market fundamentals. Finally, the responses in the intraday price signals and electricity trade following a shock in wind generation die out after 12 hours in the intraday market.

The bottom line is that this work confirms the effective functioning of the intraday market in the case of Denmark, in which intermittent production deviations are explicitly reduced by intraday transactions, and in addition, wind forecast errors are jointly handled through the responses from consumption, conventional generation, and intraday cross-border trade.

Eventually, it is nonetheless important to notice that two caveats should be put forward. First, our analyses give evidence on the practicality of an intraday market, but do not lead us to conclude on its optimality. It has been argued that in an efficient market setting,

adjustments from both supply and demand sides should be made to the largest extent in intraday markets given higher costs of balancing in real time. But in the Nordic region, these costs may not be significant due to a high level of hydro reserves. The examination of the overall system efficiency requires comprehensive cost and price comparisons between intraday trading and real-time balancing that relies on transmission capacities. Second, the assumption of exogenous wind forecast errors might not be entirely met in some cases, as wind producers can possibly overstate or understate their productions. This consideration is clearly beyond the scope of this study, but a relevant work appears to be an investigation on wind generators' strategic behaviors. These questions are therefore left open for future research.



Figure 4.9 – Responses of the difference between day-ahead and intraday prices to generalized one standard deviation innovations in quantity variables in DK1 and DK2. *Notes:* The forecast horizon ($h = 1, 2, \dots, 24$ hours) is displayed on the horizontal axis. The vertical axis measures the magnitude of the response to the impulse. The responses represent deviations in €/MWh from the steady state of the variable Price_dif, and the impulses are scaled such that 1 equals one standard deviation in the variables Wind_er, CHP_er, Load_er, and Flow. The blue lines plot the point estimates for the impulse responses, and the red lines show 95% confidence bands with ± 2 standard errors.

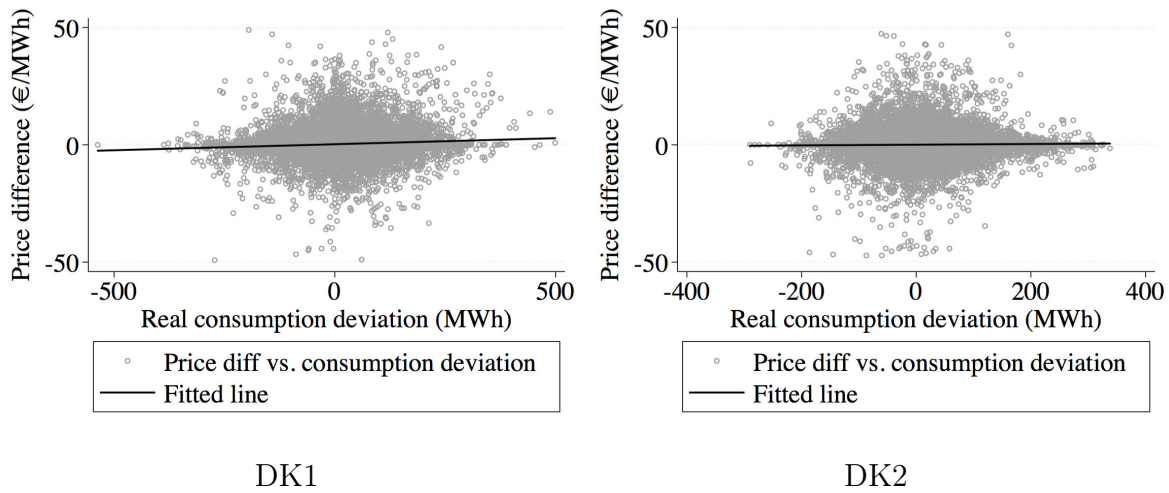


Figure 4.11 – Price differences versus consumption deviations in DK1 and DK2. Data source: Authors' realization based on Nord Pool Spot (2014).

Bibliography

- [1] Aatola, P., Ollikainen, M., Toppinen, A., 2013. Price determination in the EU ETS market: Theory and econometric analysis with market fundamentals. *Energy Economics*, 36, 380-395.
- [2] Borenstein, S., 2012. The Private and Public Economics of Renewable Electricity Generation. *The Journal of Economic Perspectives*, 26(1), 67-92.
- [3] Borggrefe, F., Neuhoff, K., 2011. Balancing and intraday market design: Options for wind integration. No. 1162. Discussion Papers, German Institute for Economic Research, DIW Berlin.
- [4] Bourry, F., Kariniotakis, G., 2009. Strategies for wind power trading in sequential short-term electricity markets. *In Proceedings European Wind Energy Conference and Exhibition*.
- [5] Chaves-Ávila, J. P., Hakvoort, R. A., Ramos, A. 2013. Short-term strategies for Dutch wind power producers to reduce imbalance costs. *Energy Policy*, 52, 573-582.
- [6] Danish Energy Agency DEA 2015. Facts about Wind Power, Copenhagen.
- [7] Danish Energy Regulatory Authority DERA 2015. *2014 National Report to the European Commission Denmark*.
- [8] Danish Wind Industry Association 2014. The Danish Market: Statistics on the development of wind power in Denmark 2003-2013.
- [9] Dickey, D. A., Fuller, W. A., 1979. Distribution of the Estimators for Autoregressive Time Series with a Unit Root. *Journal of the American Statistical Association*, 74, 427-431.

- [10] Elliott, G., Rothenberg, T.J., Stock, J.H., 1996. Efficient tests for an autoregressive unit root. *Econometrica*, 64, 813-836.
- [11] Energinet.dk 2008. Regulation C2: The balancing market and balance settlement, Copenhagen.
- [12] Energinet.dk 2011. Regulation C1: Terms of balance responsibility, Copenhagen.
- [13] Energinet.dk 2014. Download of market data.
- [14] Fabbri, A., Román, T. G. S., Abbad, J. R., Quezada, V. H. M., 2005. Assessment of the cost associated with wind generation prediction errors in a liberalized electricity market. *IEEE Transactions on Power Systems*, 203, 1440-1446.
- [15] Furió, D., Lucia, J. J., Meneu, V., 2009. The Spanish Electricity Intraday Market: Prices and Liquidity Risk. *Current Politics and Economics of Europe*, 20, 1-22.
- [16] Granger, C. W. J., 1969. Investigating causal relations by econometric models and cross-spectral methods. *Econometrica*, 37, 424-438.
- [17] Green, R., Vasilakos, N., 2012. Storing Wind for a Rainy Day: What kind of electricity does Denmark export?. *The Energy Journal*, 33(3), 1-22.
- [18] Hagemann, S., 2013. Price Determinants in the German Intraday Market for Electricity: An Empirical Analysis. No. 1318. University of Duisburg-Essen, Chair for Management Science and Energy Economics.
- [19] Hagemann, S., Weber, C., 2013. An Empirical Analysis of Liquidity and its Determinants in The German Intraday Market for Electricity. No. 1317. University of Duisburg-Essen, Chair for Management Science and Energy Economics.
- [20] Henriot, A., 2014. Market design with centralized wind power management: handling low-predictability in intraday markets. *The Energy Journal*, 35(1), 99-117.
- [21] Hiroux, C., Saguan, M., 2010. Large-scale wind power in European electricity markets: Time for revisiting support schemes and market designs?. *Energy Policy*, 38, 3135-3145.
- [22] Hirth, L., Ueckerdt, F., Edenhofer, O. 2015. Integration costs revisited – An economic framework for wind and solar variability. *Renewable Energy*, 74, 925-939.

- [23] Holttinen, H., 2005. Optimal electricity market for wind power. *Energy Policy*, 33(16), 2052-2063.
- [24] Ito, K., Reguant, M., 2014. Blowin' in the Wind: Sequential Markets, Market Power and Arbitrage.
- [25] Jónsson, T., Pinson, P., Madsen, H., 2010. On the market impact of wind energy forecasts. *Energy Economics*, 32, 313-320.
- [26] Joskow, P. L., 2011. Comparing the costs of intermittent and dispatchable electricity generating technologies. *The American Economic Review*, 238-241.
- [27] Ketterer, J. C., 2014. The impact of wind power generation on the electricity price in Germany. *Energy Economics* 44, 270-280.
- [28] Koop, G., Pesaran, M.H., Potter, S.M., 1996. Impulse response analysis in nonlinear multivariate models. *Journal of Econometrics*, 74, 119-147.
- [29] Mauritzen, J., 2015. Now or Later? Trading wind power closer to real-time and how poorly designed subsidies lead to higher balancing costs. *The Energy Journal*, 36(4).
- [30] Ng, S., Perron, P., 2001. Lag length selection and the construction of unit root tests with good size and power. *Econometrica*, 69, 1519-1554.
- [31] Nord Pool Spot 2014. Download centre.
- [32] Nord Pool Spot 2015. Intraday market: How does it work.
- [33] Pesaran, M.H., Shin, Y., 1998. Generalized impulse response analysis in linear multivariate models. *Economics Letters*, 58, 17-29.
- [34] Pereira, J. P., Rodrigues, P. M., 2015. The impact of wind generation on the mean and volatility of electricity prices in Portugal.
- [35] Phillips, P.C.B., Perron, P., 1988. Testing for a Unit Root in Time Series Regression. *Biometrika*, 75, 335-346.
- [36] Rintamäki, T., Siddiqui, A., Salo, A., 2014. Does renewable energy generation decrease the volatility of electricity prices? a comparative analysis of Denmark and Germany, tech. rep., Working paper, Systems Analysis Laboratory, Aalto University.

- [37] Said, S.E., Dickey, D.A., 1984. Testing for Unit Roots in Autoregressive-Moving Average Models of Unknown Order. *Biometrika*, 71, 599-607.
- [38] Smeers, Y., 2008. Study on the general design of electricity market mechanisms close to real time. Commissioned by: The Commission for electricity and Gas Regulation CREG.
- [39] Stefano, C., Alessandra, C., Pietro, Z., 2015. The merit-order effect in the Italian power market: The impact of solar and wind generation on national wholesale electricity prices. *Energy Policy*, 77, 79-88.
- [40] Traber, T., Kemfert, C., 2011. Gone with the wind? – Electricity market prices and incentives to invest in thermal power plants under increasing wind energy supply. *Energy Economics*, 33, 249-256.
- [41] Von Selsinsky, A., 2014. The Integration of Renewables in Continuous Intraday Markets for Electricity. Available at SSRN 2405454.
- [42] Weber, C., 2010. Adequate intraday market design to enable the integration of wind energy into the European power systems. *Energy Policy*, 38(7), 3155-3163.

Appendices

Appendix A. Summary statistics of the variables

Table A.1: Summary statistics for DK1

| Variable | Avg. | S.D. | Med. | Max. | Min. | Skew. | Kurt. | ADF | Nb. positive | Nb. negative | Nb. zero |
|------------|--------|--------|--------|---------|----------|-------|--------|--------|-----------------|-----------------|-------------|
| CHP error | 374.22 | 712.89 | 198.65 | 3171.40 | -2082.50 | 0.77 | 3.17 | -17.79 | 13574 | 7592 | 2 |
| Con. Error | 15.46 | 81.82 | 7.00 | 1952.00 | -537.00 | 0.83 | 20.19 | -15.71 | 12113 | 8712 | 343 |
| Elbas flow | -12.40 | 93.38 | 0.00 | 890.60 | -1149.50 | -0.32 | 16.79 | -18.50 | 6235 | 9009 | 5924 |
| Price dif | 0.38 | 6.69 | 0.00 | 232.38 | -88.63 | 8.53 | 260.54 | -18.57 | 8293 | 7980 | 4895 |

Summary statistics of the average, standard deviation, median, maximum, minimum, skewness, kurtosis and numbers of observations with positive, negative and zero values for each variable.

Table A.2: Summary statistics for DK2

| Variable | Avg. | S.D. | Med. | Max. | Min. | Skew. | Kurt. | ADF | Nb. positive | Nb. negative | Nb. zero |
|------------|--------|--------|--------|---------|----------|-------|--------|--------|-----------------|-----------------|-------------|
| CHP error | -62.42 | 159.73 | -63.40 | 868.60 | -1101.50 | -0.06 | 3.90 | -16.38 | 6892 | 14270 | 6 |
| Con. Error | 11.67 | 69.22 | 4.00 | 338.00 | -1930.00 | -0.61 | 33.51 | -17.88 | 11319 | 9578 | 271 |
| Elbas flow | 10.24 | 59.79 | 0.00 | 1216.00 | -336.00 | 2.50 | 30.55 | -19.28 | 7238 | 5875 | 8055 |
| Price dif | 0.10 | 5.85 | 0.00 | 210.00 | -109.38 | 2.96 | 117.55 | -20.02 | 6610 | 6712 | 7846 |

Summary statistics of the average, standard deviation, median, maximum, minimum, skewness, kurtosis and numbers of observations with positive, negative and zero values for each variable.

Appendix B. Impulse response functions

Appendix C. Alternative causality tests: Sims (1973) and Geweke (1982)

Again discussed in Chapter 1, causality tests conducted in a VAR framework are adequate for identifications, but an application of Sims and Geweke causality tests may give us some insight into the exogeneity of wind forecast errors and instantaneous feedbacks between price differences and wind forecast errors, although these two tests do not involve a system of equations. The results are reported in Table C.1. According to the results of Sims causality, as we expected, we cannot rule out that price differences are endogenous to wind forecasts

errors because the coefficients of the future values of this variable are jointly significantly different from zero. In the contrary, we may suspect that wind forecast errors in DK1 are not exogenous, as implied in our previous assumption. This point further gives a motivation to investigate strategic behavior of wind generators, as we suggested to do so in the conclusion section. Additionally, according to the result of Geweke causality, there is again a difference between DK1 and DK2. The instantaneous feedback between wind forecast errors and price differences are found to be significant in DK1. However, its share is small in both regions, because the share of Granger influence is very high in both regions. Therefore, Granger causality takes the major part in the determination of the relationships between wind forecast errors and intraday price deviations.

Table C.1: Results of Sims and Geweke causality

| | Sims causality | | Geweke causality | | |
|-----|---------------------------------------------|---------------------------------------------|---------------------------|----------------------|------------------------|
| | <i>Wind_er</i> future → <i>Price_dif</i> | <i>Price_dif</i> future → <i>Wind_er</i> | Instantaneous feedback | Total correlation | % Granger causality |
| DK1 | 4.47** | 8.36** | 25.15** | 153.67** | 83.63% |
| DK2 | 1.07 | 5.43** | 2.3 | 77.55** | 97.03% |

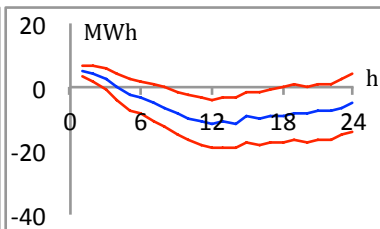
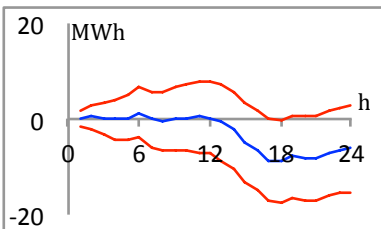
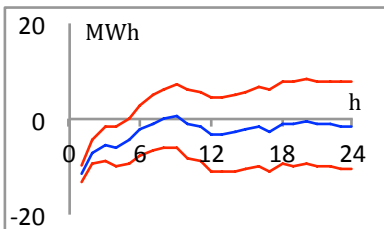
χ^2 -statistics are given for the null hypothesis that all coefficients of the variables' future values are jointly zero. * and ** denote the rejection of the null hypothesis of non causality at the 5% and 1% respectively. The Sims test is conducted by an OLS regression with 24 lags and leads.

Responses of CHP_er_DK1

to Flow_DK1

to Load_er_DK1

to Price_dif_DK1

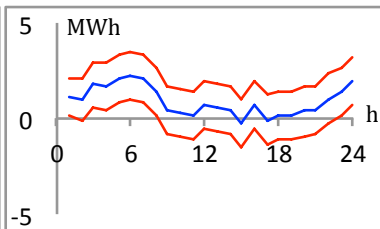
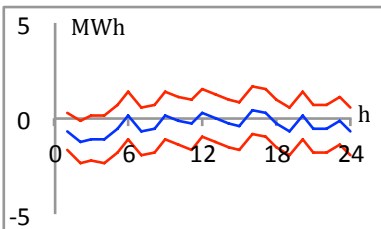
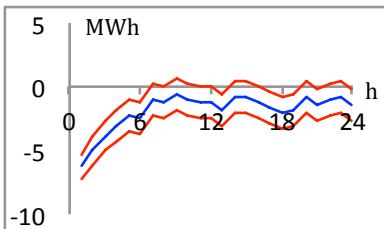


Responses of Flow_DK1

to CHP_er_DK1

to Load_er_DK1

to Price_dif_DK1

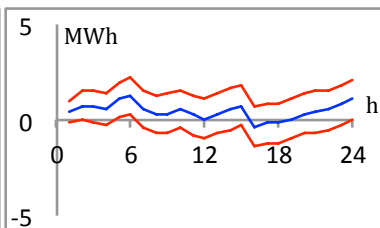
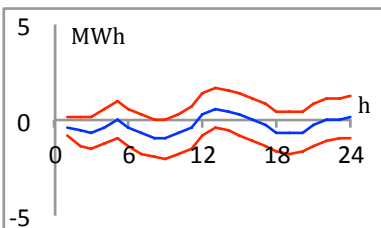
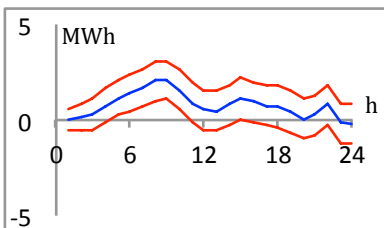


Responses of Load_er_DK1

to CHP_er_DK1

to Flow_DK1

to Price_dif_DK1

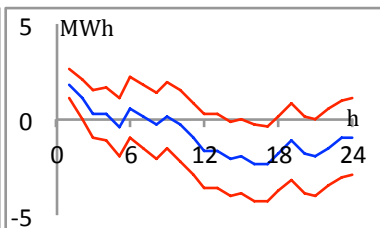
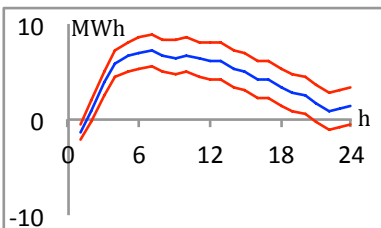
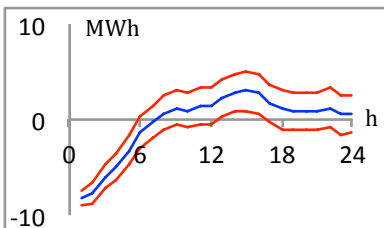


Responses of CHP_er_DK2

to Flow_DK2

to Load_er_DK2

to Price_dif_DK2

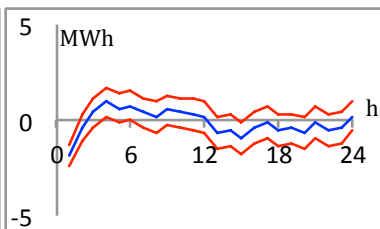
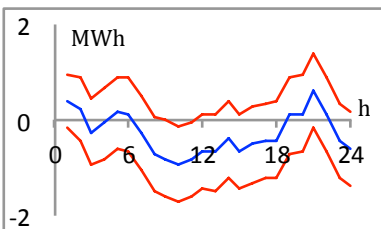
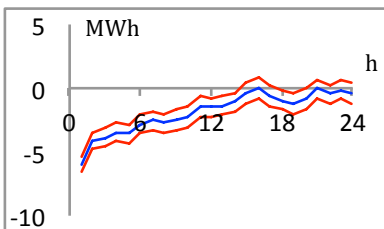


Responses of Flow_DK2

to CHP_er_DK2

to Load_er_DK2

to Price_dif_DK2



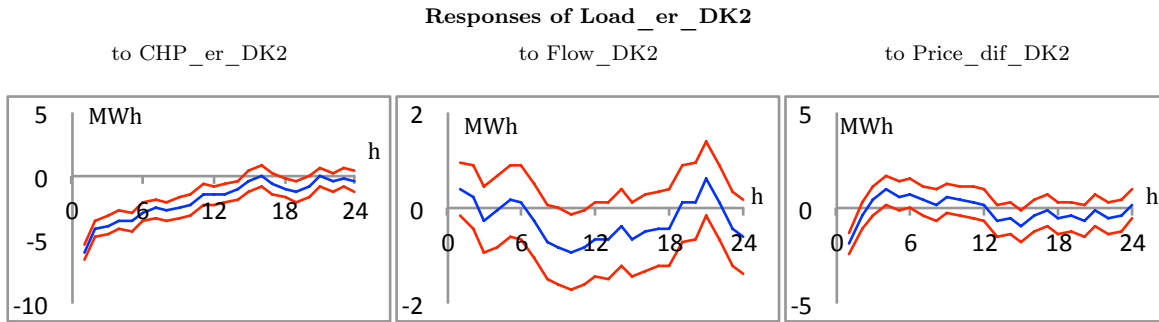


Fig. B.1: Responses in DK1 and DK2 to generalized one standard deviation innovations. *Notes:* See Figs. 4.9 and 4.10 for explanations.

Chapter 5

Conclusion générale

*

L'objectif de cette thèse est d'étudier les nouvelles dynamiques et leurs impacts dans le secteur de l'électricité. Elle discute des sujets critiques d'après les perspectives de la macroéconomie, de la configuration structurelle, et de la transition vers des sources d'énergie renouvelables. En mettant en jeu ces trois perspectives, elle tente d'apporter des réponses aux défis principaux de la sécurité d'approvisionnement, de la compétitivité, et de la durabilité du développement énergétique. En donnant de nouvelles orientations dans la recherche sur l'économie de l'énergie, elle servira à éclairer le débat politique sur le sujet.

Avant de tourner notre attention vers les marchés de l'électricité, le premier chapitre de cette thèse souligne que les priorités des politiques de l'énergie reflètent les besoins les plus urgents des pays. Par conséquent, l'élaboration de la politique énergétique et ses influences sur la croissance économique dans les pays développés et dans les pays en voie de développement ne peuvent être considérés de la même manière. Connaître les différences dans les liens de causalité entre la demande de l'électricité et le développement économique sert comme une première étape avant d'entreprendre des réformes de marché. Pour ce faire, il faut tenir suffisamment compte des facteurs importants selon les pays : l'ouverture institutionnelle, les disparités des revenus, le progrès urbain, le degré d'intégration du marché, les contraintes de localisation, et la vulnérabilité de l'approvisionnement externe. Ce chapitre relève que l'urbanisation ou les importations et exportations de l'électricité sont des facteurs importants pour déterminer le niveau de la consommation dans les pays sous-développés ou en voie de développement, car ils ont souvent un niveau de consommation électrique limité soit par la disponibilité de l'accès à l'électricité soit par l'intégration insuffisante du marché. Surtout, en Afrique sub-saharienne et en Asie du Sud, la priorité énergétique devrait être donnée à une expansion du réseau afin d'assurer une couverture complète de l'approvisionnement en électricité. Les politiques énergétiques dans les pays émergents comme la Chine devraient également orienter vers la sécurité d'approvisionnement, car leur urbanisation rapide est forcément accompagnée par une croissance significative de la demande d'électricité. En fait, l'élaboration de la politique de l'énergie peut être faite d'une manière plus indépendante de la trajectoire économique des pays, qui ont déjà atteint un niveau élevé de revenu, une grande population urbaine, et une intégration avancée des marchés. Sinon, les impacts des politiques concernant les marchés de l'énergie sur la croissance économique ne peuvent assurément être ignorés.

D'un point vu concurrentiel, le deuxième chapitre s'intéresse à la structure d'un marché de gros de l'électricité et à la relation verticale entre ses participants. La littérature précédente a mis en évidence que les contrats à terme peuvent atténuer le pouvoir de marché des producteurs dans un marché de l'électricité. Toutefois, cet argument ne peut être confirmé sans examiner

la structure du marché. Le chapitre 2 fournit un fondement théorique pour étudier l'impact de l'intégration verticale entre un producteur et un détaillant sur le commerce de contrats à terme et sur la concurrence dans un marché de gros de l'électricité. Il met l'accent sur à la fois la particularité du marché de gros de l'électricité, et les différents impacts de l'intégration verticale et des contrats à terme sur la concurrence. Il fournit une base théorique de l'examen des fusions verticale dans le secteur électrique pour la politique de la concurrence. Il montre les conditions sous lesquelles une intégration verticale entre un producteur et un détaillant peut être anti-concurrentielle, et les raisons sous-jacentes à cet effet négatif. Ces dernières sont : (1) comme instrument de couverture structurelle, l'intégration verticale est utilisée par le détaillant intégré à la place des contrats à terme; (2) la dépendance des bénéfices sur les actifs de production donne une incitation plus élevée au détaillant intégré d'augmenter le prix au comptant. Par conséquent, cet effet anti-concurrentiel potentiel devrait préoccuper les autorités de la concurrence.

Face aux défis importants liés aux énergies renouvelables intermittentes, l'ensemble du troisième et quatrième chapitre cherche à étudier à la fois les conséquences d'une part croissante de la production éolienne sur le marché de gros, et le fonctionnement d'un marché intrajournalier pour résoudre les déséquilibres du système induits par l'incertitude de l'intermittence. Ces deux répercussions sur les marchés électriques sont causées fondamentalement par deux caractéristiques particulières de la production éolienne. D'un côté, sa variabilité et sa non-contrôlabilité apportent des fluctuations continues aux prix day-ahead. De l'autre côté, sa mauvaise prévisibilité impose une énorme pression sur le système pour résoudre les déséquilibres à un coût raisonnable. L'expérience du Danemark et du marché Nordique nous montre que les fluctuations et les incertitudes de l'énergie éolienne peuvent être gérées par d'une part une substitution entre la production éolienne et la production hydraulique, et d'autre part des réseaux extensifs internationaux. Sur le marché day-ahead, ces deux spécificités dans les pays Nordiques rendent les signaux de prix relativement stables. Sur le marché intraday, l'incertitude intermittente de la production est effectivement réduite par les transactions intra-journalières, et les erreurs de prévision de la production éolienne sont traitées conjointement par les réponses de la demande, de la production conventionnelle et des transactions internationales intra-journalières.

En somme, pour s'adapter à la nécessité d'un approvisionnement efficace et durable de l'électricité, les politiques et les modèles de marché sont toujours en cours de révolution. Un changement important dans le secteur de l'énergie de 2014 à 2015 a été la chute de prix du pétrole, du gaz naturel et du charbon dans le monde (AIE, 2015). Les faibles prix des com-

bustibles fossiles sont susceptibles de devenir un stimulus à la croissance économique (FMI, 2015) mais une menace pour le développement des énergies renouvelables. En 2015, la Commission européenne a présenté de nouvelles stratégies avec un objectif climatique prospectif pour redessiner le marché européen de l'électricité et pour promouvoir les économies d'énergie. Dans cette nouvelle proposition, elle préconise clairement, entre d'autres, une approche plus coordonnée de soutien aux renouvelables dans les états membres et un régime de marché suffisamment souple pour permettre des négociations proche du temps réel (CE, 2015). Dans ce contexte, il est clair que le développement futur du marché de l'électricité sera entraîné par la transition vers les technologies à faible émission de carbone, et que l'élaboration des politiques dans les marchés de l'énergie sera fusionnée avec celle de la politique climatique. Cette tendance a avancé la nécessité d'une unification des cadres politiques différents, car ceux-ci présentent actuellement plusieurs conflits d'intérêt, en termes de macroéconomie, de concurrence et d'efficacité du marché, et de supports aux énergies renouvelables. Outre une harmonisation des cadres de politiques, il est aussi important de reconnaître les disparités entre les stades de développement économique des pays, de sorte que la question la plus importante à aborder dans le secteur de l'électricité n'est clairement pas la même dans de différents pays. Cela signifie que les efforts sur les réformes d'un pays ne peuvent dépasser le niveau que ses conditions économiques peuvent permettre. En outre, l'amélioration de l'intégration du marché peut réduire la dépendance énergétique, intensifier la concurrence et assurer la sécurité d'approvisionnement. Enfin, pour pouvoir réduire l'incertitude de la production intermittente, il y a un besoin à la fois de mettre en place un mécanisme d'échange avec un délai plus court et de développer d'une manière efficace les technologies de production à substituer à la baisse de la production des énergies renouvelables à cause de leur intermittence.

Même si cette thèse ne résout qu'une partie du problème compliqué posé au secteur de l'électricité, elle cherche à attirer l'attention sur les différentes problématiques, et de plus à mettre en lumière les orientations de la recherche future. Beaucoup de sujets demandent à être approfondis et de nouvelles questions de recherche attendent d'être explorées. Par exemple, comment la distribution spatiale de la production d'énergie renouvelable au niveau de l'usine influe la variance de la production et la stabilité du système, et comment les technologies de stockage de l'électricité, qui vont fondamentalement changer ses caractéristiques physiques et ses contraintes, affectent l'organisation et la compétitivité du marché ?

Bibliography

- [1] European Commission (EC), 2015. *Transforming Europe's energy system - Commission's energy summer package leads the way*, Brussels.
- [2] International Energy Agency (IEA), 2015. *Energy and Climate Change - World Energy Outlook Special Report*, Paris.
- [3] International Monetary Fund (IMF), 2015. *World Economic Outlook*, Washington, DC.