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Policy coordination and zonal configurations

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Abstract

Swiss electricity markets are subject to several large-scale changes. Market power is to be reduced with the second phase of market liberalization and renewables are intended to replace nuclear power. In the course of these changes, the current market design will likely have to be adjusted necessitating an adaptation of existing or an introduction of new policy measures and regulatory interventions. In this context, this project explores how political interventions in electricity markets interact and if they need to be coordinated. For this analysis, we develop a conceptual electricity market model including supply and demand representing an imperfectly liberalized market with consumers that are hesitant to switch suppliers. Our results show that demand- and supply-side problems are almost perfectly decoupled. Hence, policy should aim for coordinating interventions on the demand side (such as measures to incentivize supplier switching and the structure of grid tariffs) and, separately, coordinating interventions on the supply side (such as feed-in premiums or tariffs and capacity markets). Focusing on supply side policies, this project further investigates the role of potential policy approaches to support investments (capacity market, feed-in premiums, and a quota mechanism) and the Swiss network structure on investment incentives. Our results show that a zonal reconfiguration of the Swiss electricity market into a Northern and Southern zone does only require coordination with policy targets if such a split is also linked to zonal targets for generation capacities. However, the policy design needs to take into account the potential for strategic company behavior to avoid exploitation and suboptimal investments.

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List of abbreviations

CTI	Swiss Commission for Technology and Innovation
EWG	Energy - Economy - Society Research Programme / Forschungsprogramm Energie - Wirtschaft - Gesellschaft
PSI	Paul Scherrer Institute
SCCER CREST	(Swiss Competence Center for Energy Research, Competence Center for Research in Energy, Society and Transition
SFOE	Swiss Federal Office of Energy (Schweizerisches Bundesamt für Energie)
WWZ	Faculty of Business and Economics at the University of Basel (Wirtschaftswissenschaftliche Fakultät der Universität Basel)

Executive Summary

Swiss electricity markets are subject to major changes in the future related to a significant transformation of today's supply infrastructure where nuclear power is to be replaced by renewable energy sources. Additionally, the second stage of market liberalization that also includes small consumers is planned. Further, European market developments will continue to strongly influence the Swiss electricity market. In the course of these changes the current market design might require an adaptation of existing or an introduction of new policy measures. In this context, this project investigates three related topics.

Firstly, it analytically explores how political interventions in electricity markets interact and if they need to be coordinated, and whether an imperfectly competitive retail market induces problems on the supply side. Second, we aim to quantify the impact of different policy and market design adjustments on the Swiss market. Finally, we extend the quantitative analysis by focusing on the role of regionally differentiated market and policy structures. The first part of the project yields insights into the pathways in which the effects of these political interventions are interrelated and provides options for coordinating the instruments. Furthermore, the outcome of this first project part directs the investigations in the subsequent numerical analysis.

For our conceptual analysis of policy interactions, we develop a conceptual electricity market model. The model's demand side represents imperfect market liberalization[1] due to an imperfectly competitive retail market where consumers hesitate to switch providers and where grid tariffs amplify this effect. We couple this demand-side model with a production model, where suppliers can invest into two different technologies, one with random production characteristics (intermittent renewables) and one being a controllable technology (e.g. hydropower), and where producers can trade on an (also imperfectly competitive) spot market. The model further includes a set of different policy interventions on the supply and demand side.

Our results show that, in a liberalized market, demand- and supply-side problems are almost perfectly decoupled, even though firms retain some market power both on the retail and on the spot market. Hence, under the assumptions taken, policy should aim for coordinating interventions on the demand side (such as support for consumer switching and grid tariffs) and, separately, coordinating interventions on the supply side (such as feed-in premiums or tariffs and capacity markets). This conclusion (only) relates to the situation of an imperfectly

[1] In this project, imperfect market liberalization describes the situation found in many liberalized electricity markets, where consumers can in principle choose their supplier but many customers do not switch suppliers (even though it would pay off) due to market frictions or other barriers.

liberalized market but does not relate to a switch from the current regional monopoly with cost-based retail prices to a liberalized market framework with competition. In a regulated market, each retailer can charge its cost level to end consumers, which can be above or below the wholesale price level depending on the cost structure of the retailers' generation portfolio. In contrast, in a liberalized market, the wholesale price will drive production decisions for all retailers and will be an important basis for setting retail prices. [2]

Further, the well-known hesitancy of consumers to switch suppliers allows the providers to exert market power on the retail market (i.e. via markups on the wholesale price level), resulting in price differences where firms with larger home markets set higher prices in comparison to the smaller competitors. Given the existence of market power on the retail market, access to a sufficiently large spot market such as the European electricity market is of central importance to support an optimal allocation of investments into production facilities amongst the different suppliers and thereby reduce the need for the coordination of political interventions.

Our results also show that, in particular on the supply side, a substantial coordination of policies is called for. If intermittent renewables are to be promoted (which is the case in most industrialised countries) and a certain predefined level of domestic production capacity is also desired, this promotion can require accompanying measures for non-intermittent technologies to achieve an outcome that is cost-minimal for a country. The necessary measures increase with more demanding targets for renewables.

As a complement to the conceptual analysis, we develop and apply a numerical model with the objective to derive a quantification of potential policy and market design adjustments for the Swiss electricity market as well as the role of regional markets and approaches. Due to the findings from the conceptual work, such as the decoupling of the demand and the supply side, the numerical model focuses on the supply side of the electricity market. The model provides an aggregated formulation of Switzerland and its neighboring countries to account for import and export related transmission aspects and includes strategic company behavior for the Swiss market. The model is used to assess investment incentives under an energy only market framework, a capacity market, a feed-in premium for renewables, and a green quota mechanism, as well as combinations of renewable and capacity support. In addition to the current market design with a single Swiss electricity market price zone, we evaluate whether

[2] Depending on wholesale prices, a move from cost based regulation to liberalization might thus require accompanying changes to supply-side policies (i.e. if companies facing financial troubles after the liberalization are to be supported).

a split into a Northern and Southern zone would provide benefits and require policy adjustments.

The results for a scenario framework up to 2050 show that, without support mechanisms, Switzerland will more strongly rely on imports after the nuclear phase-out; renewable investments are likely to appear rather late once electricity prices are sufficiently high and investment costs sufficiently low. Until then, complementing the Swiss hydro production with imports is the cheapest supply option.

A faster development of renewable energy in Switzerland consequently requires support mechanisms like a feed-in tariff (i.e. the current KEV framework), feed-in premiums (i.e. the direct marking approach that is part of the Energy Strategy 2050) or a quota system. Our analysis illustrates that using a price-based mechanism, like feed-in premiums, will require a well-tailored support level to induce sufficient investments. Quantity-based approaches, like a technology-neutral capacity market or a renewable quota framework, would ensure investments in accordance with the mechanism’s targets. Furthermore, both a capacity market and a quota system could be abused in case of strategic company behavior. As those markets would be limited to Switzerland, the small size could provide sufficient incentives for strategic market power abuse. A corresponding market design would have to account for these challenges (for example by linking capacity and energy provision in capacity markets).

In line with the conceptual findings, the different policy scenarios also highlight that if a specific level of domestic production in form of available domestic generation capacities is desired, a pure focus on renewable support instruments is most likely insufficient and accompanying measures are needed. A combination of capacity and quota mechanism would allow reaching both, a renewable investment trajectory and a pre-defined level of local available dispatchable generation. However, there are substantial interactions between these two instruments that depend on the level of competition, making a robust design complicated. Our results thus illustrate the difficulties of a simultaneous implementation of several interacting instruments.

The impact of a zonal configuration of the Swiss market is modest. Switzerland will remain a transit hub for electricity deliveries towards Italy. A zonal split will make the difference between the hydro exporting South and the import-dependent (after the nuclear phase-out) demand centers in the North more visible. The importance for those aspects only arises if also the underlying Swiss quantity targets are to be split between the regions and zonal capacity and quota mechanisms are implemented.

Zusammenfassung

Der Schweizer Strommarkt steht aktuell vor grossen Veränderungen. Im Zuge der Energiestrategie 2050 soll der derzeitige Anteil von Kernenergie langfristig durch erneuerbare Energien ersetzt werden. Im Rahmen der zweiten Phase der Strommarktliberalisierung soll der Markt auch für kleine Verbraucher geöffnet werden. Und letztlich werden auch weiterhin europäische Marktentwicklungen starke Auswirkungen auf den Schweizer Strommarkt haben. Im Zuge dieser Veränderungen und Herausforderungen wird das heutige Marktdesign eventuell angepasst werden müssen, was eine Justierung existierender und eine Einführung neuer Politikinstrumente erfordern könnte. In diesem Zusammenhang werden in diesem Projekt drei verwandte Themen untersucht.

Erstens untersuchen wir, ob und wie politische Massnahmen in Strommärkten interagieren, ob diese koordiniert werden müssen, und ob imperfekter Wettbewerb auf dem Endkundenmarkt zu Problemen auf der Angebotsseite führt. Zweitens sollen die Auswirkungen verschiedener Politik- und Marktdesignanpassungen für den Schweizer Markt simuliert und quantifiziert werden. Schliesslich erweitern wir die quantitative Analyse, in dem wir die Rolle regional differenzierter Markt- und Politikstrukturen untersuchen. Der erste Teil des Projekts erlaubt eine Abschätzung, wie politische Interventionen in Wechselbeziehung stehen, und zeigt Optionen zur Koordinierung der Instrumente auf. Basierend auf diesen Erkenntnissen können dann in der numerischen Analyse gezielte Politikszenarien für die Schweiz abgebildet werden.

Für unsere theoretische Analyse haben wir ein konzeptionelles Modell des Strommarkts entwickelt. Die Nachfrageseite dieses Modells bildet eine unvollständige Strommarktliberalisierung[3] ab. Wir sind dabei davon ausgegangen, dass der Endkundenmarkt aufgrund einer beschränkten Wechselbereitschaft der Kunden sowie Netztransportgebühren Charakteristiken eines unvollkommenen Wettbewerbs aufweist, welche es Anbietern erlaubt, Marktmacht auszuüben. Wir haben dieses Nachfragemodell mit einem Produktionsmodell gekoppelt, in welchem Anbieter in zwei verschiedene Technologien investieren können: einerseits in planbar einsetzbare Kraftwerke (z.B. Wasserkraft), anderseits in fluktuierende Erzeugung (z.B. Wind oder Sonne). Zudem bildet das Modell einen Spotmarkt für Importe und Exporte ab, auf welchem die Anbieter zumindest beschränkten Einfluss auf den Strompreis haben können. Innerhalb dieses Modellsetups haben wir die verschiedenen nachfrage- und angebotsseitigen Politikmassnahmen analysiert.

[3] Unter unvollständiger Marktliberalisierung verstehen wir, dass der Markt für alle Konsumenten liberalisiert ist, ein Teil der Kunden den Anbieter aber wegen Marktfriktionen und anderen Hindernissen nicht wechselt, obwohl dies sich finanziell lohnen würde.

Unsere Resultate zeigen, dass in einem liberalisierten Strommarkt nachfrage- und angebotsseitige Probleme beinahe perfekt entkoppelt sind, obwohl die Firmen sowohl auf dem Endkundenmarkt als auch auf dem Spotmarkt Marktmacht haben. Entsprechend können Interventionen auf der Nachfrageseite (wie z.B. staatliche Preisvergleichsportale und Anpassung von Netzgebühren) und Interventionen auf der Angebotsseite (z.B. Feed-in Premiums und Kapazitätsmärkte) separat koordiniert werden. Diese Schlussfolgerung gilt jedoch nur für die im Rahmen des Modells getroffene Annahme eines liberalisierten Strommarktes. Bei einem Wechsel von der momentanen Marktstruktur mit „gefangenen" Endkunden zu freier Anbieterwahl dürfte eine übergreifende Koordination erforderlich sein, da die regulierten Endkundentarife es erlauben, Erzeugungskosten durchzureichen, was nach der Liberalisierung nicht mehr möglich ist.[4]

Weiter ist es für Firmen mit einem grossen Kundenstamm aufgrund der Trägheit der Kunden profitabel, höhere Preise zu setzen als kleinere Anbieter. Ein Zugang zu einem ausreichend liquiden und grossen Spotmarkt (wie den europäischen Märkten) ist in diesem Rahmen von grosser Bedeutung. Dieser Zugang ist zentral für die im Modell identifizierte Trennung zwischen Angebots- und Nachfrageseite und hilft, effiziente Investitionen auf der Angebotsseite zu sichern sowie die notwendige Koordination politischer Massnahmen zu reduzieren.

Unsere Resultate zeigen auch, dass trotzdem auf der Angebotsseite eine Koordinierung von Politikmassnahmen notwendig ist. Falls fluktuierende Erneuerbare gefördert werden, was in den meisten industrialisierten Ländern der Fall ist, können begleitende Massnahmen für planbare Technologien notwendig sein, um ein kostenminimales Ergebnis zu erreichen wenn zugleich ein vorgegebenes Mass an verfügbarer, inländischer Erzeugungskapazität erreicht werden soll. Je anspruchsvoller die Ziele für erneuerbare Energien dabei sind, desto notwendiger werden begleitende Massnahmen.

Als Ergänzung zur konzeptionellen Analyse haben wir ein numerisches Modell entwickelt, um mögliche Politik- und Marktdesignanpassungen für den Schweizer Strommarkt und die Rolle regionaler Märkte zu quantifizieren. Basierend auf den Erkenntnissen aus der konzeptionellen Arbeit, dass die Nachfrage- und Angebotsseite im einem liberalisierten Markt entkoppelt sind, liegt der Fokus des numerischen Modells auf der Angebotsseite des Strommarkts. Das Modell beinhaltet eine aggregierte Formulierung der Schweiz und der Nachbarländer, um der import- und exportbezogenen Übertragungsaspekte Rechnung zu tragen, und bildet strategisches Firmenverhalten für den Schweizer Markt ab. Das Modell

[4] Solche Massnahmen wären notwendig, wenn Versorger die nach der Marktöffnung aufgrund ihrer Kostenstruktur in finanzielle Schwierigkeiten geraten unterstützt werden sollen.

wurde in diesem Projekt eingesetzt, um Investitionsanreize in einem Energy-Only Markt, bei einem Kapazitätsmarkt sowie im Falle von Fördermassnahmen für erneuerbare Energien (Feed-in Premium sowie Quotenmechanismus) zu analysieren. Ebenfalls simuliert wurde eine Kombination aus Förderung für Erneuerbare und Kapazität. Zudem haben wir abgeschätzt, ob eine Unterteilung des Schweizer Marktgebietes in eine Nord- und eine Südzone Vorteile bringen könnte und Politikanpassungen erfordern würde.

Die Ergebnisse einer Szenarienanalyse bis 2050 für die verschiedenen Politikmassnahmen zeigen dabei, dass die Schweiz ohne zusätzliche Unterstützungsmechanismen nach dem Kernenergieausstieg stärker auf Importe angewiesen sein wird. Umfassende Investitionen in erneuerbare Energien finden wahrscheinlich erst nach dem Ausstieg statt, wenn sowohl die Strompreise gestiegen als auch die Investitionskosten weiter gefallen sind. Bis dahin ist eine Ergänzung der lokalen Wasserkraftproduktion durch Importe die kostengünstigste Versorgungsalternative. Ein schnellerer Ausbau erneuerbarer Energien erfordert daher zusätzliche Förderinstrumente wie Einspeisetarife (wie die aktuelle KEV), Einspeiseprämien (wie der geplanten Direktvermarktung) oder ein Quotensystem.

Die Unsicherheit der zukünftigen Preis- und Kostenentwicklungen erschwert auch die Festlegung der ‚richtigen' Tarifhöhe bei preisbasierten Förderinstrumenten für erneuerbare Energien (wie Einspeisetarifen oder –prämien). Mengenbasierte Instrumente, wie der simulierte Quotenmechanismus oder ein technologieneutraler Kapazitätsmarkt, sichern entsprechend ihrer Vorgaben zeitnahe Investitionen. Allerdings erlauben sie aufgrund ihrer Marktgrösse (fokussiert auf Schweizer Anbieter) in deutlich stärkerem Ausmass strategisches Verhalten der Anbieter als die durch die europäische Marktentwicklung dominierten Spotmärkte. Ein entsprechendes Marktdesign sollte daher dieser Herausforderung Rechnung tragen (z.B. durch eine Verknüpfung von Kapazitätsgeboten und Energiebereitstellung bei Kapazitätsmärkten).

Die Simulationen stützen zudem die Ergebnisse des konzeptionellen Modells, dass zusätzliche Massnahmen neben der Förderung erneuerbarer Energien erforderlich sind, wenn ein vorgegebenes Level an einheimischer Versorgung (in Form von verfügbarer inländischer Erzeugungskapazität) erzielt werden soll. Durch eine Kombination von Kapazitäts- und Quotensystemen könnten beide Ziele erreicht werden, dabei ergeben sich jedoch komplexe Interaktionen der Instrumente. Diese sind zudem stark von den Annahmen über die Möglichkeiten der Marktmachtausübung abhängig, was eine robuste Ausgestaltung solcher Systeme erschwert. Die Studie zeigt somit die Schwierigkeiten auf, die der zeitgleiche Einsatz verschiedener interagierender Instrumente mit sich bringt.

Die Ergebnisse der zonalen Aufteilung des Schweizer Marktgebietes in einen durch Wasserkraft dominierten Süden und einen durch Kernkraft (bis zum Ausstieg) und grosse

Nachfragezentren geprägten Norden sind moderat. Sie offenbaren durch die damit sichtbareren lokalen Import- und Exportstrukturen zwar die Unterschiede der Regionen, auf die allgemeine Rolle der Schweiz als Transitland und die hohe Bedeutung der Exporte nach Italien hat die zonale Aufteilung keine Auswirkung. Deutlichere Verschiebungen ergeben sich nur dann, wenn auch die politischen Zielvorgaben (für Quoten- oder Kapazitätsvorgaben) auf zonaler Ebene definiert werden.

Résumé

Le marché suisse de l'électricité connait actuellement des changements majeurs. Dans le contexte de la Stratégie énergétique 2050, la part actuelle de l'énergie nucléaire doit être remplacée à long terme par des énergies renouvelables. Lors de la deuxième phase de la libéralisation du marché de l'électricité, le marché doit également être ouvert aux petits consommateurs. L'évolution du marché européen continuera par ailleurs d'avoir un fort impact sur le marché suisse de l'électricité. En raison de ces changements et de ces défis, la conception actuelle du marché devra éventuellement être adaptée, ce qui pourrait nécessiter l'ajustement des instruments de politique existants et l'introduction de nouveaux instruments. Dans ce contexte, trois sujets connexes sont étudiés dans ce projet.

Tout d'abord, nous examinons si et comment les mesures politiques interagissent sur les marchés de l'électricité, si elles doivent être coordonnées et si une concurrence imparfaite sur le marché des utilisateurs finaux entraîne des problèmes du côté de l'offre. Deuxièmement, les effets de différentes adaptations de la politique et de la conception des marchés doivent être simulés et quantifiés pour le marché suisse. Enfin, nous élargissons l'analyse quantitative en examinant le rôle des structures de marché et des politiques régionales différenciées. La première partie du projet permet d'évaluer comment les interventions politiques sont en corrélation et montre des options pour coordonner les instruments. Sur la base de ces résultats, des scénarios politiques ciblés pour la Suisse peuvent alors être présentés dans l'analyse numérique.

Pour notre analyse théorique, nous avons développé un modèle conceptuel du marché de l'électricité. Dans ce modèle, il y a une libéralisation du marché incomplète au niveau de la demande[5]. Nous avons supposé que le marché de détail se caractérise par une concurrence imparfaite en raison de la propension à changer limitée des clients et des coûts de transport du réseau, ce qui permet aux fournisseurs d'exercer un pouvoir de marché. Nous avons couplé ce modèle de demande avec un modèle de production dans lequel les fournisseurs peuvent investir dans deux technologies différentes: dans des centrales électriques pouvant être exploitées de manière planifiable (par exemple l'énergie hydroélectrique), d'une part, et dans la production fluctuante (par exemple l’énergie éolienne ou solaire), d’autre part. En outre, le modèle constitue un marché au comptant pour les importations et les exportations sur lequel les fournisseurs peuvent avoir au moins une petite influence sur le prix de l'électricité. Dans le

[5] Dans le cadre d'une libéralisation du marché incomplète, le marché est libéralisé pour tous les consommateurs, mais une partie des clients ne change pas de fournisseur, même si cela en vaudrait la peine financièrement.

cadre de ce modèle, nous avons analysé les différentes mesures politiques au niveau de la demande et de l'offre.

Nos résultats montrent que sur un marché libéralisé les problèmes liés à la demande et à l'offre sont presque parfaitement dissociés, bien que les entreprises aient un pouvoir de marché aussi bien sur le marché de détail que sur le marché au comptant. En conséquence, les interventions au niveau de la demande (telles que les sites comparateurs de prix de l'Etat et l'adaptation de la taxe pour l'utilisation du réseau) et les interventions au niveau de l'offre (p. ex. les primes d'injection et les marchés de capacité) peuvent être coordonnées séparément. Toutefois, cette conclusion ne s'applique que dans le cadre de l'hypothèse d'un marché libéralisé de l'électricité adoptée dans le modèle. Le passage de la structure actuelle au libre choix des fournisseurs devrait nécessiter une coordination globale, étant donné que les tarifs réglementés pour les utilisateurs finaux permettent de transférer les coûts de production, ce qui n'est plus possible après la libéralisation[6].

En outre, il est rentable pour les entreprises disposant d'une vaste clientèle de fixer des prix plus élevés que les fournisseurs plus petits en raison de l'inertie de leurs clients. L'accès à un marché au comptant suffisamment liquide et à grande échelle (comme les marchés européens) revêt une grande importance. Cet accès est essentiel pour la séparation entre l'offre et la demande caractérisant le modèle et contribue à assurer des investissements efficaces au niveau de l'offre, ainsi qu'à réduire la coordination nécessaire des mesures politiques.

Nos résultats montrent également qu'une coordination des mesures politiques est toutefois encore nécessaire du côté de l'offre. Si les énergies renouvelables fluctuantes sont encouragées, ce qui est le cas dans la plupart des pays industrialisés, des mesures d'accompagnement peuvent être requises pour des technologies planifiables pour obtenir un résultat efficient au niveau des coûts, pour autant qu'un certain niveau prédéfini de capacité de production disponible soit souhaité. Plus les objectifs en matière d'énergies renouvelables sont ambitieux, plus des mesures d'accompagnement s'avèrent indispensables.

En complément de l'analyse conceptuelle, nous avons développé un modèle numérique pour quantifier les adaptations possibles de la politique et de la conception du marché pour le marché suisse de l'électricité et le rôle des marchés régionaux. Sur la base des résultats des travaux conceptuels, à savoir que la demande et l'offre sont dissociés dans un marché libéralisé, le modèle numérique met l'accent sur l'offre du marché de l'électricité. Le modèle comprend une formulation agrégée de la Suisse et des pays voisins, afin de tenir compte des

[6] De telles mesures s'avèreraient nécessaires si l'on souhaitait soutenir des fournisseurs en difficultés financières après l'ouverture du marché en raison de leur structure de coûts.

aspects de transfert liés à l'importation et à l'exportation et illustre le comportement stratégique des entreprises pour le marché suisse. Le modèle a été utilisé dans le cadre de ce projet pour analyser les incitations à l'investissement dans un marché «Energy-Only», un marché de capacité, ainsi que dans le cas de mesures d'encouragement des énergies renouvelables (prime d'injection et mécanisme de quotas). En outre, nous avons évalué si une subdivision de la zone de marché suisse en une zone nord et une zone sud pourrait apporter des avantages et nécessiterait des ajustements politiques.

Les résultats d'une analyse de scénarios jusqu'en 2050 pour les différentes mesures politiques montrent qu'en l'absence de mécanismes de soutien supplémentaires après la sortie de l'énergie nucléaire, la Suisse devra compter davantage sur les importations. Des investissements de grande envergure dans les énergies renouvelables n'interviendront vraisemblablement qu'après la sortie du nucléaire, lorsque les prix de l'électricité auront augmenté et les coûts d'investissement diminué. Compléter la production hydraulique suisse avec des importations constitue jusque-là l'alternative la plus rentable. Un développement plus rapide des énergies renouvelables requiert ainsi des mesures de soutien tels que des rétributions à l'injection (comme le système actuel), des primes à l'injection (comme prévu avec la commercialisation directe) ou un système de quotas.

L'incertitude quant à l'évolution future des prix et des coûts rend également difficile la détermination du tarif «exact» s'agissant des instruments d'encouragement basés sur les prix pour les énergies renouvelables (comme les tarifs ou les primes d'injection). Les instruments basés sur le volume, tels que le mécanisme de quotas simulé ou un marché de capacité technologiquement neutre, garantissent des investissements rapides conformément aux objectifs. En raison de leur taille de marché (axée sur les fournisseurs suisses), ils permettent toutefois un comportement nettement plus stratégique des fournisseurs que les marchés au comptant soumis à l'évolution du marché européen. Une conception de marché correspondante devrait donc tenir compte de ce défi (par exemple en liant mise à disposition de capacités et d'énergie pour les marchés de capacité).

Les simulations étayent également les résultats du modèle conceptuel. Pour autant qu'un certain niveau d'approvisionnement domestique est souhaité (sous forme de capacité de production nationale disponible), des mesures supplémentaires en plus de l'encouragement des énergies renouvelables peuvent s'avérer nécessaires. Une combinaison de systèmes de quotas et de capacité permettrait d'atteindre les deux objectifs que sont la production domestique et le développement des énergies renouvelables. Mais une telle implémentation va de pair avec d'importantes interactions entre les deux instruments. Ces dernières dépendent fortement des hypothèses concernant la présence de pouvoir de marché, ce qui complique une conception robuste d’un tel système. L’étude illustre ainsi les difficultés que cause l’emploi simultané de deux instruments politiques qui interagissent.

Les résultats de la division du marché suisse en une zone sud dominée par l’énergie hydroélectrique et une zone nord caractérisée par l’énergie nucléaire (jusqu'à la sortie du nucléaire) et les grands centres de demande sont modérés. En rendant les structures locales d'importation et d'exportation plus visibles, ils révèlent les différences entre les régions. La division en zones n’a toutefois aucun impact sur le rôle général de la Suisse en tant que pays de transit et la grande importance des exportations vers l'Italie. Des écarts significatifs ne s’observent que si les objectifs politiques (pour les exigences en matière de quotas ou de capacité) sont définis au niveau de la zone.

1. Introduction

Swiss electricity markets are subject to several large-scale changes. Market power is to be reduced with the second phase of market liberalization, renewables are intended to replace nuclear power, and substantial investments in the grid and short-term storage have to be made and funded.

To facilitate these changes, a set of different policy and regulatory measures is already used, planned, or discussed, such as feed-in tariffs, market deregulation, a potential introduction of capacity markets and possible changes to grid tariffs. The different instruments and regulatory changes may interact strongly. For example, as shown in Thoma und Krysiak (2012), feed-in tariffs can have strongly differing implications, when there is more or less market power. Similarly, instruments such as capacity markets or different types of grid tariffs will interact with instruments promoting renewables and, depending on their design, can hamper or facilitate a reduction of market power. Thus instruments and regulatory changes need to be coordinated.

In addition to this coordination on the national scale, it might be beneficial to use zonal configurations that facilitate a coordination of interventions on a subnational level. Such configurations could consist of zonal pricing or even a broader differentiation of policy interventions, such as regional promotion of renewables, or incentives for a regional matching of demand and supply. Zonal configurations could help in congestion management, could reduce the demand for new power lines and storage, and might lead to a more efficient promotion of renewable energy. However, they could also lead to substantial price differences, cause allocation inefficiencies, and hamper market liberalization.

In this project, we address the question of how interventions in electricity markets need to be coordinated and what the potential benefits and disadvantages of zonal configurations of the Swiss electricity system are. These two major research questions are investigated separately.

In the first part of the project, we develop a conceptual model of an electricity market to analyze the interactions among the promotion of renewables by a feed-in premium, (full) market liberalization, transport costs of electricity (in order to differentiate between local and abroad production), and capacity payments in a conceptual model analytically.[7] To depict market liberalization, we use an approach in which we account for the well-documented hesitancy of consumers to switch suppliers by introducing fixed “costs” of switching. In order

[7] We focus on feed-in premium and capacity payments to keep a comparability of both renewable and capacity support relying on a similar subsidy like structure.

to account for the temporal structure of supply and demand (grid capacity and peak loads, storage capacity and fluctuating demand and supply), the supply side of the model follows the approach of Krysiak (2009, 2011) and Thoma und Krysiak (2012), where variations in supply or demand are described as uncertain events in a context of a two-stage model (investment and production stage with uncertainty in the investment stage).

This analysis yields insights into the pathways in which the effects of these instruments are interrelated provided options for coordinating them. Based on these results, policy recommendations regarding the coordination of political interventions are formulated.

In the second part of the project, we develop and apply a numerical model with the objective to derive a quantification of potential policy adjustments for the Swiss electricity market. Due to the findings from the conceptual work in the first project part, the numerical model focuses on the supply side of the Swiss electricity market including the three largest suppliers modelled as separate firms with strategic behavior in terms of investment decision and plants operation while the remaining suppliers are modelled in aggregate as a competitive fringe without strategic behavior. The Swiss market is interlinked to the neighboring countries Germany, France, Italy, and Austria by linear import-export functions. The model further includes a regional structure of the Swiss electricity market that allows analyzing possible regionally differentiated electricity market designs.

The main results obtained within this project resulted in two scientific papers. The first paper focuses on the conceptual work regarding policy interactions and coordination from the first project and the second paper describes the quantitative analysis using the numerical model from the second project part. These two papers feed into this report as separate chapters.

This report is structured as follows. Chapter 2 consists of the first scientific paper that includes a description of the structure of the conceptual model and the results of the theoretical analysis regarding policy interactions and coordination. The paper rounds down with conclusions and policy recommendations. Chapter 3 presents the second paper on the numerical model development and the quantitative analysis of different electricity market designs including zonal configurations. The paper further provides a summary of important results and policy recommendations. Chapter 4 concludes the report by formulating key policy conclusions overarching the findings from both project parts.

2. Coordinating Policy Interventions on Imperfectly Competitive Markets: The Case of Electricity Markets

This chapter presents the first paper describing the conceptual work carried out in the scope of the first part of the project. The paper analytically explores how political interventions in electricity markets interact and if they need to be coordinated, and whether an imperfectly competitive retail market induces problems on the supply side. The results of the paper yield insights into the pathways in which the effects of these political interventions are interrelated and provide options for coordinating the instruments.

The paper is structured as follows: Section 1 provides an introduction to the research field, the methodology and the research question followed by the literature review in Section 2. Section 3 then provides a detailed description of the conceptual electricity market model developed and applied. Key conceptual model results are first presented in Section 4 and then quantified in Section 5 based on a data set representing the Swiss electricity market. Finally, Section 6 concludes the paper.

2.1. Introduction

During the past decades, electricity markets in many countries have been subject to far-ranging changes. Many markets have been liberalized, that is, end consumers have been granted the right to choose their supplier. This has often induced adjustments in payment schemes for infrastructure (e.g., grid tariffs). Furthermore, most industrialized countries use policy measures to promote renewables, such as feed-in premiums, feed-in tariffs or renewable portfolio standards, and several countries have introduced or discuss capacity markets or payments for capacity to improve national security of supply.

Given the multitude of market interventions involved in this process, the question arises whether these interventions need to be coordinated. This question is of particular interest, as both retail and wholesale markets for electricity are not yet perfectly competitive in many countries and thus problems might spill over from the retail market to investments, or vice versa. A prominent example of an imperfect liberalization[8] is Germany. Although liberalization

[8] With the term *imperfect liberalization*, we understand the situation where a market is liberalized and all consumers have the option to switch suppliers, but due to the existence of some consumers' hesitance to switch, not all of them do, although it would economically pay off. The imperfect liberalization should not be confused with a *partial market liberalization*, where the market is only liberalized for a certain part of the market (e.g. only for major customers).

was implemented more than a decade ago in Germany, only a small set of consumers have switched to new providers (less than 25% of consumers switched till 2013) and many still retain rather expensive original contracts (around one third of consumers in 2015) (Bundesnetzagentur, 2016). The question is whether the obviously remaining market power has implications for the effects of other market interventions, such as feed-in premiums.

The economic literature on energy policy rarely accounts for simultaneous market interventions, and, if it does, the analysis is usually a numerical analysis that is confined to specific countries. Furthermore, to the best of our knowledge, there is currently no model that links the often observed outcome of electricity market liberalization, where substantial price differences persist and consumers do not realize possible savings by switching to a new provider, with supply side aspects. But such a model is necessary to analyze the consequences of an imperfect market liberalization for interventions on the electricity market.

In this paper, we first develop a new model of an imperfectly liberalized electricity market. In this model, a market that consisted of regional monopolies is liberalized, that is, consumers get the right to choose a supplier that originally served another region. However, consumers differ in their willingness to actually switch to a provider with a lower price, so that providers retain some power to charge differing prices. This hesitancy to switch can be amplified by grid tariffs. We extend this model by adding a supply side, where suppliers invest in production capacity and buy or sell on a spot market. Thereby, suppliers have to choose among technologies with qualitatively different characteristics, such as renewables with intermittent (random) production and a controllable technology (e.g., hydropower or coal-fired power plants). Furthermore, suppliers are big enough to exert some influence on the price on the spot market.

Using this model, we study whether and how market interventions need to be coordinated. In particular, we consider grid tariffs, feed-in premiums for renewables, and capacity payments for the controllable production technology.

Our results show that, despite imperfect competition on the retail and the spot market, there is an almost perfect decoupling of the demand and the supply side. Retail price differences and the distribution of demand among suppliers do not depend on supply-side policies and aggregate investment is not altered by remaining market power on the imperfectly competitive retail market. Furthermore, our results show which consequences a liberalization of a retail market with imperfect competition and grid tariffs have for retail prices and how the promotion of renewables interacts with capacity payments.

2.2. Review of the literature

The research objective of our paper and the underlying model combine two streams of academic literature: the design and interaction of policy measures aiming at the supply side of markets and the role of switching costs and market liberalization on the demand side. Furthermore, in both streams the role of strategic company behavior and market power plays a crucial role.

In the academic literature, there exists a wide range of studies addressing direct impacts of political interventions on achieving policy targets in electricity markets. A large fraction of those interventions aims at environmental targets (i.e. flue-gas emissions, CO_2 emissions). Further justifications for policy interventions are innovation externalities (i.e. spill-over), technological lock-in, hold-up problems due to uncertainty, information and behavioral aspects, transaction costs, macro-economic aspects (i.e. employment, import/export), supply security and basic service provision. In hand with the multitude of reasons for interventions there exists a similar large scale of methodologies and policy designs, ranging from classic command and control instruments (input or output control, technology standards), over market-based and financial approaches (taxes, subsidies, permit systems) to institutional approaches (liability, information-based approaches).

However, indirect effects resulting from interactions between different instruments and measures are less intensively investigated. Following the Tinbergen rule (Tinbergen, 1952) one should apply as many policy instruments as independent targets are to be achieved to ensure an efficient outcome. Thus, an instrument-mix often occurs when simultaneous problems are considered (i.e. beside environmental externalities there are asymmetric information problems, market power, uncertainties etc.).

Following Sorrell and Sijm (2005) the resulting interaction of instruments can be clustered in direct interaction, indirect interaction, and trading interaction. Each of these interactions has consequences on the efficiency and effectiveness of the applied instruments. A large fraction of the literature analyzing policy interactions looks at the interplay of price- and quantity-based instruments. Combinations of different price instruments are less prominent. Nevertheless, there are potential motivations for such combinations, e.g. in the case of market power on the supply side (Barnett, A. H. (1980), Conrad (1987)). For electricity markets, and energy markets in general, the interaction of renewable support with environmental, competition or sectoral policies is of particular importance (i.e. see Fischer and Preonas (2010) for a review on different renewable support instruments and their interaction).

There exists a growing body of empirical and model-based literature that aims at quantifying the different interaction effects, especially for renewable and emission polices (i.e.

see Gonzalez (2006) for an overview and Rathmann (2007), Böhringer and Rosendahl (2010), Thoma and Krysiak (2012), Weigt et al. (2013) amongst others for applications). A second field of interest in policy interactions are energy efficiency-related instruments (i.e see del Rio (2010), Harmsen et al. (2011), and Meran and Wittmann (2012)). Finally, system stability, security of supply, and investments aspects in electricity generation are getting increasing attention (i.e. see Hoeffler and Wambach (2013) for the coordinating of network and generation investments, Joskow and Tirole (2007) and Joskow (2008) for capacity investments, or Bunn and Muñoz (2016) for renewable support and resource adequacy).

Within this paper, we take up these policy assessments. We focus on renewable support, capacity payments, and transmission costs while accounting for strategic firm behavior. However, the framework is designed to be generic in the sense that further policy interventions can be included and evaluated.

On the market demand side we extend the policy debate by also including the impact of market liberalization on firm behavior and consequently the efficiency of policy interventions. With the restructuring process in electricity markets end-consumers could choose their suppliers and competition was not only initiated between generators aiming at participating in the wholesale market but also between utilities fighting for market shares. Consequently, on the demand side our paper is related to the switching cost literature initiated with the seminal papers by Klemperer (1987a,b).[9] Many switching costs models address the trade-off between maximizing current profits by exploiting non-switching loyal customers (termed 'harvesting' effect) and maximizing future profits by attracting new customers via low prices (termed 'investing' effect). Normally, a large consumer base is considered beneficial for firms as this increases the amount they can extract from non-switching customers. However, in a dynamic setting also the market share of other firms becomes an important determinant as smaller firms typically bid more aggressive. Consequently, it can even become attractive to not obtain a too large market share in order to reduce competitive pressure (Schmidt, 2010).

Following Fabra and García (2015), a third effect is the 'current switching' effect when firms attract new customers as a source of current profits. They compare the different incentives stemming from switching consumers with taxes and subsidies. For large firms with more loyal consumers that can be exploited the switching costs are a form of subsidy that allows them to keep higher prices. For firms with a smaller customer base as a starting point, the switching costs are equivalent to a tax they have to account for when bidding for new customers. In a dynamic setting, Fabra and García (2015) show that the trade-off between the

[9] See Klemperer (1995) and Farrell and Klemperer (2007) for reviews on switching costs approaches and literature.

different effects strongly depends on the degree of market share symmetry, with symmetric markets being more competitive.

We focus in our demand side representation on the static switching effect and neglect dynamic pricing strategies over the long run. Given the structure of many electricity markets we also assume rather asymmetric market shares and consequently expect a price increasing effect of switching costs. Linked with the supply side we aim to understand whether the competition on the consumer side has an impact on supply side strategies and policies and vice versa.

Related to the theoretical literature on switching cost effects is the question why consumers are hesitant to switch. Within electricity markets the product is perfectly homogenous and switching in many markets only requires little effort. The monitoring report on the European electricity market (ACER/CEER, 2014) shows relative low numbers on consumer switching. Grubb (2015) and Klemperer (1995) provide a set of explanations for different switching costs, like searching, learning costs, or transaction costs. Wieringa and Verhoef (2007) add the aspect of liberalization to switching. Customers in newly liberalized markets were not used to switching before, often do not know other competing firms, and the firms themselves are unfamiliar with marketing activities. We do not address the underlying differentiation in switching cost explanations by assuming a linear increasing cost function for each market region. The reasoning for those switching costs can be based on a mixture of effects discussed in the mentioned literature. However, to obtain a switching pattern that resembles observed switching shares our developed model follows a similar logic as search cost approaches (i.e. see Wilson and Price (2010) for an empirical test of the UK electricity market and Giulietti et al. (2014) for a search model of the UK market).

2.3. The Model

We consider a setting where a total of n customers in N regions demand electricity that is supplied by N firms, each of which has been a monopolist in its region before market liberalization (see Figure 1).

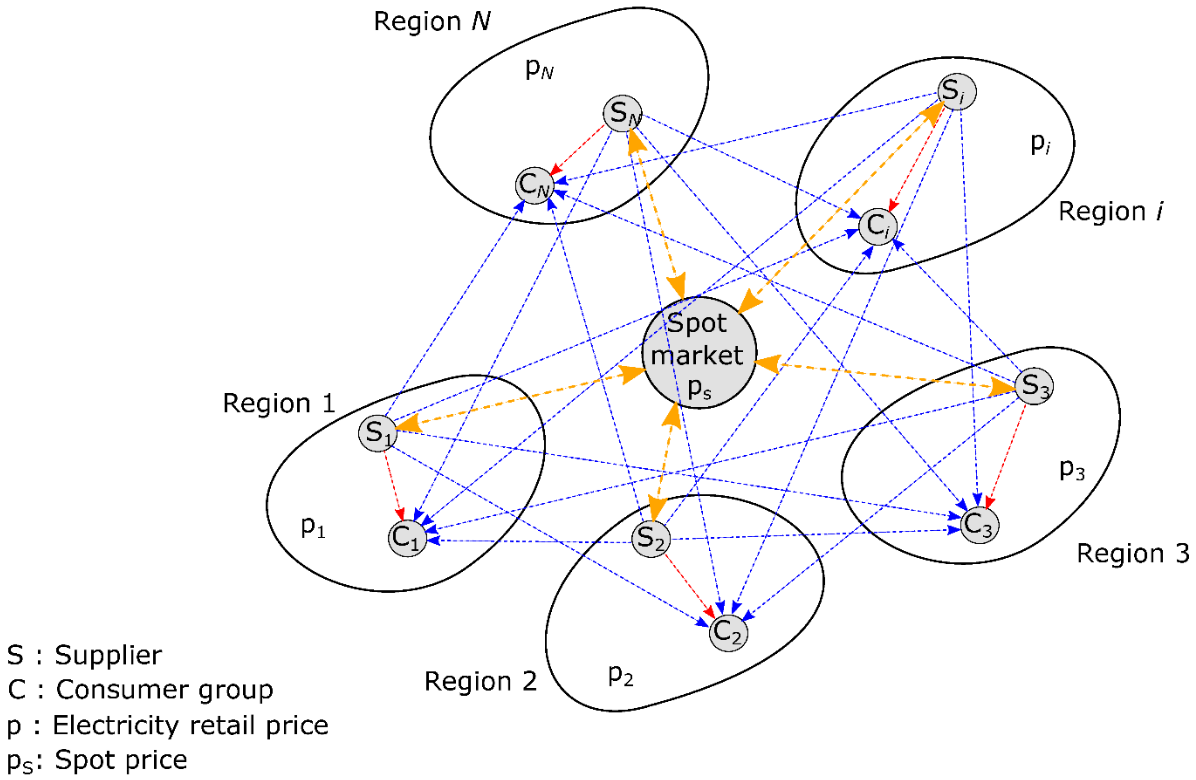

Figure 1: Structure of the model: Electricity market with N regions with one supplier and one consumer group in each region. After market liberalization, consumers can either buy electricity from their local supplier (red arrows) or switch to another region (blue arrows). Suppliers can trade electricity on the spot market (orange arrows).

Due to liberalization, the consumers can buy electricity from any of the N firms. However, as is apparent from the examples given above, consumers hesitate to switch providers and will only do so, if this leads to substantial savings. This hesitancy could result from actual switching costs (expenses of ending one and getting a new supply contract), could result from limited information, or limited attention to a good that is almost invisibly delivered and results in only a small share of total consumption expenditure.

Firms set a price for electricity and decide whether to produce electricity or buy on the spot market. If they produce electricity, they have the choice between two types of renewables with intermittent and stochastic production (e.g., wind and PV) and one controllable form of energy production (e.g., hydropower). The spot market is an international market.

We assume that all firms behave strategically both in setting their retail prices and in deciding their investments in production technologies.

The government intervenes in the market in several ways. First, it might influence the hesitancy of consumers to switch suppliers (e.g. by increased transparency regarding the conditions of the different suppliers in the market, providing price comparisons, or by forcing consumers to switch suppliers). Second, it sets the tariff for using the inter-regional grid. Finally, it grants subsidies for renewables and (possibly) a fixed payment for the projectable technology to increase domestic security of supply.

Using this setup, we will study whether and how governmental interventions need to be coordinated. In particular, we will analyze whether incomplete competition on the retail market has implications for supply-side policies, in particular, for policies to promote renewables, and vice versa.

2.3.1. Demand

We have N regions with totally n consumers. The number of consumers in region $i\ (i \in \mathbb{N} | i \leq N)$ is n_i. To simplify the exposition, we order regions in relation to their size, so that we have

$$n_i \geq n_{i+1} \quad (i < N). \tag{1}$$

As we will show later, this implies a similar ranking of retail prices p_i

$$p_i \geq p_{i+1} \quad (i < N). \tag{2}$$

We assume that each region i has a continuum of consumers (with total mass n_i) that differ regarding their hesitancy to switch providers. We model this hesitancy by introducing a fixed cost term for each switch of providers. These costs are given by $f_c\, f$ with f_c being a constant parameter (that could, e.g., be an indication of the market design) and $f \in [0,1]$ being an individual parameter of each consumer. Furthermore, we assume that, in each region, f is uniformly distributed over the continuum of consumers. If consumers are not supplied by the firm located in their region, they also have to pay a fixed grid tariff t_c. This cost represents an additional surcharge when buying electricity from another region and is solely a compensation for using the main grid and thus independent of the actual distance between supplier and provider.[10]

Each consumer demands one unit of electricity, irrespective of the price. At the beginning of market liberalization, consumers have a contract with their local supplier. Then, they receive offers from all other suppliers in a random sequence. Each offer is evaluated separately, that is, after each offer, a consumer decides whether to switch or not. A switch to provider s is

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[10] In most liberalized electricity markets, there is no additional cost for switching from the local supplier to a supplier in another region. In this case, t_c is 0. However, the introduction of the surcharge t_c allows us to differentiate between local and abroad production.

beneficial for consumer j who is located in region i and currently has a contract with supplier r if the savings in the electricity bill exceed the switching costs:

$$p_r - p_s > f_c\, f_j + \begin{cases} t_c & \text{if } r = i, \\ 0 & \text{otherwise.} \end{cases} \tag{3}$$

Based on this condition, we can define the marginal consumer from region *i* who would switch from his original supplier (i) to supplier s by

$$f_{i,s} = \frac{p_i - p_s - t_c}{f_c}, \tag{4}$$

as well as the consumer from region i who would, after having switched to supplier r, switch again to supplier s

$$F_{r,s} = \frac{p_r - p_s}{f_c}. \tag{5}$$

Note that the grid tariff is only relevant for the first switch, as it is identical whenever a consumer has a contract with a supplier from outside of his region.

Given this model, it is obvious that a consumer will only switch to a provider with a lower price. Thus given Condition (2), a consumer will only switch from a (larger) region i to a (smaller) region j and never in the opposite direction[11].

In order to avoid distinctions of cases, we assume that at least one consumer who switched (only) from his home region i to the next smaller region $i + 1$ will not further switch (not even to the cheapest provider in region N). Consequently, the individual parameters of the two relevant marginal consumers have to fulfil $f_{i,i+1} > F_{i+1,N}$, and expressed in prices:

$$p_i + p_N > 2\, p_{i+1} + t_c. \tag{6}$$

This model describes consumers who are not fully optimizing: Most of them neither switch always when a lower price is offered nor do they look for the very best offer when they switch. Only consumers with a very low hesitancy to switch will certainly end up with the cheapest possible contract. Most consumers will either not switch at all or end up with a cheaper but not the cheapest provider.

We thus describe a situation where most consumers do not care enough about their electricity bill to exercise efforts in collecting information. Given that electricity accounts only for a very small share of consumption expenses, this appears to be a plausible characterization. Furthermore, it is useful to describe the effects of market liberalization

[11] According to Eq. (1), this translates into $j > i$. In our model, region sizes n_i decrease with increasing index i. Consequently, indices of larger regions have to be lower than indices of smaller regions.

observed in countries, such as Germany: Despite considerable price differences, only few consumers have switched to a new provider and the provider offering the lowest price gets many but not all consumers that switch providers.

To complete the model, we derive the demand for each firm after the switching process has fully taken place. As the switching process is rather complex, we start with two regions, provide the result for three regions, and finally the demand for N regions.

For two regions, consumers switch only from region 1 to region 2, if $p_1 > p_2$. Thus we get

$$D_1 = n_1(1 - f_{1,2}), \tag{7}$$

$$D_2 = n_2 + n_1 f_{1,2}. \tag{8}$$

For three regions, the situation is more complex. In region 1, some consumers will retain their old contract, some will take the offer from the provider with the lowest price (3), and some will first get an offer from the intermediate price provider (2) and switch to this provider. From these last mentioned consumers, some will switch again to provider 3 and some will not.

This leads to the following demand structure:

$$D_1 = n_1(1 - f_{1,3}), \tag{9}$$

$$D_2 = \frac{n_1}{2}(f_{1,2} - F_{2,3}) + n_2\,(1 - f_{2,3}), \tag{10}$$

$$D_3 = \frac{n_1}{2}(2f_{1,3} - f_{1,2} + F_{2,3}) + n_2\, f_{2,3} + n_3. \tag{11}$$

The consumer share $n_1(f_{1,2} - F_{2,3})$ is allocated to D_2 and D_3 on half each since these consumers get random offers from providers 2 and 3 with equal probabilities. Due to their respective switching cost levels, these consumers will then not further switch and therefore stay after one switch.

Finally, in the general case of N regions, demand for firm i can be written as

$$
\begin{aligned}
D_i = {} & n_i\left(1 - f_{1,N}\right) \\
& + \sum_{j=1}^{N-3} \sum_{k=N-i+1}^{N-j-1} \frac{n_j}{k}\left(F_{N-k,N-k+1} - F_{N-k+1,N}\right) \\
& + \sum_{j=1}^{i-1} \frac{n_j}{N-j}\left(f_{j,j+1} - F_{j+1,N}\right) + \sum_{k=N-i+1}^{N-1} n_i\left(f_{N-k,N-k+1} - f_{N-k+1,N}\right) \\
& + \sum_{k=N-i+1}^{N-1} \sum_{m=N-k+1}^{N-1} n_i\left(f_{N-k,m+1} - f_{N-k,m}\right) \\
& + \sum_{j=1}^{i-2} \sum_{m=1}^{i-j-1} \frac{n_i}{N-j-m}\left(f_{j,j+m+1} - f_{j,j+m}\right) \\
& + \sum_{j=1}^{i-2} \sum_{k=N+1-i}^{N-j-1} \sum_{m=i+k-N}^{k-1} \frac{n_j}{k+1}\left(F_{N-k,N-k+m+1} - F_{N-k,N-k+m}\right) \\
& + \sum_{j=1}^{i-3} \sum_{k=N+2-i}^{N-j-1} \sum_{m=1}^{i+k-N-1} n_j \frac{k-m+1}{(k+1)(k-m)}\Big(F_{N-k,N-k+m+1} \\
& - F_{N-k,N-k+m}\Big).
\end{aligned}
\tag{12}
$$

Note that, as all $f_{i,j}$ and all $F_{i,j}$ are linear functions of prices, the demand system is linear in prices.

2.3.2. Supply

Each firm has to supply its customers at each moment of time. It can produce electricity with two technologies: A renewable technology with random production and zero marginal costs (e.g., PV or wind) and a technology with controllable production that has non-zero marginal costs (e.g., largescale hydropower). If the firm falls short of producing the required amount of electricity, it has to buy the remaining electricity on the spot market; if production exceeds demand, the firm sells on the spot market.

For being able to produce, the firm has to invest in production capacity, which then strictly limits the maximum quantity that can be produced with each technology. For simplicity, we assume that the renewable technology either produces at full capacity or not at all with fixed and known probabilities.

The firm makes decisions in two stages. In a first stage, it decides about investment and the price that it offers to consumers. At this stage, the firm knows the probability with which the renewable technology will yield an output but not whether it will actually produce. At the second stage, the firm knows if and how much the renewable technology produces and can choose the production of the controllable technology and how much electricity to buy or sell on the spot market.

This setting implies that firms set constant retail prices for end consumers but that the wholesale market is a spot market with varying prices where electricity is traded under full information regarding the actual output from renewables.

Consider first the second step. Let c denote the marginal costs of the controllable and $\tilde{q}_i$ qi the quantity produced with this technology by firm i. Let z_i be the capacity of the renewable technology that firm i has invested in and let p_s denote the price on the spot market. The cost of meeting demand D_i are then given by

$$C_i = c\,\tilde{q}_i + p_s(D_i - \tilde{q}_i - (1-\phi)\,z_i), \tag{13}$$

where $\phi \in \{0,1\}$ is a random variable that describes whether the renewable technology produces or not. Note that we assume that this random variable (i.e., weather conditions) always takes on the same value for all producers.

The price on the international spot market is assumed to be a linear function of the aggregate imports/exports:

$$p_s = c + \Delta + b \sum_{i=1}^{N} (D_i - \tilde{q}_i - (1-\phi)\,z_i). \tag{14}$$

Here, Δ denotes the difference between marginal costs of the controllable technology and the price on international market, if there are no exports or imports. Note that the price on the spot market will depend on the production of the renewable technology and thus be a random variable.

Regarding the production uncertainty, we denote the probability that the renewable technology produces $(\phi = 0)$ by Ω and the probability that the renewable technology does not produce $(\phi = 1)$ by $1 - \Omega$.

In the first stage, investment decisions are made. For technology, we assume linear investment costs $\mu\,q_i$, where q_i is the installed capacity of this technology. For the renewable technology, we assume that the costs depend on locations, that good locations are scarce, and that firms compete for those locations. Thus, investment costs per unit of capacity are increasing in total installed capacity: $\nu_0 + \nu \sum_{j=1}^{N} z_j$. Thus total investment costs of firm i equal

$$C_i^I = \mu\,q_i + \left(\nu_0 + \nu \sum_{j=1}^{N} z_j\right) z_i. \tag{15}$$

Finally, we assume that all firms behave strategically, that is, when making their decisions, they account for the effect of their decisions on demand and the spot market price as well as on the decisions of the other firms.

2.3.3. Market interventions

The final actor in our model is the government that uses different interventions to pursue different objectives. As we aim at analyzing policy interactions, we take different policy objectives and typical interventions aimed at meeting these objectives as given and do not discuss whether they are economically reasonable.

A first objective pursued in many countries is a reduction and harmonization of regional end consumer prices. Typically, this objective is pursued by increasing competition via making supplier switches easier (e.g. by improved transparency and user-friendly internet platforms supporting supplier switching[12]) or by altering grid tariffs. We account for these policy measures by varying f_c (overall hesitancy to switch providers) and t_c (grid tariffs).

Second, most countries aim at increasing the supply of electricity from renewables. To this end, feed-in tariffs, feed-in premiums or renewable portfolio standards are often used. In this paper, we focus on feed-in premiums for renewables. For each unit of electricity produced by the renewable technology, a subsidy σ_Z is granted to the producing firm. As final demand is inelastic in our model, this is equivalent to a feed-in premium that is funded via a general surcharge on electricity paid by end consumers.

Finally, countries may aim for a certain level of controllable domestic generation capacity. In a world with intermittent production from renewables, this implies that investments into controllable technologies might require support.[13] Typical policy measures are capacity markets or subsidies. For simplicity, we assume that a subsidy σ_Q is paid for each unit of capacity (not production) of the controllable technology.

2.4. Model Analysis and Results

The above model can be used to study the interaction among the different objectives and policy measures discussed above. The first and most important question is whether imperfections on

[12] For example, in the UK, the *Energy Switch Guarantee* (https://www.energyswitchguarantee.com/), an internet platform that supports an easier supplier switching, has been introduced by 13 larger and smaller energy providers.

[13] Here, one has to differentiate between small and large countries. While for larger countries, the availability of capacity of controllable technologies is crucial for supply security, this is different for smaller countries, since due to their size they will always be able to import electricity if needed when intermittent technologies are not running.

the retail market have an effect on investment. As we assume that suppliers behave strategically not only with regard to setting their retail prices but also regarding production and investment, this is a likely outcome.

However, we get the following rather strong result.

Proposition 1. *The retail market and the firms' investment decisions are decoupled in the following sense:*

1. *Retail price differences, and thus the distribution of final demand among suppliers, are independent from investment costs, feed-in premiums, and the subsidy for the controllable technology.*
2. *Aggregate investment in the controllable technology and aggregate investment in the intermittent technology are independent of the hesitancy to switch suppliers and of the distribution of final demand among suppliers.*

Proof. Let us first consider the second stage of the firms' decision problem, where they decide about use of the controllable technology. In this stage, firm i's profit is given by

$$D_i\, p_i - \left(c\, \tilde{q}_i + p_s(D_i - \tilde{q}_i - (1-\phi)\, z_i)\right) - C_i^I, \tag{16}$$

where ϕ is known and where D_i is already set through the (still unknown) price decision in stage one. Optimizing w.r.t. $\tilde{q}_i$, leads to

$$\tilde{q}_i^{int} = \frac{\Delta}{(N+1)b} + D_i - (1-\phi)\, z_i. \tag{17}$$

As firm i has an available capacity of q_i and can produce only positive amounts, the optimal production level in stage two is thus $\tilde{q}_i^* = \max\left\{0, \min\left\{q_i, \tilde{q}_i^{int}\right\}\right\}$. As we will show below, all firms will always be in the same case (as the random variables are identical for all firms).

If the firm sets $\tilde{q}_i^* = q_i$ or $\tilde{q}_i^* = 0$, the spot market price p_s depends solely on decision variables of the first stage. If the firm sets $\tilde{q}_i^* = \tilde{q}_i^{int}$, the resulting spot market price is $p_s = c + \Delta/(\mathrm{N}+1)$ which is constant.

Firm i's expected profit in stage one can be written as

$$D_i\, p_i - \mathcal{E}\left(c\, \tilde{q}_i^* + p_s(D_i - \tilde{q}_i^* - (1-\phi)\, z_i)\right) - C_i^I, \tag{18}$$

where D_i depends on the complete set of retail prices. From our analysis of the second stage and from (14), we know that p_s depends only via the sum of the D_j on retail prices. As this sum always equals total demand n, which is constant, p_s is independent of p_i. Thus optimizing (18) w.r.t. p_i yields

$$p_i = \mathcal{E}(p_s) - \frac{D_i}{\frac{\partial D_i}{\partial p_i}}. \tag{19}$$

As $\mathcal{E}(p_s)$ is the same for all firms and as D_i is linear in all prices (cf. Eqs. (12) and (4)–(5)), price differences among firms depend only on demand-side parameters and on $f_c,\ t_c$. Now Eqs. (12) and (4)–(5) imply that the distribution of final demand among suppliers depends only on price differences, not the price level. Thus, this distribution also depends only on demand-side parameters and $f_c,\ t_c$. This proves the first assertion.

Given this information, we can take D_i as being constant in Eq. (18) when optimizing firm profits w.r.t. their investment decisions. Let us first consider the case, where $\tilde{q}_i^* = q_i$ regardless of the value ϕ. In this case, optimizing Eq. (18) w.r.t. q_i yields

$$q_i^* = D_i - z_i\Omega + \frac{\Delta - \mu + \sigma_Q}{(N+1)\,b}. \tag{20}$$

As we always have $\sum_{j=1}^{N} D_j = n$, the sum of the above investments in the controllable technology is independent from all demand-side parameters and variables (as Assertion 3 states), if this holds for all z_i.

Using this result, we get the following conditions for z_i

$$z_i^* = \frac{\left(\mathrm{c} + \mu - \sigma_Q + \sigma_Z\right)\Omega - \nu_0}{(N+1)\,(\nu + b\,\Omega\,(1-\Omega))}. \tag{21}$$

Obviously, this condition does not include any demand-side variables or parameters.

The other cases ($\tilde{q}_i^* = \tilde{q}_i^{int}$ and $\tilde{q}_i^* = 0$, for $\phi = 0$, and $\tilde{q}_i^* = q$, for $\phi = 1$) can be treated in the same way and show that the demand-side parameters and variables only enter the equations via D_i, if at all, (see Appendix A.1). Hence, aggregate investment in the controllable technology and aggregate investment in the intermittent technology are independent of demand-side variables and parameters. This proves Assertion 2.

Furthermore, the firms' investments in the intermittent technology only differ in D_i, if at all. Together with 17 and 20, this implies that all firms will always be in the same case of production decisions, as conjectured above.

Proposition 1 is both a surprisingly strong and highly relevant result. It is strong as it implies an almost complete separation of demand- and supply-side problems despite the intermediate market (spot market) being only imperfectly competitive. It is relevant, because it implies that even in case of substantial market imperfections, policies need not to be fully coordinated. In particular, there is no need to use different policies to promote renewables in reaction to a more or less competitive retail market.

The main drivers of this result are the assumptions that (a) total demand is price-inelastic and that (b) the price on the international market reacts linearly to domestic production changes. Both assumptions are of course not perfectly true. However, the first assumption is plausible at least in the short run; most estimates of price elasticities for electricity demand suggest a very minor response to price changes in the short run. The second assumption is easily defensible as a first approximation whenever the domestic market is small in comparison to the international market, so that domestic production changes lead to small adjustments on the international market.

But even if the assumption are poor approximations in some cases, Proposition 1 still implies that spillovers between demand- and supply-side problems can only result from indirect effects driven by the influence of a single firm on total demand or on total imports/exports. Except for cases with very few firms, these effects will be small indicating that an overall policy coordination is at most of minor importance.

Given this result, we can analyze the demand- and the supply-side separately.

2.4.1. The Demand Side

We first analyze the demand-side. The following proposition provides a first basic result.

Proposition 2. *Whenever $f_c > 0$ or $t_c > 0$, the firms' retail prices differ. Firms that have supplied a larger region before market liberalization will set higher prices in the equilibrium, that is, $n_i > n_j \Rightarrow p_i > p_j$.*

Proof. We start by observing that the demand system (Eqs. (12) and (4)–(5)) is linear in prices and region sizes. Furthermore, by Proposition 1, the only differences between two firms that are relevant for their choice of retail prices are the sizes of their original regions. A firm's price-setting problem (as described in Eq. (18)) is thus square in the firm's price, linear in all other prices and linear in the region size. Such a problem has a unique and continuous solution that is linear in the region size. As this holds for all firms and as firms differ only by the size of their original region, we either have $n_i > n_j \Rightarrow p_i > p_j$ or $n_i < n_j \Rightarrow p_i < p_j$ or $p_i = p_j$ for all $i, j \in \{1, \dots, N\}$.

Therefore, it suffices to show that $n_1 > n_2$ implies $p_1 > p_2$. By Eqs. (12) and (4)–(5), we have

$$D_1 = n_1\left(1 - \frac{p_1 - p_N - t_c}{f_c}\right), \tag{22}$$

$$D_2 = \frac{n_1}{N-1}\left(\frac{p_1 - p_2 - t_c}{f_c} - \frac{p_2 - p_N}{f_c}\right) + n_2\left(1 - \frac{p_2 - p_N - t_c}{f_c}\right). \tag{23}$$

Note that this demand system has been derived under the assumption that $n_i > n_j \Rightarrow p_i > p_j$ (see Sect. 3.1).

Given Prop. 1, the price-setting problem of firm i can be written as $\max_{p_i \geq 0}(p_i - \gamma)\, D_i$ with some constant $\gamma \geq 0$. This leads to price difference between firm 1 and firm 2 in the market equilibrium of

$$p_1^* - p_2^* = \frac{3\, f_c + 5\, t_c + p_N - \gamma}{4\,(2\, n_1 + n_2)}. \tag{24}$$

As we need to have $p_N \geq \gamma$ in the market equilibrium (otherwise, firm N would not be active), we have $n_1 > n_2 \Rightarrow p_1 > p_2$, which by our above argument implies $n_i > n_j \Rightarrow p_i > p_j$ for all $i, j \in \{1, \dots, N\}$. Thus our assumption in Sect. 3.1 has been consistent.

It remains to show that the opposite assumption, $n_i > n_j \Rightarrow p_i < p_j$ results in an inconsistency. To see this, consider the case $N = 2$ with $t_c = 0$ and $n_2 > n_1$. In this case, the difference in equilibrium prices derived from Eqs. (7)–(8) is $p_1^* - p_2^* = f_c(n_1 - n_2)/(3\, n_1)$. Thus $n_2 > n_1$ would imply $p_2 > p_1$, so that $n_i > n_j \Rightarrow p_i < p_j$ cannot hold.

This proposition is highly intuitive from an economic perspective. When choosing its price, each firm has to balance three effects. A reduction of the price charged by the firm can attract new customers from firms with higher prices, convince some of its own customers not to switch to firms with lower prices and it reduces the revenue from its own customers that do not switch at all. The latter two effects are proportional to the size of the firm's own region. The first effect is proportional to the size of the region with the higher price. Thus a firm with a smaller original region has an incentive to set a more aggressive price, as it can attract many new customers from larger regions and revenue losses in its own region are small (as the region is small). On the other hand, a firm with a larger original region can gain less from trying to attract new customers (as most other regions are smaller) and lose much revenue in its own region by setting a lower price.

Proposition 2 implies that our model describes an imperfectly liberalized market. Although consumers have full freedom to choose their supplier, their hesitancy to switch gives suppliers the opportunity of strategic pricing and leads to different suppliers setting different prices.

The following proposition shows how the resulting set of prices can be influenced.

Proposition 3.

1. *Reducing n_N, that is, the size of the smallest region, leads to reduced prices in all regions.*
2. *Reducing f_c leads to lower prices in all regions and to a smaller difference between the highest and the lowest price.*
3. *Reducing t_c leads to a smaller difference between the highest and the lowest price.*

Proof. Following Proposition 2, the firm with the smallest region size n_N sets the lowest price p_N. For $1 \leq i < N$, all D_i include p_N only in the form of $\alpha\ (p_i - p_N)$ with $\alpha < 0$ (cf. Eqs.(12) and (4)–(5)). Thus reducing p_N is equivalent to a downward shift of the demand functions in all regions $i \in \{1, \ldots, N-1\}$. Due to the linearity of the demand system, this leads to a reduction of prices in all regions. This proves Assertion 1.

For Assertions 2 and 3, we observe that we can write demand in region i as

$$D_i = n_i + \frac{\delta_i}{f_c} t_c - \sum_{j=1}^{N} \frac{\beta_{i,j}}{f_c} p_j, \tag{25}$$

with $\delta_1 > 0, \delta_N < 0, \beta_{i,i} > 0$, and $\beta_{i,j} \leq 0$, for $i \neq j$.

Thus the first-order condition of the maximization problem derived in Prop. 2 (i.e., $\max_{p_i \geq 0}(p_i - \gamma)\, D_i)$ can be written as

$$f_c\, n_i + \delta_i\, t_c - \sum_{j=1, j\neq i}^{N} \beta_{i,j}\, p_j = \beta_{i,i}(2\, p_i - \gamma). \tag{26}$$

This is a set of linear equations describing the firms' reaction functions. An increase in f_c leads to an outward shift in all these functions and thus to increase in all prices. Furthermore, as f_c enters multiplied by n_i, this effect is larger in big regions (which, by Prop. 2 already have high prices) than in smaller regions (which have lower prices). Thus an increase in f_c also leads to an increase of the price spread.

Finally, due to the values that δ_i can take, an increase in t_c leads to an increase of the highest price (p_1) and a reduction of the smallest price (p_N) and thus also to a higher price spread.

Again, this proposition is intuitive. Proposition 2 implied that firms with a smaller original customer base use more aggressive pricing. Proposition 3 adds that this behavior induces lower prices in all regions.

More willingness to switch leads to higher incentives to fight for customers and thus to more competition and lower prices. It also reduces the price differences. In fact, for $t_c = 0$, $t_c \to 0$ leads to all prices converging to the spot market price.

Similarly, a reduction of grid tariffs also reduces the maximal price spread, as the highest-price firm (which can only lose customers) can retain less customers and the lowest-price firm (which can never lose its original customers) can more easily convince customers to switch. However, the effect on the firms in between can differ, as these firms both have to attract and retain customers.

These results have straight-forward implications for the market design. First, allowing newcomers that do not have an original customer base to enter the market will reduce end consumer prices. This is a simple way to enhance competition in electricity markets. Second, grid tariffs are important to fund infrastructure maintenance and extensions. However, use-based grid tariffs (as modeled here) reduce competition on the retail market (as local providers have an advantage) and thus increase overall price differences. Fixed tariffs would not induce this problem.[14]

2.4.2. The Supply Side

We now turn to the supply side. The first interesting question is what happens in case of no policy interventions on the supply side. The following proposition provides this information as a benchmark for the subsequent investigation.

Proposition 4. *Assume that* $v_0 > (c + \mu)\,\Omega$. *Then, without market interventions, there will be no investment in the renewable technology.*

1. *If the controllable technology is always running at full capacity, total investment will equal*

[14] Use-based grid tariffs incur only when consumers buy electricity from another (non-local) supplier in an abroad region. The use-based grid tariff then compensates for the use of the transmission grid when transporting electricity from abroad to the home region. As use-based grid tariffs do not incur when buying electricity in the home region, the local provider has an advantage over its abroad competitors which reduces competition and leads to an increase in overall price differences. Fixed (in contrast to use-based) tariffs incurring independent from the supplying region do not favor any provider and would therefore not induce this problem.

$$q_{tot} = n + \frac{N\,(\Delta - \mu)}{b\,(N+1)}. \tag{27}$$

Thus, if $\Delta < \mu$, the country will import electricity, and if $\Delta > \mu$, it will export.

2. *If the controllable technology is not always running at full capacity, total investment will equal*

$$q_{tot} = n + \frac{N\,(\Delta\,(1-\Omega) - \mu)}{b\,(N+1)(1-\Omega)}. \tag{28}$$

Thus, if $\Delta\,(1-\Omega) < \mu$, the country will import electricity, and if $\Delta\,(1-\Omega) > \mu$, it will export.

Proof. Without subsidies, the firm gains the same revenue from each unit of produced electricity, regardless of the production technology. For $\nu_0 > (c+\mu)\,\Omega$, the first unit of renewables has higher total costs per unit of expected production, than the controllable technology (where all units of investment induce the same costs).[15] Thus all investment will be in the controllable technology. If there are no renewables, production and thus the spot market price is constant. Solving the investment problem and aggregating over firms for all possible cases directly leads to Eqs. (27) and (28).

This proposition provides the rather obvious insight that if renewables have higher expected total costs per unit of production than the controllable technology, they will only be used with market interventions. The second, and more important, result is that even without intermittent production, and given a constant market price, a country will usually require imports and exports to match demand and supply at all points of time. This is hardly surprising to economists, but stands in marked contrast to the energy strategies of many countries. If a country wants to meet domestic demand solely with own production, policy interventions are required. Both results are not surprising per se. However, it is interesting to see that these insights, which are usually connected to perfectly competitive markets, also hold under imperfect competition both on the retail and on the spot market.

Now let us consider a government that intervenes on the market by subsidizing the production from renewables and the capacity of the controllable technology. Its objective is to

[15] As ν_0 is the investment cost of the first capacity unit and Ω is the operation probability of the renewable technology, the total cost of the first unit of expected production is ν_0/Ω. With $c+\mu$ being the total production cost of the controllable technology, $\nu_0 > (c+\mu)\,\Omega$ implies that the first unit of renewables has higher total costs per unit of expected production, than the controllable technology.

achieve a given level of installed capacity of renewables and a minimal level of always deployable domestic production capacity, in case the renewables do not produce:

$$\sum_{i=1}^{N} z_i = \varrho_Z \, n \, , \tag{29}$$

$$\sum_{i=1}^{N} q_i \geq \varrho_Q \, n \, , \tag{30}$$

with given targets $\varrho_Z, \varrho_Q \geq 0$.

It is rather obvious that a subsidy for renewables can be used to achieve the first target. What is economically interesting is to investigate the need to coordinate the subsidy for renewables and the capacity subsidy.

To calculate the subsidy σ_Q that is necessary to achieve the above targets, we have to consider two different cases. In case the controllable technology is even used at full capacity, if the renewable technology produces, we get:

$$\sigma_Q \geq \mu - \Delta + \frac{b \, n \, (N+1)}{N} \, (\varrho_Q + \varrho_Z \, \Omega - 1). \tag{31}$$

This case is the relevant case, whenever

$$\varrho_Q \leq \frac{N \, \Delta}{b \, n \, (N+1)} + (1 - \varrho_Z). \tag{32}$$

In the second case, the controllable technology is used below its capacity (according to Eq. (17)) whenever the renewable technology produces and is used at full capacity otherwise. In this setting we get

$$\sigma_Q \geq \mu - \Delta \, (1 - \Omega) + \frac{b \, n \, (N+1)}{N} \, \big(\varrho_Q - 1\big)(1 - \Omega). \tag{33}$$

This case is relevant for

$$\frac{N \, \Delta}{b \, n \, (N+1)} + (1 - \varrho_Z) < \varrho_Q \leq 1 + \frac{N \, \Delta}{b \, n \, (N+1)} \, . \tag{34}$$

For higher targets, the capacity would never be used completely, so that these targets do not make sense.

Note that the subsidy is increasing from the first to the second case with an increasing ϱ_Q. Note further that higher targets for the renewable technology also lead to a higher subsidy for the controllable technology.

Together, these points prove the following result.

Proposition 5. *All targets up to* $\varrho_Q = 1 + N\,\Delta/(b\,n\,(N+1))$ *can be met with the subsidy scheme. However, subsidies for the different technologies need to be coordinated. A higher target for renewables or a higher target for the controllable technology both demand a higher* σ_Q.

The reason why the subsidies need to be coordinated is obvious: More renewables imply lower spot market prices and thus less incentives to invest in the controllable technology.[16] The subsidy for the controllable technology increases less strongly for higher targets, because the technology is less often used at full capacity, facilitating strategic production behavior, which increases the profit per produced unit of electricity.

This proposition has intuitive but important implications. If the domestic availability of always deployable capacity is a policy target, a promotion of renewables has to be supplement with a support for non-intermittent technologies. This support could stem from subsidies based on capacity, as modeled here, or from a capacity market. Production-based subsidies will not work well, as the controllable technology is used in less and less cases, the more renewables are introduced into the system.

So far, we investigated a case where firms have the option to invest in one controllable and one renewable technology. For the remainder of our paper, we extend the model by adding a second intermittent renewable technology. This allows us to investigate optimal policies for a government that wants to introduce a given share of renewables at lowest costs (and does not care about technology choices or the domestic availability of always deployable capacity). Let A and B be the two renewable technologies, and denote the probabilities that A and B produce by Ω_1, that only B produces by Ω_2, that only A produces by Ω_3, and that no renewable technology produces by $1 - \Omega_1 - \Omega_2 - \Omega_3$.

Proposition 6. *Assume that a cost-minimizing government aims at achieving a total capacity of intermittent renewables of* $\varrho_{AB}\,n > 0$, *in the case discussed in Proposition 4, and that*

$$\varrho_{AB} > \frac{\nu_{A,0} - \nu_{B,0} + (\Omega_2 - \Omega_3)\,(c+\mu)}{2\,n\,\nu_B + b\,\Omega_2(1 - \Omega_1 - \Omega_2) + b\,\Omega_3(\Omega_1 + \Omega_2)}, \tag{35}$$

$$\varrho_{AB} < \frac{\nu_{B,0} - \nu_{A,0} + (\Omega_3 - \Omega_2)\,(c+\mu)}{2\,n\,\nu_A + b\,\Omega_3(1 - \Omega_1 - \Omega_3) + b\,\Omega_2(\Omega_1 + \Omega_3)}. \tag{36}$$

[16] This result will be relevant mostly for larger countries, where investments have a substantial impact on the spot market price. However, even for smaller countries like Switzerland, it shows that at least a coordination with foreign support schemes for renewables is important.

Then the government should subsidize both intermittent technologies. Except for special parameter combinations, the optimal subsidies σ_A, σ_B will have different values. Furthermore, a subsidy for the controllable technology can be optimal.

Proof. The expected social costs can be written as

$$\begin{aligned} c_{soc} = c\, q_{tot} + n\, \big(p_{s,1}\Omega_1 + p_{s,2}\Omega_2 + p_{s,3}\Omega_3 + p_{s,4}(1-\Omega_1-\Omega_2-\Omega_3)\big) \\ - p_{s,1}\Omega_1\big(q_{tot} + z_{A,tot} + z_{B,tot}\big) - p_{s,2}\Omega_2\big(q_{tot} + z_{B,tot}\big) \\ - p_{s,3}\Omega_3\big(q_{tot} + z_{A,tot}\big) - p_{s,4}\, q_{tot}(1-\Omega_1-\Omega_2-\Omega_3) + \mu\, q_{tot} \\ + z_{A,tot}(\nu_{A,0} + \nu_A\, z_{A,tot}) + z_{B,tot}(\nu_{B,0} + \nu_B\, z_{B,tot}). \end{aligned} \tag{37}$$

Here, q_{tot}, $z_{A,tot}, z_{B,tot}$ denote aggregate investments and $p_{s,1}, \ldots, p_{s,4}$ are the four spot market prices belonging to the four production cases of the intermittent renewables.

Minimizing Eq. (35) under the constraint that $z_{A,tot} + z_{B,tot} \geq \varrho_{AB}\, n$ and substituting the spot market prices shows that the optimal share of technology A among the intermittent renewables (i.e., $z_{A,tot}/(z_{A,tot} + z_{B,tot})$) is

$$\frac{\Omega_3(b\,\varrho_{AB}(\Omega_1+\Omega_2)+c+\mu)+\Omega_2(b\,\varrho_{AB}(1-\Omega_1+\Omega_2)+c+\mu+\nu_{B,0}-\nu_{A,0}+2\,\nu_B n\,\varrho_{AB})}{\varrho_{AB}\,(b\,(\Omega_2+\Omega_3+2\,\Omega_2\Omega_3-\Omega_2^2-\Omega_3^2)+2\,n\,(\nu_A+\nu_B))}, \tag{38}$$

Under the conditions stated in the proposition, this share is strictly greater than zero and strictly smaller than one, so that both intermittent renewables should be used. By Prop. 4, these will only be used in case subsidies are granted.

Analyzing the values of σ_A, σ_B that are necessary to achieve the optimal share (38) in the cases discussed before Prop. 5 shows that, apart from special cases, such as $\nu_A = \nu_B \wedge \nu_{A,0} = \nu_{B,0} \wedge \Omega_2 = \Omega_3$, the subsidies will differ.

Finally, the optimal investment in the controllable technology (i.e., q_{tot}) equals

$$\begin{aligned} &\frac{n\,b\,\big(\Omega_2^2+\Omega_2(\Omega_1\varrho_{AB}+2\,\Omega_3(\varrho_{AB}-1)-1)+\Omega_3(\Omega_3+\Omega_1\varrho_{AB}-1)\big)+b\,\big(\Omega_3^2(c+\Delta)\big)}{(b\,(\Omega_2^2-\Omega_2(2\,\Omega_3+1)+(\Omega_3-1)\,\Omega_3)-2\,n\,(\nu_A+\nu_B))} \\ &+\frac{n(-\Omega_3(2\,\Omega_2(c+\Delta)+\Delta-\mu+\nu_{A,0}-\nu_{B,0})+\Omega_2(c\,\Omega_2-\Delta\,(1-\Omega_2)+\mu+\nu_{A,0}-\nu_{B,0}))}{(b\,(\Omega_2^2-\Omega_2(2\,\Omega_3+1)+(\Omega_3-1)\,\Omega_3)-2\,n\,(\nu_A+\nu_B))} \\ &+\frac{n\big(2n(\nu_A(\varrho_{AB}(\Omega_1+\Omega_2)-1)+\nu_B(\varrho_{AB}(\Omega_1+\Omega_3)-1))\big)-2n(\Delta-\mu)(\nu_A+\nu_B)}{(b\,(\Omega_2^2-\Omega_2(2\,\Omega_3+1)+(\Omega_3-1)\,\Omega_3)-2\,n\,(\nu_A+\nu_B))}. \end{aligned} \tag{39}$$

Comparing this total investment with actual investment for the case, where the controllable technology always runs at full capacity (as given by (20)), shows that the optimal subsidy is

$\sigma_Q = \frac{\Delta-\mu}{N}$ and thus greater zero, whenever $\Delta > \mu$. For the other cases, a similar conclusion can be derived.

This final result shows that government interventions need to be fairly complex. Somewhat surprisingly, the subsidies for the intermittent renewables should differ between technologies. The reason is that the technologies have different production probabilities and different investment costs. As firms behave strategically, this leads to investment incentives that are distorted across technologies and thus need to be corrected by differentiated subsidies.[17] Furthermore, due to the competition for locations, there is also an externality between firms: A firm that builds renewables uses the best currently available locations, so that the investment costs increase for firms that want to build renewables afterwards. If this effect differs among technologies (i.e., if $\nu_A \neq \nu_B$), a differentiated subsidy is required to achieve a cost minimal solution.

The result has substantial practical relevance. It shows that there is some economic argument to use differentiated subsidies for renewables, as is current practice in most feed-in premium and feed-in tariff systems. The reason for this differentiation is the locational externality as well as market power on the spot market. In a perfectly competitive economy, the need for technology-specific subsidies would vanish.

2.5. Numerical Example

In order to illustrate the model and the model analysis described in Sections 3 and 4, we provide a numerical example that is based on data representing an electricity market comprising the four largest Swiss suppliers and their corresponding household customers.[18] The data includes the technical and economical characteristics of hydro, wind, and solar pv technologies as well as annual quantities of electricity sold by the suppliers to their customers.[19] Using this data, we investigate the possible impact of a full liberalization of the Swiss electricity market on the switching behavior of household customers and how the

[17] As firms have market power on the spot market, their investment decisions will usually deviate from socially optimal investments anyway. Prop. 6 implicitly shows that this does not only hold for total investment in renewables but also for the allocation among technologies.

[18] Considering only the four largest suppliers will likely overstate market power and thus prices. However, our investigations with more suppliers show that a setup with only four firms is sufficient to show the general direction of effects.

[19] An overview on all parameter values used for this analysis can be found in Table 2 in the appendix.

hesitancy of consumers to switching suppliers could affect retail prices. A detailed numerical analysis of supply side policies will be provided in the next Chapter.

As described in Section 3, we assume that before the liberalization, all (household) customers can only buy electricity from their local supplier. After the liberalization, the customers are free to choose their supplier. Figure 2 shows the quantities of electricity the suppliers sell to the consumers in each region before and after the liberalization (left axis) as well as the retail prices the firms set after the liberalization (right axis). Due to the consumers' hesitancy to switch suppliers, the firms exert market power on the retail market resulting in larger suppliers (i.e. suppliers with larger original home markets) setting higher prices than smaller suppliers (i.e. suppliers with smaller original home markets). As consumers are only willing to switch to suppliers offering a lower price, smaller suppliers serve consumers from more different regions than larger suppliers (see Figure 2). Partly due to the fact that consumers switch only in one direction (towards lower prices), we can observe that the aggregate demands of large suppliers becomes smaller after the liberalization, the opposite holds for small suppliers.

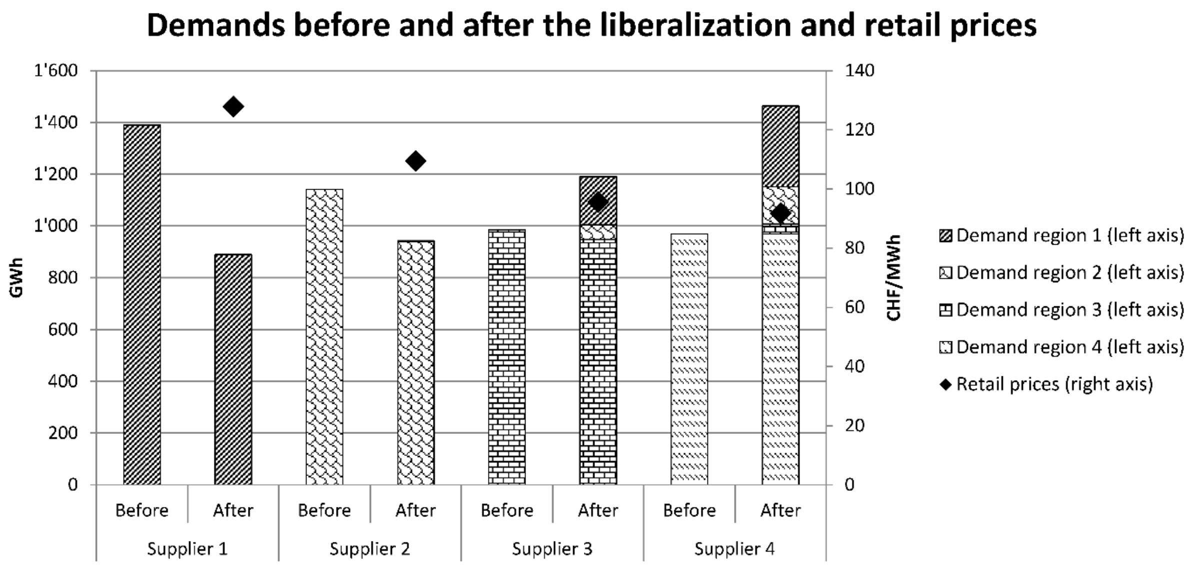

Figure 2: Retail prices and demanded quantities of electricity by supplier and region before and after a market liberalization.

Next, we analyze retail prices as a function of the constant fixed switching cost parameter f_c that describes the hesitancy of consumers to switch suppliers. As Figure 3 shows, retail prices in the entire market (linearly) increase with f_c. Additionally, larger suppliers set higher prices compared to their smaller competitors. This result illustrates that the existence of consumers' hesitancy to switch suppliers gives the suppliers the opportunity to exert market power and demand higher retail prices from their customers. A potential introduction of quantity-specific grid tariffs (represented by the parameter t_c) as a fee that consumers have to pay when buying electricity from another region reduces the attractiveness to switch from the local supplier to a supplier in another region and has different implications for the suppliers in the market. Whereas the large suppliers can increase their prices, due to the higher barrier for consumers to switch, the small suppliers have to decrease their prices in order to still attract customers from other regions (see Figure 4).

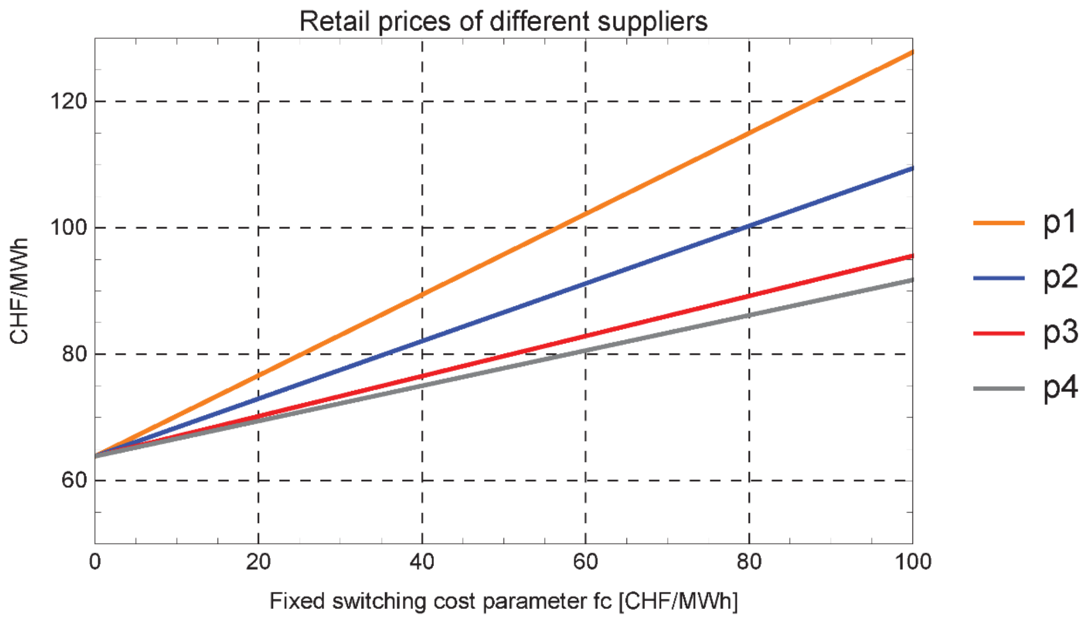

Figure 3: Retail prices set by suppliers after a market liberalization as a function of the fixed switching cost parameter f_c (grid tariff t_c is 0).

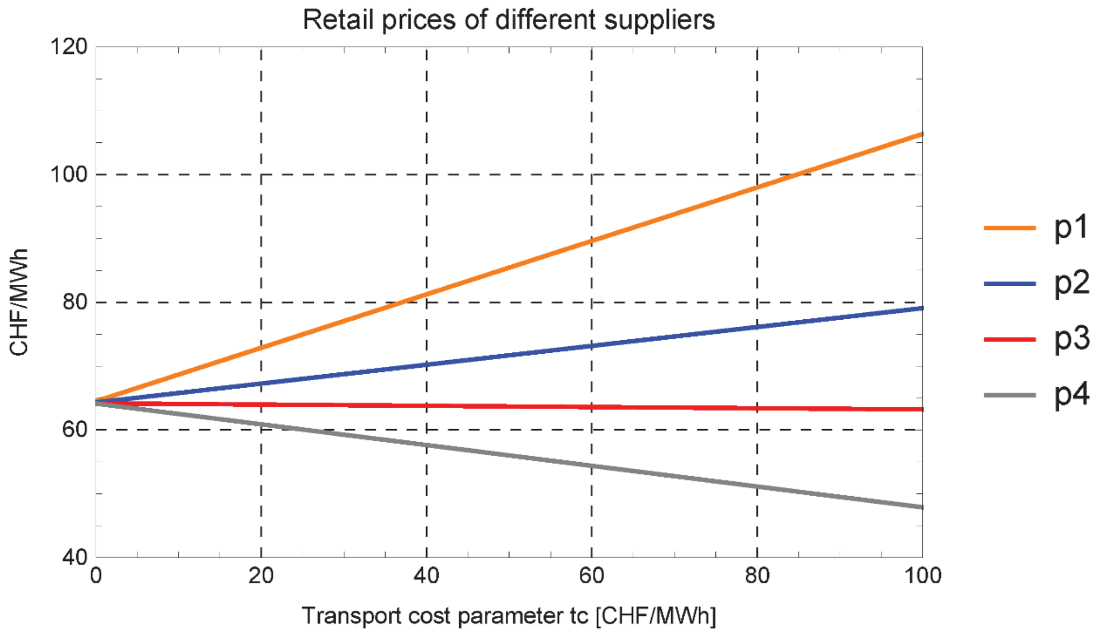

Figure 4: Retail prices set by suppliers after a market liberalization as a function of the grid tariff parameter t_c (fixed switching cost parameter f_c is close to 0).

2.6. Conclusions

In this paper, we have analyzed the questions whether interventions in electricity markets need to be coordinated and whether an imperfectly competitive retail market induces problems on the supply side. To answer these questions, we have developed a model of imperfectly liberalized electricity markets, where consumers hesitate to switch providers and where grid tariffs amplify this effect. We have coupled this demand-side model with a production model, where suppliers can invest into two different technologies, one with random production characteristics (intermittent renewables), and where producers can trade on an (also imperfectly competitive) spot market.

Our results show that demand- and supply-side problems are almost perfectly decoupled, even though firms have market power both on the retail and on the spot market. This result has to be seen as an approximation, because it is based on two simplifying assumptions[20]. However, it shows that, in a first step, policy should aim for coordinating interventions on the demand side (such as the support of supplier switching in a liberalized market and the structure

[20] Aggregate demand being constant and the international spot market being so much larger than the domestic market that a linear approximation of price reactions suffices.

of grid tariffs) and, separately, coordinating interventions on the supply side (such as feed-in premiums or tariffs and capacity markets).

Our results also indicate that, in particular on the supply side, a substantial coordination of policies is called for. If in addition to an increase in renewable generation a certain predefined level of dispatchable domestic production capacity is also desired, the promotion of renewables requires accompanying measures for these technologies, such as capacity payments or a capacity market. The necessary measures increase with more demanding targets for renewables, albeit at a diminishing rate.

To the best of our knowledge, this study provides the first theoretical model that connects an imperfectly competitive retail market for electricity with an investment model that includes the choice among technologies with qualitatively different characteristics (random vs. controllable production). Furthermore, it is the first paper to provide a model of an imperfect electricity market liberalization that can describe features found in several countries, like persistent and substantial price differences among a large set of suppliers.

Our results have some interesting implications for energy policy. Most importantly, they show that more care is required to coordinate interventions on electricity markets. They provide a novel argument as to why differentiated subsidies for renewables might be efficient. Furthermore, they emphasize that for a small country like Switzerland imports play an important role in supplying local demand. Consequently, if a predefined level of domestic controllable energy sources is desired, capacity payments will be needed in addition to renewable support.

Of course, our study has limitations. Most importantly, it shows that the above effects exist but cannot assess their actual relevance. The numerical example provided so far illustrates the general conceptual findings. For an assessment of the relevance and quantification for the Swiss policy context, a comprehensive numerical study that extends the work in this paper would be necessary. We will address those aspects for the supply side policies in the following section. Second, as highlighted above, our results hinge on some critical assumptions, such as fixed aggregate demand and the existence of a large international spot market. If these assumptions do not hold, additional effects will arise that may counteract some of the mechanisms in this paper. In particular, there will be some need to coordinate demand and supply-side policy.

3. Numerical Model and Analysis

This chapter presents the second paper describing the numerical work carried out in the scope of the second part of the project. The paper explores how policy and market design choices interact with network related aspects of the Swiss electricity market. In particular, we assess the question whether a zonal structure of the market and of the underlying policy approaches yields benefits. The results of the paper provide insights into the potential development of the Swiss electricity market under varying support frameworks. It highlights which elements of the underlying policy approaches need particular care if strategic company behavior is to be expected. It follows-up on the conceptual analysis provided in the previous section and explores whether some of the generic findings are of relevance for Switzerland. In particular, the supply side oriented finding and whether a combination of policies is needed will be addressed in addition to the assessment of network related challenges.

The study is structured as follows: Section 1 provides a short introduction to the research question. Section 2 provides a description of the underlying model and data for the scenario analysis. Section 3 provides an overview on the scenario outlet and Seciton 4 to 6 highlight the results for the different policy approaches under a uniform and zonal market configuration and discusses the underlying interaction mechanisms. Section 6 concludes the paper. An Annex with the numerical results provides a detailed overview for the various scenarios and sensitives.

3.1. Introduction

The envisioned energy transition of the Swiss Energy Strategy 2050 will induce profound changes on the Swiss electricity sector: renewables are intended to replace nuclear power, and the high level of supply security is to be maintained despite the higher supply volatility of renewables. The projected increase towards 11,4 TWh of renewable generation in 2035 will require substantial investments. Incentives for these investments have to be set by a supporting market and policy framework. In addition, the Swiss development is strongly influenced by the neighboring market dynamics, which set the relevant price levels and resulting imports/exports. The importance of those external drivers can already be observed today: the decreasing electricity prices in Central Europe (due to low coal and carbon prices coupled with increasing renewable generation) have put Swiss hydropower under pressure as profit margins crumbled and partly turned negative (CREST 2016).

As a consequence there is an ongoing debate in Switzerland how investment incentives can be ensured to achieve the envisioned renewable target and whether there is a need for capacity mechanisms. Within the debate renewable support (i.e. quota mechanisms, feed in premium) as well as more general investment support structures (i.e. capacity markets) are discussed (see, e.g., CREST (2017) regarding renewable support and SFOE (2016a) for a general system adequacy evaluation). From a system adequacy perspective also the Swiss network plays a crucial role in the debate. Being a central hub in the European electricity system Switzerland's own transmission system is influenced by developments in neighboring countries. The expected change in renewable and conventional generation, especially in Italy and Germany, will also lead to shifts in the import/export patterns on daily, seasonal and aggregated levels (Schlecht and Weigt, 2015).

The objective of this study is to combine those two dimensions. We analyze the potential impact different investment support schemes have on investments in Swiss generation capacities and evaluate whether a zonal re-configuration of the Swiss transmission system would provide any benefits. Given the insights of the first study we focus on the market supply side and don't model consumer choice. In contrast to the first study to objective of the second study is to calibrate the underlying model towards the current and expected Swiss market conditions. This allows us to provide specific policy recommendations with respect to renewable and investment support, policy interaction, and the impact of strategic company behavior on policy design.

3.2. Model

In order to assess the impact of different supply side policies we develop an aggregated Swiss investment model capturing the impact of neighboring countries and strategic company behavior.

3.2.1. Model Formulation

To allow strategic behavior we apply a partial equilibrium approach with two main market actors: strategic companies and an ISO managing the network and import/export trading. Figure 5 provides an overview on the model structure.

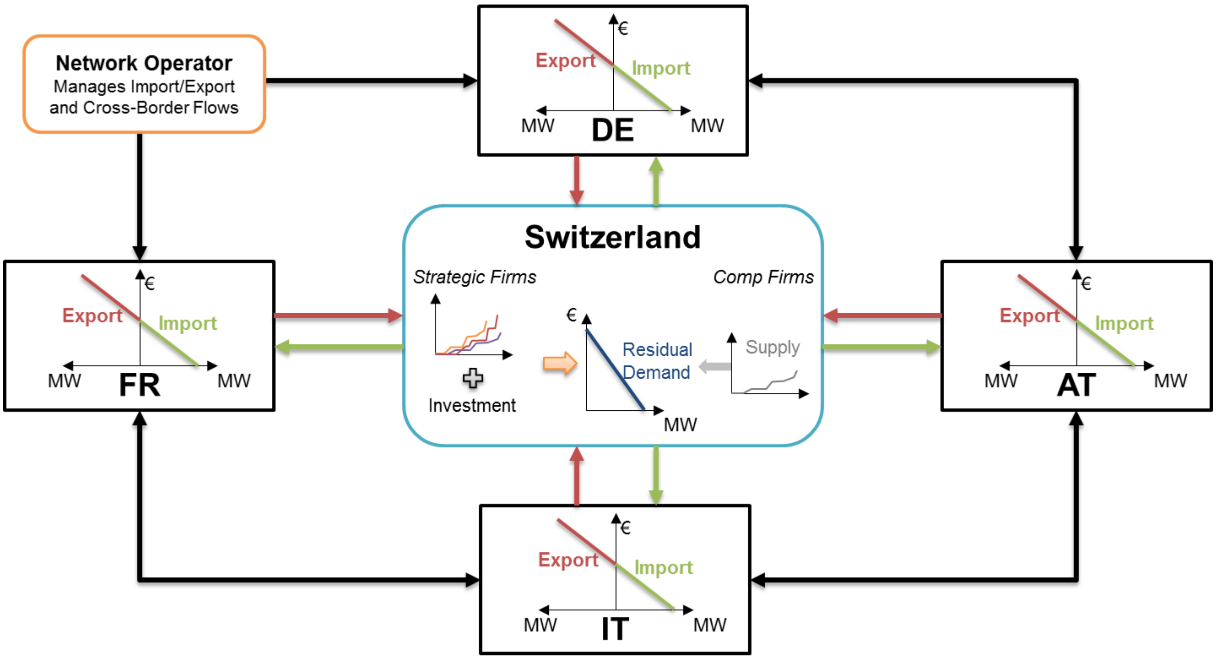

Figure 5: Model structure

Within Switzerland we assume that each strategic company *i* maximizes its own profit *Π* over a specified periodic time horizon given the demand relation *P(Q)* and their own generation costs c^{var} *Q* and investment opportunities c^{inv} Q^{new}:

$$\max \Pi_i = \sum_t \left[P_t \left(NI_t + Q_{i,t} + \sum_j Q_{j,t} \right) Q_{i,t} - c_{i,t}^{var} Q_{i,t} - \sum_t c_{i,t}^{inv} Q_{i,t}^{new} \right]$$

The demand function *P(Q)* represents the residual demand the strategic companies face after accounting for supply by competitive fringe firms within Switzerland. Following the classical Cournot assumption we account for the output of the strategic company (Q_i) and its strategic competitors (Q_j). In addition, the net import *NI* within Switzerland is an endogenous element of the demand relation.

The company is subject to a respective generation constraint:

$$Q_{i,t} \leq Q_{i,t}^{max}$$

Whereby the maximum capacity in a period can be increased by investments which are traced over time by the following balance function:

$$Q_{i,t}^{max} = Q_{i,t-1}^{max} + Q_{i,t}^{new} - Q_{i,t-LT}^{new}$$

After a predefined life time *LT* new investments are depreciated.

For each neighboring country we assume a perfect competitive import-export behavior based on local demand and supply conditions following a linear demand function logic:

$$P_n = a_n - b_n\, IMP_n$$

Note that the actual import-export *IMP* of a country can be positive (i.e. the country is importing electricity) or negative (i.e. the country is an exporter). Contrary, the demand relation in Switzerland only allows for positive demand *DEM*, but otherwise follows the same functional structure:

$$P = a - b\, DEM$$

Consequently, the market clearing condition for Switzerland looks as follows:

$$NI_{CH} + \sum_i Q_{i,t} = DEM$$

Whereas for neighboring countries the market clearing is defined as follows:

$$NI_n = IMP_n$$

The ISO manages the power flows in the grid given the net injections at each node of the stylized system ensuring that the resulting flows are within the lines capacity limits $flow^{max}$. We use a PTDF based formulation to directly transfer the net injections into power flows.

$$\max \Pi^{ISO} = \sum_n P_n\, NI_n$$

s.t.

$$\textstyle\sum_n NI_n = 0$$

$$\left|\textstyle\sum_n ptdf_{l,n} NI_n\right| \leq flow_l^{max}$$

The model is formulated as mixed complementarity problem and coded in GAMS.

3.2.2. Data

The stylized nature of the model aims to capture average, aggregated market conditions. The model time frame ranges from 2015 up to 2050 with five year steps. On the ***production*** side we rely on the European Energy Trends (EC, 2016) to provide capacity and fuel price estimates for the neighboring countries (see Table 1).

Swiss capacities are based on the 2015 values and are adjusted for subsequent periods with a linear depreciation for renewable capacities and the projected phase-out schedule for the nuclear capacities. For hydro we assume that the existing capacities remain available throughout the modeled period.[21] Extension of hydro capacities beyond the existing level and

[21] This translates into an implicit assumption that the needed retrofit investments will be carried out regardless of market price levels.

all other Swiss capacity additions are a result of endogenous investments. Investment costs are based on Schröder et al. (2013) representing average European cost assumptions (see Table 1). No specific adjustments for Swiss cost levels has been conducted. The investment costs therefore represent a lower benchmark for investment costs in Switzerland. As the model does not differentiate between Euro and CHF potential exchange-rate effects are not captured.

For conventional capacities the investment costs are constant regardless of added capacities. For renewable capacities we adjust the generic cost assumptions with potential estimates from Meteotest for each Swiss canton. This leads to an increasing costs function capturing the dependence of renewable capacities on weather conditions (i.e. sites with good conditions are taken first).

Table 1: Price [€/t] and Cost Assumptions [Variable in €/MWh, Investment in €/kW][22]

	Carbon Price	Variable Costs		Investment Costs						
		Coal	Gas	Hydro	Coal	Gas	Bio	Geo	Wind	Solar
2015	5	26	44	4000	1300	800	2424	3982	1269	950
2020	17	35	57	4000	1300	800	2350	3775	1240	750
2025	22	42	62	4000	1300	800	2278	3578	1210	675
2030	35	62	72	4000	1300	800	2209	3392	1182	600
2035	42	69	77	4000	1300	800	2141	3216	1154	555
2040	50	78	83	4000	1300	800	2076	3049	1127	472
2045	70	95	90	4000	1300	800	2013	2890	1101	448
2050	89	110	96	4000	1300	800	1951	2740	1075	425

On the ***demand*** side we aim to capture the dynamics within a year with four representative days (spring, summer, fall and winter). In addition, each day consists of representative hour blocks capturing morning, noon, afternoon, evening, and night conditions. The respective hourly load levels are based on the ENTSO-E and Swissgrid hourly demand profiles. We assume the historic demand profiles to remain valid for coming decades and distribute the respective yearly demand levels accordingly (for neighboring countries from the Energy Trends (EC, 2016) and for Switzerland from the scenario "Politisches Massnahmenpaket"[23] of Prognos (2013)).

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[22] The variable fuel cost level represent the assumed European price level to ensure consistency with the European Energy Trend data used for the neighboring countries. The investment level for hydro represent generic costs. As hydro is highly site-specific the model framework is not able to capture the diversity of the Swiss hydro structure. Consequently, the resulting investments are likely to underestimate the potential for upgrade of existing hydro capacities.

[23] Albeit the Energy Strategy 2050 aims for a demand path in line with scenario "Neue Energiepolitik" we have chosen the higher pathway of the scenario "Politisches Massnahmenpaket". Due to the elastic demand formulation the higher demand pathway ensures that the model results do not underestimate the investment needs.

Similar, we construct representative ***renewable production patterns*** by using historic injections as reference which are scaled up according to the installed renewable capacity. We do not account for different injection values following different investment locations. For Swiss hydro we use the values provided by the SFOE statistics on the 3rd Wednesday production profiles for March, June, September and December as reference (SFOE, 2016b). The resulting renewable patterns represent average injection conditions and therefore do not capture extreme situations.

Using the hourly reference demand levels, the installed conventional capacities and the hourly renewable production we construct the above described ***import-export behavior*** for neighboring countries by transferring the merit order into a linear supply curve and intersecting it with the reference demand level. For Switzerland we differentiate between a competitive fringe and the three largest companies acting strategic. To obtain a residual demand curve for the strategic companies we derive a linear demand function and subtract the supply by the competitive fringe for each hour. The linear demand function is based on the hourly reference demand level, a reference price, and a point elasticity.[24] The reference price is obtained by running the model with a fixed demand first and obtain the resulting Swiss market prices as reference. The elasticity is assumed to represent a medium term demand reaction at the reference point with a level of -0.5.

3.2.3. Network Representation and Zonal Configuration

Given the aggregated nature of the model the transmission framework is included via a simplified approach. We neglect inner country transmission and congestion issues and focus on cross-border tie lines. Based on the date provided by the ENTSOE adequacy report (ENTSOE, 2015) we derive the number of 220kV and 380kV cross-border lines for each modeled border. Using average values for resistance and capacity and assuming a line length equal to the distance between the country centers we construct aggregated tie lines. This simplified network is transferred into a respective PTDF matrix for the power flow calculation. For future periods we adjust the underlying network by including the planned extension of the Ten Year Network Development Plan 2016.

As we aim to assess the impact of a zonal reconfiguration of the Swiss electricity system on investment incentives we furthermore need to extend the above described aggregated network model. The zonal model formulation follows the basic structure with the main difference that Switzerland is split into two nodes. Demand and existing generation capacities

[24] Due to the assumed linearity of the demand function the demand elasticity is not constant across the demand space but a point elasticity ranging from elastic to inelastic levels.

are allocated to their respective zones and the Swiss inner country transmission lines connecting the two regions are treated as cross-border lines.

The main challenge is the definition of an appropriate zonal structure for Switzerland. Following the n-1 evaluations provided by Swissgrid (Figure 6) as well as estimates based on a full nodal representation (Figure 7) with the Swissmod model (Schlecht and Weigt, 2014) it is obvious that most of the critical line conditions are related to cross-border connections. Those are already represented by the simplified single zone representation.

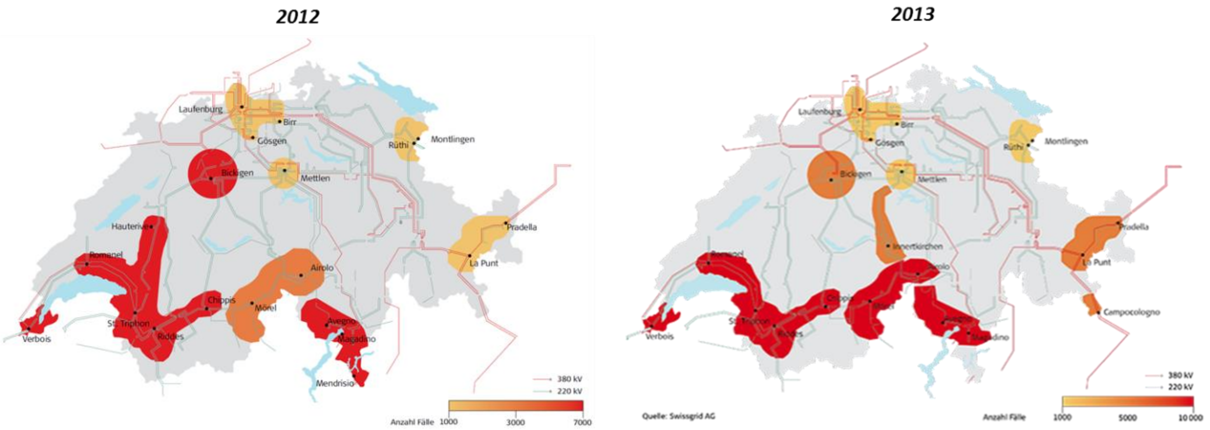

Figure 6: Swissgrid n-1 situations 2012 and 2013

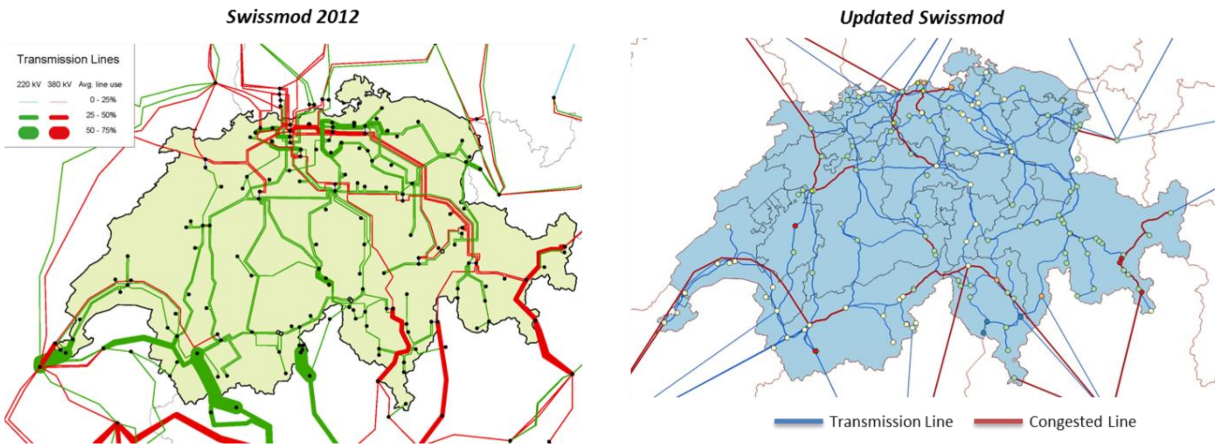

Figure 7: Swissmod line congestion

We observe a relatively high level of network congestion (i.e. high frequency of n-1 situations, high line loadings) in Southern Switzerland within Valais and Ticino. This is largely driven by the large scale hydro capacities and limited 220kV transmission lines: the local production surplus is exported to Italy and combined with the general North-South power flows towards Italy leads to high utilization levels of the respective low capacity 220kV lines; i.e. along the Mettlen-Airolo connection. In addition, the parallel North-South connection between

Bickigen and Chippis is among the projected network extensions of Swissgrid (Figure 8). Finally, a new connection along the lake of Neuchatel is planned to further strengthen the North-South connections.

Consequently, we decided to separate Switzerland into a Northern and Southern Zone using those three connections as cross-zonal border when defining which cantons are in the respective zones. Consequently, the Southern Zone covers the mountain regions from Grisson to Valais and the western cantons from Gevena to Fribourg and Neuchatel. The zones are clusters on a cantonal level, as we consider it unrealistic that a zonal split of Switzerland will strictly follow the network topology and split cantons into different zones.

The chosen zonal structure is to be seen as an exemplary representation. The focus of the analysis is to evaluate whether smaller market regions – accounting for more inner country network constraints – provide a benefit and/or require a different policy approach.

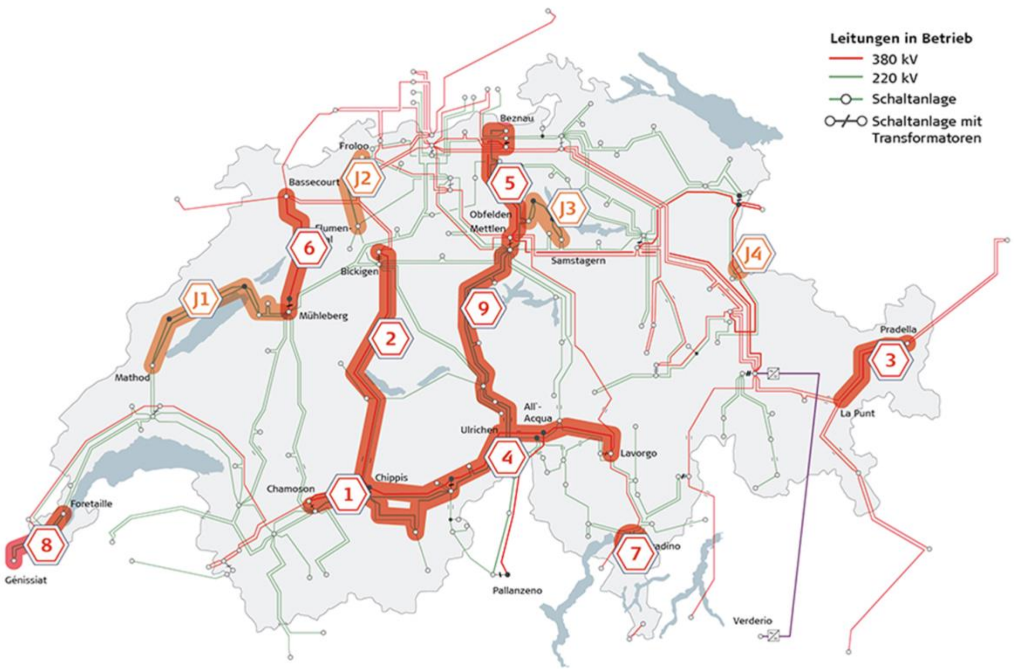

Figure 8: Swissgrid Net Extension Projects ‘Strategische Netz 2025’

3.3. Scenario Overview

To evaluate the future development of the Swiss electricity market we conduct a scenario analysis of different market designs. We analyze of four different general market outlets (*Energy Only Market, Capacity Market, Feed-In-Premium, Renewable Quota*) both for the *Single Zone* and *Two Zone* setup. In addition, we will analyze the *Interaction* of different support mechanisms. Furthermore, we derive a perfect competitive benchmark reference (PC) and the respective counterfactual with strategic company behavior (SB) for each scenario combination.

The market designs are differentiated as follows:

Energy Only Market: a framework without any renewable support mechanisms or capacity payments. The model follows the formulation presented above. Each producer aims at maximizing its profit by sales on the energy market. It therefore represents the current Swiss electricity wholesale market structure but assumes an abolishment of the current renewable support (KEV). The existing renewable capacities are gradually phased out within the next 20 years.

Capacity Market: a framework with a simplified capacity market in addition to the energy market ensuring a specific level of installed Swiss generation capacity. We assume a capacity target (cap^{target}) of 105% peak load that is auctioned via a yearly auction. The target is exemplary and aims to capture the usually logic imposed for capacity markets: ensuring sufficient local supply for critical load cases. The choice of 105% peak load is arbitrary and should not be interpreted as an optimal choice. Both the peak load reference level and the 5% security margin can be altered and will have a large impact on the underlying market results. The given framework will ensure that on average there is an oversupply of capacity within the market preventing the emergence of scarcity rents and potentially reducing market power incentives.

Each company's power plants are accounted for with their average yearly availability (av_i):

$$cap_t^{target} \leq \sum_i av_i Q_{i,t}^{max}$$

Due to the model structure each existing (including nuclear and hydro) and newly constructed power plant is automatically accounted for in the capacity target evaluation (i.e. no bidding process is modeled). The companies receive the resulting capacity market price (P^{cap})[25] regardless of their actual energy provision in the energy market for their respective generation capacity. Consequently each producer optimizes its profit taking both revenue streams into account:

$$\max \Pi_i = \sum_t \left[P_t \, Q_{i,t} + av_i P_t^{cap} Q_{i,t}^{max} - c_{i,t}^{var} Q_{i,t} - \sum_t c_{i,t}^{inv} Q_{i,t}^{new} \right]$$

Feed-In-Premium: a framework with a technology independent market premium on top of the energy price for renewable energy. The premium (*FIP*) is linearly decreasing from

[25] The market clearing price is defined as shadow price on the capacity target constraint; i.e. equivalent to a uniform market clearing price in the yearly capacity market auction.

40CHF/MWh in 2020 to 10CHF/MWh in 2035.[26] The premium is provided for the subset of renewable generation (Q^{RES}) accounting for wind, solar, biomass and geothermal but not for existing or new hydro units. Consequently each producer optimizes its profit taking into account that an additional return can be derived from producing with new renewable energies:

$$\max \Pi_i = \sum_t \left[P_t\, Q_{i,t} + FIP_t Q_{i,t}^{RES} - c_{i,t}^{var} Q_{i,t} - \sum_t c_{i,t}^{inv} Q_{i,t}^{new} \right]$$

As the premium is provided on top of the energy market price the assumed level leads to a total sales price for renewables of about 80 to 90 CHF/MWh given the underlying fuel and carbon price assumptions.

Renewable Quota: a framework with a technology independent renewable target and a respective tradeable permit market in addition to the energy provision. The needed renewable generation is defined via a quota (*qu*) of the total energy demand. For the quota hydro units and new renewable wind, solar, biomass and geothermal units are accounted.

$$qu_t\, DEM_t \le \sum_i Q_{i,t}^{RES} + Q_{i,t}^{Hydro}$$

The respective market clearing quota price (P^{Quota}) allows companies to derive additional profit for producing with renewable energies similar to the FIP setting:

$$\max \Pi_i = \sum_t \left[P_t\, Q_{i,t} + P_t^{Quota} \left(Q_{i,t}^{RES} + Q_{i,t}^{Hydro} \right) - c_{i,t}^{var} Q_{i,t} - \sum_t c_{i,t}^{inv} Q_{i,t}^{new} \right]$$

We assume a gradual increase of the quota level. The ES2050 aims for an increase in new renewable output to 11,4TWh and a total output of hydropower of 37,4TWh in 2035. As the quota is linked to the demand level which itself is an endogenous model outcome we use a stylized quota approach. Starting from todays 60% hydro share we increase the quota target in 5% steps per 5year to an 80% quota in 2035. Given the reference demand level in 2035 (based on the scenario “Politisches Massnahmenpaket”) this quota would lead to a total needed renewable output of ca. 50TWh, slightly above the envisioned ES2050 target. We assume a further increasing quota up to 90% in 2045 and 2050. We do not increase the needed share of renewable generation beyond 90% to allow the model some flexibility in its investment and import behavior and avoid potential high cost renewable capacity additions to ensure a 100% supply.

[26] A feed-in-tariff scheme like the KEV system has not been modeled. Due to the simplified and aggregated investment cost assumptions the resulting investment pattern would have been too arbitrary. The interplay between a tariff and strategic behavior as well as the impact on the Swiss market is discussed in the results section.

Given the stylized nature of the model and the policy approaches the scenario results are not to be taken as face value for quantitative system development forecasts. Also the numerical assumptions for the capacity target, premium levels and quota development are to be seen as indicative in nature and not meant to be a cost evaluation of the different approaches. Nevertheless, the different scenarios allow identifying driving factors and the impact of different market frameworks on investment incentives.

3.4. Single Zone Results

In a first set of scenarios we represent the Swiss market based on its current outlet; with a single uniform market price zone across Switzerland and within an integrated European market framework. We test the impact of the four different market designs under perfect competitive and strategic company behavior.

3.4.1. Result Overview

Table 2 summarizes the average price results for Switzerland for the different scenarios.[27] In all scenarios the energy market prices follow the generic fuel and carbon price trends set by the underlying European Energy Trend assumptions EC (2016). The resulting market prices are closely following the average variable coal generation costs with a slight markup due to the higher gas generation costs needed for peak situations. Only in the last modeled period – 2050 – the market price is slightly below coal levels, as the increased carbon price has pushed coal above gas. The differences of price developments across the different market design scenarios are limited. Due to its small size in comparison to the neighboring countries the potential for strategic price setting is rather limited albeit not completely restricted.

Taking 2030 as an example we can see that in the overall price level is going to increase from ca. 30 €/MWh to 69 €/MWh due to the assumed fuel price increase. In a competitive market setting the impact on wholesale prices of adding a capacity market (-1.3 €/MWh), FIP (+/-0 €/MWh), or Quota (-0.7€/MWh) are more or less negligible. In a setting with strategic Swiss suppliers the price level is slightly higher (70 €/MWh) and beside the quote mechanism (-0.8€/MWh) no support mechanism has an impact on wholesale prices. Overall the resulting price markups are below 5% and reduce to about 1% in all but the *Capacity Market* scenario.

However, the role of strategic behavior is pronounced on the capacity and quota markets as those are limited to Swiss provision. Taking 2030 as example again, we can see that with a quota mechanism a significant price level (ca. 550€/kW) will be needed once a large share

[27] A full overview on price and quantity results for each scenario are provided in the Appendix.

of the existing nuclear capacity is phased out. With strategic suppliers this price level is basically doubled. However, in all other periods the capacity price is zero under strategic behavior. Overall the average capacity price over all periods in the strategic setting is close to the competitive benchmark. Consequently, we cannot draw a general conclusion for the impact of strategic behavior on a Swiss capacity market. In case of a quota mechanism the competitive price level is about 60€/MWh in 2030 but 275€/MWh in case of strategic suppliers. Contrary to the capacity market, the quota price is significantly above the competitive benchmark in all periods.

The price results show that market power is no real concern on the energy markets as they are dominated by European market dynamics. However, Swiss-only markets for capacities or quotas can strongly be influenced by strategic behavior of large suppliers.

Table 2: Energy Market Prices, FIP and Quota [€/MWh], Capacity Market [€/kW]

	Average Spot Prices								Support Market Prices				
	EnOnly		CapMarket		FIP		Quota		Cap		FIP	Quota	
	PC	SB	PC	SB	PC	SB	PC	SB	PC	SB		PC	SB
2015	30.3	31.3	30.3	31.3	30.3	31.3	30.3	31.3				0.0	0.0
2020	40.6	42.5	40.6	42.5	40.6	42.5	40.6	42.1	175	0	40	0.0	18.6
2025	53.6	54.7	53.2	54.7	53.5	54.7	53.5	54.4	105	0	30	9.0	41.2
2030	69.3	69.9	68.0	69.9	69.3	69.9	68.6	69.1	543	1007	20	57.8	275.0
2035	81.0	81.8	77.3	81.7	80.0	81.8	79.9	80.4	88	0	10	0.0	53.3
2040	90.9	91.5	88.6	91.4	90.2	91.5	90.0	90.3	0	0		20.3	47.3
2045	101.0	101.5	98.0	101.2	100.3	101.5	99.9	100.0	79	0		20.6	67.7
2050	106.4	107.8	103.7	107.5	105.9	107.8	105.8	106.2	0	0		0.0	97.8

The underlying investment patterns are provided in Table 3 showing the newly constructed capacities per type for each five year block for the perfect competitive (PC) and strategic behavior (SB). In general, the results highlight that without further measures investments in Switzerland will only be conducted in renewable energies and not within the next two decades. Investment in hydropower does not occur in any scenario.[28] The results also highlight that investment in dispatch-able conventional generation only occurs if a specific support mechanism is implemented (capacity markets in this setting). This is in line with the general assumption that imports are the cheapest mean for Switzerland to replace its phased out nuclear generation (e.g. see discussion in CREST, 2017).

[28] As we do not account for depreciation of hydro capacities in Switzerland there is no account for needed retro-fitting investments. Furthermore, as we only account for generic hydro investment assumptions based on (rather expensive) new constructions we cannot capture the potential for upgrading existing hydro plants. The results for hydropower should therefore be interpreted as a model artifact.

Examining the breakdown of renewable investments into the different technologies (provided in the Appendix) for the competitive benchmark shows a preference within Switzerland for solar albeit occurring mostly in the later periods. Biomass is installed up to its assumed maximum capacity in each supportive market design. Finally, wind energy is installed in each market design but in rather low absolute levels (less than 1GW). Geothermal capacities are not installed in any scenario. In the strategic runs only the quota market design ensures significant investments into renewables, mostly biomass and solar. All other cases see only minor additions in late periods. The investment drop in 2040 in the capacity and FIP market framework in renewable generation is due to biomass investments. Given the assumed potential and cost structures, the model optimization leads to large biomass investments in 2035 reaching the biomass capacity limit to either benefit from the capacity market price or last period with a FIP.

The resulting investment patterns in conventional generation furthermore highlights that even before the full phase-out of nuclear power plant significant capacity additions are needed to ensure the imposed capacity target. Compared to the Prognos (2013) variation C the resulting yearly fossil generation levels are comparable (i.e. about 22TWh in 2040) but decline in later periods (i.e. 14TWh in 2050) due to increased renewable shares.

Table 3: Capacity Additions per Period [MW][29]

	Renewable Capacities								**Gas**	
	EnOnly		CapMarket		FIP		Quota		CapMarket	
	PC	SB	PC	SB	PC	SB	PC	SB	PC	SB
2015								10		
2020								231	2'736	2'736
2025			170		91		326	566	610	664
2030	60		269		148		990	864	1'026	1'110
2035	279		2'006	50	1'950		1'154	1'619	343	1'535
2040	222		1'649	81	149		3'031	5'151		159
2045	1'080	24	8'320	126	813	24	3'534	1'417	1'407	2'888
2050	7'662	39	7'878	345	7'254	39	2'486	1'387		729

3.4.2. Comparison and Interpretation

Comparing the results of the market design cases provides some general insights on the Swiss market dynamics and shows clear effects of strategic company behavior.

First, a simple *Capacity Market* framework leads to a replacement of nuclear capacities with natural gas fired generation. This is also the only market design leading to investments in

[29] Detailed results on technology level for the single zones scenarios are provided in the Annex.

conventional technologies within all simulations. Under perfect competitive assumptions a total of about 5GW of gas capacities are constructed until 2035. In the following years the investments shift towards renewable generation due to further costs reduction for wind and solar generation. With strategic companies the newly constructed capacities are not used for generation. Consequently, Switzerland has an import level of ca 25TWh per year after the nuclear phase out despite having about 6GW of natural gas capacities (see Appendix for details). This is a direct result of the non-existing linkage between capacity payments and energy provision. With the capacity market, companies have incentives to build capacities. But due to strategic behavior, there is a strong incentive to withhold these capacities from the market in order to avoid price reductions on the Swiss market due to oversupply and reap additional profits.[30] Of course, this is a rather extreme case, but it shows clearly that capacity markets will not necessarily induce a higher domestic supply. The results are in line with the debate on capacity market design and the importance of implementing not only payments for capacity provision but also setting incentives to provide this capacity in times of shortage (see Batlle and Rodilla, 2010, Spees et al. 2013, Cramton and Ockenfels, 2013 and Betz et al. 2015 for more details on capacity market design).

Second, an undifferentiated *Feed-In-Premium* scheme with modest mark-ups will not suffice to attain large-scale investments in renewables. Naturally, this result depends strongly on the underlying investment cost assumptions, the (arbitrarily) chosen dynamic of the FIP and the assumptions on general fuel costs. A higher premium or lower cost assumptions will induce more investments than in the chosen outlet. Similar higher fuel or carbon prices general increase the incentives to invest into renewables which adds to the effect of a FIP. Despite the large impact of numerical assumptions, the results still highlight an important caveat of FIPs: if a specific quantity target is to be achieved (i.e. like the 11,4TWh of the ES2050) a careful tailoring of the premium level will be needed. Given the large uncertainties on future market developments such a tailoring is unlikely with a simple fixed market premium. Hybrid designs coupling price and quantity elements are a more promising approach (see also CREST, 2017). For example, the level of the premium could be linked to the installed capacity levels and their accordance with the ES2050 targets. If the installed capacity exceeds the project pathway, the premium is reduced, and if investments are too low, the premium is increased.

Under strategic behavior the premium has no investment impact at all. This is caused by the revenue impact of added renewable generation. Although renewables provide additional

[30] This is a result of the model formulation with competitive import-export and domestic market power. The Swiss companies therefore account for the Swiss demand dynamic but do not fully account for the reaction on imports. The behavior of Swiss producers therefore is more pronounced in terms of capacity withholding.

profit due to the premium, they also reduce the obtainable revenue from all other producing power plants by reducing energy market prices due to the merit order effect. If this trade-off is negative, as in the simulated cases, strategic acting companies withhold investments in renewables. The effect is especially pronounced when companies have mostly base load units as even small market price reductions can add up to large total revenue reductions that would need to be compensated by increased revenue from the supported renewable output.[31]

Finally, a *Quota Mechanism* ensures that sufficient new renewable capacities are constructed as the quota directly targets renewables. Strategic companies have a large impact on the resulting certificate prices but investments in renewable capitates reach similar levels and comparable dynamics as in a perfect competitive setting. The resulting strategic price markup on the energy market is also the lowest in this scenario. As the quota mechanism is linked to output (contrary to the capacity mechanisms which is only linked to capacity) the strategic companies are forced to produce with their renewable capacities to fulfill the quota target. Given that the quota market is limited to Switzerland only the three strategic firms have sufficient market power to influence the resulting prices as European competition has no direct impact on the Swiss quota.

Albeit not directly modeled the scenarios also allow an assessment of a *Feed-In-Tariff* scheme. The actual investment pattern will solely be driven by the level of the tariff and consequently can lead to under- or overachieving of the envisioned ES2050 targets. The impact on the overall price level will remain rather modest; e.g., comparable to the price level of the quota scenario in case of investments in line with the ES2050. As additional renewable capacities will reduce the obtainable rent of strategic companies on the energy market they are likely not incentivized to use the scheme for investment similar as in the feed-in-premium case. However, as is evident from the KEV scheme, one can expect a large number of smaller providers using the scheme to finance investments.

In summary, the results show that without policy intervention, no additional investments in domestic production capacity are likely in the near future with the cost and price assumptions used in the model. Thus if such investments are desired, there is a need for national schemes, such as capacity markets or support for renewables. In addition, such tools have to be carefully designed to avoid potential abuse by larger actors.[32]

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[31] For example a 1CHF/MWh price reduction would reduce the income from a 1GW nuclear power plant with 90% availability by ca. 8Mio CHF per year. Assuming an average availability of solar of 15% this translates into a total of ca. 6GW needed solar capacity if a markup of 10CHF/MWh could be obtained.

[32] As the scenarios results strongly depend on the underlying assumptions, we perform a sensitivity analysis with respect to renewable investment costs. Assuming either a 10% or 20% reduction in cost levels leads to a forward shift of renewable investments of five to ten years at most. However, the overall

3.5. Two Zones Results

We now turn to the second question of our study: whether a zonal reconfiguration of the Swiss market has an impact on investment incentives. Splitting up Switzerland in a Northern and Southern trading zone can account for the respective differences in the demand-generation structure of those regions and the underlying network topology.

3.5.1. General Impact of a Zonal Split

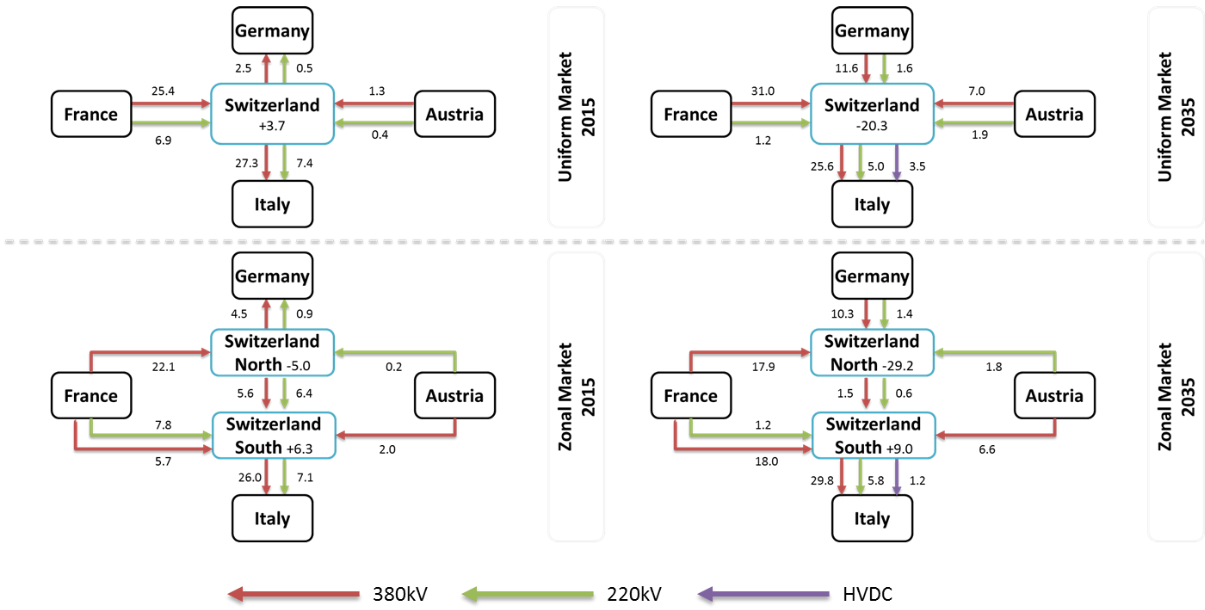
Figure 9 highlights the resulting power flow patterns in the *Energy Only Market* framework for the single and two-zone model. In aggregate the zones provide similar results as in a uniform approach for both the yearly Swiss import balance and the respective cross-border exchanges. The figure also highlights the expected change in case of a full nuclear phase-out in 2035. Given that in the *Energy Only Market* framework we only observe minimal investments up to 2035 the nuclear capacities are compensated by a significant increase in imports. In total Switzerland becomes import dependent, but the effect is more differentiated in a zonal setup. Northern Switzerland, place of all nuclear stations and most of the large demand centers, will become import dependent with about 70% of local demand covered by imports. Southern Switzerland, home to large scale hydro capacities, will remain a net exporter. France will remain an important exporter but also Germany and Austria will increase their supply to Switzerland. At the same time Italy will remain dependent on imports via Switzerland. Thus the increased need for imports to cover Swiss demand will be provided on top of the prevailing flows towards Italy. In the zonal model the separated structure highlights that those continued flows are mostly stemming from France and Austria, whereas German supply is utilized to cover demand in Northern Switzerland.

The impact of a zonal configuration on energy market prices is basically negligible. On average the differences are less than 2€/MWh across the different years. This result again highlights the embeddedness of the Swiss market in the European framework: the majority of the Swiss price level is defined by external conditions. The similar price levels in Northern and Southern Switzerland also highlight that on average the two zones have sufficient transmission capacity.[33] Congestion will remain an issue along borders though, slowly moving from the Southern borders (Southern Switzerland and France and Italy) towards Northern borders (Northern Switzerland and France as well as France and Germany).

investment patterns and distribution across technologies remains unaltered. Detailed results on the sensitivities can be provided upon request.

[33] Note that the network data for 2020 and beyond accounts for the projected extensions of the TYNDP including the Swissgrid extension projects.

Figure 9: Aggregated Cross-Border Exchanges and Balance, Energy Only [TWh]



3.5.2. Impact of Different Market Designs with Uniform Targets

In a first set of scenarios we focus on a pure zonal split on the energy market in Switzerland but not in policy targets. Using the same uniform Swiss wide capacity target, FIPs and quota levels as in the single zone scenarios we can evaluate whether a zonal separation would have different impacts on investment incentives due to different energy market price levels.

Similar to the general impact of a zonal split in the energy only setup described above the impact on energy market prices for the different market designs is limited (see the Appendix for a detailed comparison of the single and zonal results). However, the impact on capacity and quota prices is more pronounced (Table 4).

Table 4: Single vs Two Zones, Quota [€/MWh], Capacity Market [€/kW] Prices

	Single Zone				Two Zones			
	Cap		Quota		Cap		Quota	
	PC	SB	PC	SB	PC	SB	PC	SB
2015			0.0	0.0			0	67.7
2020	175	0	0.0	18.6	301	0	0	105.9
2025	105	0	9.0	41.2	104	326	0	151.2
2030	543	1007	57.8	275.0	350	690	21.6	229.1
2035	88	0	0.0	53.3	139	0	70.2	95.6
2040	0	0	20.3	47.3	0	0	25.2	47.2
2045	79	0	20.6	67.7	200	0	18.4	82.2
2050	0	0	0.0	97.8	0	326	0	108.7

In the zonal setup the prices are in general higher. For the competitive scenarios the average capacity price is 155€/kW in the zonal setup compared to 140€/kW in the uniform setting. Similar, the average quota price is 19€/MWh compared to 15€/MWh. In the strategic setting the markups increase; for the capacity price to 190 vs. 145€/kW and 110 vs 75 €/MWh for the quota. For the quota prices the result is likely an artifact of the model formulation.[34] For the capacity price the difference between both configurations is puzzling. In both the competitive and strategic case about 1GW of additional generation capacity is constructed in the zonal setup (see below for details). A potential explanation could be the different import/export patterns in neighboring countries coupled with the changed production pattern in Switzerland providing incentives for additional capacities. However, no clear-cut driver can be identified.

Analyzing the impact of the zonal reconfiguration on the investment patterns we can also observe a high convergence between the single and two-zone setup. Table 5 shows the renewable investments for the competitive benchmark scenarios. For the Energy Only Market framework we can observe slightly earlier investments skewed towards the Southern zone (due to good solar potential). However, the cumulative investments until 2050 remains in both cases close to 9GW. A very similar structure is observed in the Feed-In-Premium scenario. As in the single zone setup, the premium does only induce a slight shift in the timing of renewable investments, but the overall results are very close to the energy only setup.

[34] The Swiss demand function is derived by constructing the residual after the fringe supply. Also for the competitive case this design is considered as we assume that the strategic companies behave competitively while still being subject to the same residual demand function as in the strategic setting. We impose a lowest residual demand level of ‘0’ for feasibility reasons, which is not relevant for the single zonal approach. However, in the two zone setting the Southern Zone shows a negative residual demand for several hours during the summer as the local fringe supply is higher than the actual demand in Southern Switzerland. As the residual demand caps this effect at ‘0’ we have a slightly higher overall demand level in the two-zone simulations. As the quota mechanism is coupled to the demand level this translates into a higher need for renewable capacities with respective higher quota price requirements.

Implementing a single *Capacity Market* framework while splitting the energy market in two zones leads to a slight reallocation of renewable investment from 2035 onwards. Again in total about 20GW of renewable capacities are constructed like in the single zone setup. However, the two zones allow to identify where those investments are occurring. The majority are PV capacities which are firstly constructed in the Southern Zone (8.3GW starting form 2040 on) and followed by PV in the Northern Zone (9.3GW starting from 2045 on). For the conventional capacities the zonal configuration also leads to a similar pattern but a higher total of investments.

The largest deviation between the single and two-zone setup is observable in the *Quota* framework. While we also see a gradual increase of renewable investments in line with the increasing quota we observe a higher total investment level in the two-zone setup. Similar to the quota price deviation above we attribute this result to the differences in the overall needed RES amount in the two setups. Consequently, we consider the results of both model runs to be rather similar in their investment incentive structure with a large focus on PV installations.

Table 5: Renewable Capacity Additions, Perfect Competition [MW][35]

	EnOnly			CapMarket			FIP			Quota		
	Single	N	S	Single	N	S	Single	N	S	Single	N	S
2015									15			
2020						119			173			141
2025			69	170		130	91		62	326	399	1'033
2030	60		169	269	42	131	148		62	990	172	196
2035	279	22	764	2'006	114	160	1'950	47	70	1'154	774	1'005
2040	222	101	102	1'649	105	2'599	149	92	128	3'031		3'402
2045	1'080	112	2'142	8'320	6'003	4'158	813	109	2'434	3'534	1'898	1'871
2050	7'662	2'101	3'376	7'878	4'465	2'940	7'254	2'427	3'489	2'486	3'909	2'595

Turning to the model runs with strategic company behavior (Table 6) the Energy Only Market and Feed-In-Premium scenarios show the same 'no investment' results in the two-zone setup as in the single zone simulations. For the Capacity Market framework, we observe a large investment in renewables for 2035 in the northern zone in the two zone setup (consisting mostly of biomass capacities). The total amount of investments in conventional generation as well as the general pattern over the years are similar in both configurations.

For the *Quota* framework we observe an interesting effect. Contrary to the perfect competitive benchmark the investments are focused on the northern zone even though costs are higher there. Given that this is a result of the strategic possibilities of the larger companies

[35] Detailed results on technology level for the two zones scenarios are provided in the Annex.

it must be linked to incentives imposed by the quota, by their existing capacities, and/or by potential changes in flow patterns. Given that all nuclear power plants are located in the northern zone the resulting merit order effect of new renewable generation should actually favor investments in the southern zone. Consequently, it is unclear which effect leads to the observed investment pattern.

Table 6: Renewable Capacity Additions, Strategic Company Behavior [MW]

	EnOnly			**CapMarket**			**FIP**			**Quota**		
	Single	N	S	Single	N	S	Single	N	S	Single	N	S
2015										10	528	299
2020										231	1013	33
2025						1				566	179	362
2030						32		1	3	864	2558	1
2035		26	2	50	1'020	29		112	8	1'619	4285	225
2040			13	81	53	38			6	5'151	2643	202
2045	24		19	126	79	33	24		16	1'417	3905	143
2050	39		13	345	661	28	39		12	1'387	1182	168

3.5.3. Impact of Different Market Designs with Zonal Targets

So far only the energy market has been split in zones whereas the policy measures have remained on an aggregate Swiss wide level. Given the underlying logic of both the capacity target (defined by peak load) and the quota mechanism (a share of total demand) an implementation on zonal level would be possible. In two additional runs we analyze the impact zonal capacity and quota mechanisms would induce on Swiss investments.

Given the fact that the Southern Zone has a general supply surplus due to its large hydro capacities both the capacity and quota target are more relevant for Northern Switzerland. Table 7 highlights this effect for the capacity market scenarios. In case we impose a separate peak load target for each zone, investments in Southern Switzerland greatly reduce. They are basically limited to those that are based on energy market revenues.

Table 7: Comparison Single vs. Zonal Capacity Market, Investments [MW]

	Perfect Competition								Strategic Company Behavior							
	Single				Zonal				Single				Zonal			
	RES		Gas		RES		Gas									
	N	S	N	S	N	S	N	S	N	S	N	S	N	S	N	S
2015											51	816			258	
2020		119	1'386	1'618			3'098					2'487			2'839	
2025		130	623			99	683			1	339	13			683	
2030	42	131	1'056		55	163	1'045			32	1'100			18	1'063	
2035	114	160		1'464	1'074	191	740		1'020	29	1'079	62	1'021	54	757	112
2040	105	2'599			75	94	100		53	38	1'300	2'131	53	26	366	49
2045	6'003	4'158		1'043	3'915	904	2'562		79	33			79	27	2'943	55
2050	4'465	2'940			7'711	2'879			661	28	127	292	657	24	695	57

For the Quota, a zonal split leads to a similar effect (

Table 8) in case of a competitive market setting. Investments are focused on Northern Switzerland to keep the respective quota whereas Southern Switzerland fulfills the same quota with the existing hydro capacities. Again, investments in the southern zone are induced by the energy market. Given that the quota mechanism includes the hydro share and is designed with the total Swiss hydro in mind, the resulting quota levels for Northern Switzerland are way above the existing hydro capacity and vice versa in the South. The resulting peak in renewable investments in 2015 shows this effect as a large initial increase in available renewables is needed to achieve the 60% share in Northern Switzerland. Afterwards the investment pattern is more in line with the single zone investments.

Given that the majority of renewable investments across all scenarios are solar capacities, as zonal north-south split would actually lead to suboptimal investments. In case of a zonal quota market therefore respective adjustments to the zonal quotas in line with local availabilities and potentials need to be conducted.

Overall the results of the zonal policy designs highlight the problems when designing localized policy requirements. Given the structural differences between the import dependent northern zone and the hydro dominated southern zone a too general design approach is likely to lead to distortions. However, tailored and highly differentiated regional policies are likely to run into justification problems during the political process as they could be perceived as unfair.

Table 8: Renewable investment Single vs. Zonal Quota Mechanism [MW]

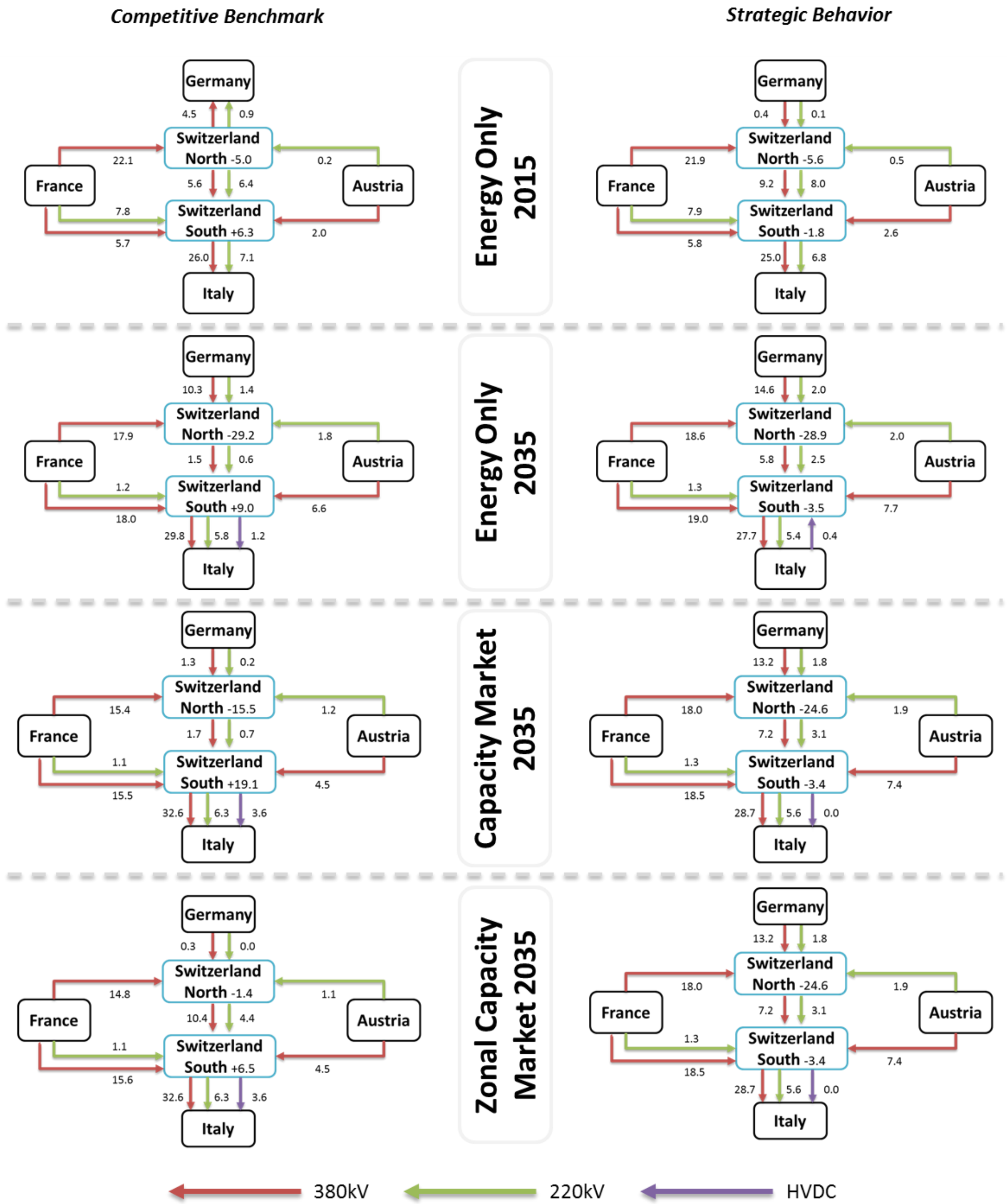
	Perfect Competition				Strategic Company Behavior			
	Single		Zonal		Single		Zonal	
	N	S	N	S	N	S	N	S
2015			5565		528	299	5296	0
2020		141	1614		1013	33	1506	0
2025	399	1'033	1427	29	179	362	1578	0
2030	172	196	1822	204	2558	1	1825	0
2035	774	1'005	2198	224	4285	225	2170	0
2040		3'402	12912	1022	2643	202	8333	7
2045	1'898	1'871	1614		3905	143	3385	47
2050	3'909	2'595	14		1182	168	1994	47

3.5.4. Role of Regional Policy Approaches on Network and Import Dynamics

Beside the price and investment impacts a zonal reconfiguration can have potential impacts on the Swiss transmission position and market dynamics over the year. Thus, we now turn to assess the feedback of policy choice on the network.

In general, the nuclear phase-out will alter the Swiss generation structure until 2035 by withdrawing ca. 25TWh from the system. Without a capacity or quota mechanism no further investments will compensate the phase-out. Consequently, Northern Switzerland will become import dependent whereas Southern Switzerland remains a net exporter of hydro-based generation (Figure 10, left panel). Implementing a capacity market will induce investments into gas fired generation to ensure sufficient local production capacity and greatly reduce imports from Germany. Without a zonal definition of targets, the investments will be based on zonal energy prices, local costs structures and network restrictions. In our simplified model the respective investments are split between the Northern and Southern zone leading to an even greater export surplus in South Switzerland.

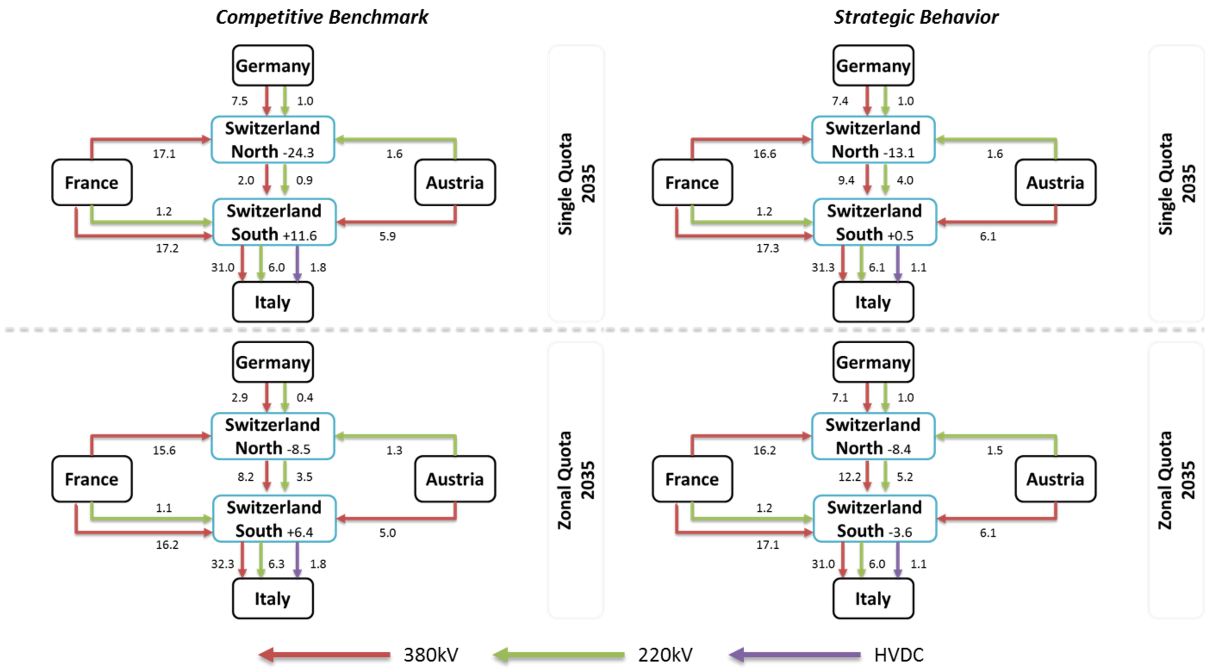
Figure 10: Aggregated Cross-Border Exchanges and Balance, Capacity Market [TWh]



Imposing zonal capacity targets shifts those investments towards Northern Switzerland. As a result, the inner Swiss power flows greatly increase towards the South. This contradictory result is an effect of the underlying European import/export flow pattern. Regardless of the investment decision in Switzerland, the country will remain a transit hub from France and Austria towards Italy. Changes on the net-import position of the Swiss zones only alter the power flows directed towards these zones but not the flows directed towards Italy. Consequently, a lower net-import in Northern Switzerland due to local generation capacities allows transferring the imports from France towards Italy via Southern Switzerland compensating for the missing exports from Southern Switzerland to Italy.

A similar trend can be observed in case of strategic company behavior in Switzerland (Figure 10, right panel). Exports towards Italy are basically unaltered by the market design decision in Switzerland. However, compared to the competitive benchmark the results again highlight the missing link between capacity and energy. Albeit the capacity market in both the uniform and zonal setup induced significant investments in gas fired generation those capacities are little used. As a results Northern Switzerland remains import dependent, regardless of zonal targets.

Figure 11: Aggregated Cross-Border Exchanges and Balance, Quota Markets [TWh]



Under the quota mechanism the differentiation between the single and zonal approach is even more pronounced for 2035 (Figure 11). For the competitive benchmark, most of the investments would occur in Southern Switzerland due to its favorable renewable conditions. In turn the North would be strongly import dependent while the South would become an even larger net exporter. Under a zonal quota regime, the northern dependence is greatly reduced whereas the South keeps a similar net export level like 2015. Under strategic company behavior renewable investments are already focused on Northern Switzerland in the single quota regime. Consequently, the resulting import dependence in the North is also less pronounced. Until 2035 the South even becomes slightly import dependent similar to the capacity market results.

3.6. Policy Interaction

For the last analysis we return to the single zone setup and evaluate a potential policy interaction: renewable support with simultaneous capacity targets. For this assessment we combine the capacity market design with the FIP and quota framework respectively. The capacity market ensures that sufficient power plant capacity is available in Switzerland while the renewable support mechanisms aim at providing incentives for investments into renewable capacities.

The Swiss energy market price level is basically not impacted by adding a FIP or quota mechanism to a capacity market framework. In case of a perfect competitive setting the price level is similar to a single capacity market framework. In case of strategic company behavior, the price is equal to a single capacity market framework if a FIP is added and similar to the single quota framework price level in case a quota is added (see Appendix for details).

Table 9 provides the prices on the capacity and quota markets for the different policy combinations. The FIP has no impact on the resulting capacity market prices. In case of adding a quota on top the largest impact can be observed in the resulting quota prices. As a share of the needed investment cost coverage for renewables can already be covered by the capacity market the quota price level is lower.

Table 9: Support Market Prices, Quota [€/MWh], Capacity Market [€/kW]

	Perfect Competition					**Strategic Company Behavior**				
	Single		Cap+FIP	CAP+ Quota		Single		Cap+FIP	CAP+ Quota	
	Cap	Quota	Cap	CAP	Quota	Cap	Quota	Cap	CAP	Quota
2015		0.0	0	0	0.0		0.0	0	0	0.0
2020	175	0.0	166	131	0.0	0	18.6	0	0	16.4
2025	105	9.0	105	105	0.0	0	41.2	0	0	33.9
2030	543	57.8	552	587	40.2	1007	275.0	1007	1007	183.6
2035	88	0.0	88	88	0.0	0	53.3	0	0	53.6
2040	0	20.3	0	0	15.4	0	47.3	0	0	45.1
2045	79	20.6	70	35	0.0	0	67.7	0	0	65.4
2050	0	0.0	0	0	0.0	0	97.8	0	0	80.2

Turning to the impact on investment dynamics the negligible impact of the FIP on top of a capacity market is confirmed for both the perfect competitive and strategic setting. Renewable (Table 10) and conventional investments (Table 11) are basically similar to a pure capacity market framework. Given the rather limited investment incentives provided by the single FIP framework the result is not surprising. This again highlights the challenge when deciding about the premium level.

The results for combing capacity and quota mechanisms show significant differences between the perfect competitive and strategic setting. In the later the resulting renewable investments are similar to a single quota framework while the accompanying conventional investments are slightly below the single capacity market results. The quota forces the companies to provide the specified level of renewable generation which in turn lowers the need for additional conventional capacities. However, as is evident from the resulting prices (Table 9) this only leads to a reduction of the quota price and not to reductions on the capacity market price level.

Under perfect competitive conditions the resulting investment dynamic is less clear cut. In the periods up to 2040 renewable investments are rather similar to a single quota framework and conventional extensions similar to a single capacity market framework. However, in the last two periods the renewable investments significantly increase compared to a single quota approach while at the same time also the conventional investment is significantly above the single capacity market framework. In this last modelled decade, the quota level does impose a moderate investment level for renewables (covering the remaining demand gaps with imports) whereas the capacity market requires a higher level of installed capacity in Switzerland. The resulting investments in a combined setup are now a mix of those two structures that provides a lower support level (both the capacity and quota prices are lower, see Table 9).

Albeit not directly modeled the results again allow an estimation how the combination of a capacity market with a feed-in tariff structure like the KEV would behave. As the FIT would incentivize renewable investments it would accordingly lower the need for additional renewable or conventional investments to fulfill the capacity target. Under strategic behavior one could assume the resulting market patterns could be similar to the combined capacity and quota framework. The additional renewables lower conventional investments but have limited impact on energy market prices (due to the large influence of European market dynamics) and the capacity price (due to market power potential by the strategic firms). Under perfect competitive conditions the picture may again be more complex as the additional capacities impact the capacity market price thereby creating feedback effects on the overall investment pattern.

Table 10: Renewable Investments [MW][36]

	Perfect Competition					Strategic Company Behavior				
	Cap	FIP	Quota	Cap+ FIP	CAP+ Quota	Cap	FIP	Quota	Cap+ FIP	CAP+ Quota
2015				91	0			10	0	38
2020				379	190			231	0	291
2025	170	91	326	63	327			566	28	577
2030	269	148	990	51	896			864	21	776
2035	2'006	1'950	1'154	1'877	1'172	50		1'619	24	1'597
2040	1'649	149	3'031	1'650	3'161	81		5'151	57	5'466
2045	8'320	813	3'534	8'683	4'615	126	24	1'417	118	1'393
2050	7'878	7'254	2'486	8'133	7'901	345	39	1'387	370	1'343

Table 11: Gas Investments [MW]

	Perfect Competition			Strategic Company Behavior		
	Cap	Cap+FIP	CAP+Quota	Cap	Cap+FIP	CAP+Quota
2015						
2020	2'736	2'588	2'676	2'736	2'736	2'633
2025	610	644	561	664	655	483
2030	1'026	1'094	628	1'110	1'103	779
2035	343	384	806	1'535	1'543	559
2040				159	167	
2045	1'407	1'282	1'777	2'888	2'891	1'958
2050				729	722	562

Summarizing, the two interaction cases highlight the general problems when combing multiple instruments within one market: First, one instrument can be more restrictive than the other (i.e. the capacity target requires more investments than a FIP will induce) making the second instrument obsolete (see also Abrell and Weigt 2008 for a related example).

Second, the combination can impose complex changes in incentive structures which in turn depend on the level of competiveness of the market. Consequently, the resulting effects can differ greatly between highly competitive and oligopolistic markets. This requires again a sophisticated tailoring of the two instruments to ensure that the instruments achieve the desired environmental targets; but it also allows to use those instruments to address deviations imposed by market power abuse.

Finally, the results also highlight the difference between a balanced supply-demand schedule over the year and actual sufficient supply capacity to cover demand throughout the year. In the combined quota and capacity market framework a significant amount of renewables is installed in Switzerland. However, there is still the need for additional dispatch-

[36] Detailed results on technology level for the combined scenarios are provided in the Annex.

able gas stations to satisfy the capacity market requirement and ensure sufficient local generation capacity in relation to the peak demand levels.

3.7. Conclusion and Policy Recommendations

The objective of this study has been to analyze the potential impact different support schemes have on investments in Swiss generation capacities under different transmission regimes. Using a market model capturing strategic company behavior in Switzerland with a simplified network allowing a zonal representation we have analyzed the impact of a capacity market framework, a feed-in premium and a green quota regime. Although, the underlying model assumptions and simplifications pose limitations on the transferability of the results into precise forecasts, the simulations still allow us to identify general trends and drivers.

Regarding the different policy approaches and their impact on companies' investment incentives we have identified four main insights:

First, under the assumptions taken, without any additional support mechanism, Switzerland will not immediately replace the phased-out nuclear capacities but rely on imports. Renewable capacities are added gradually later on following increasing electricity market prices and falling investment costs.

Second, to achieve the objective of the Energy Strategy 2050 with regard to renewables, a support mechanism is required. Relying on price-based mechanisms (feed-in tariffs or premiums) will require a well-tailored design of the financial incentives, because market dynamics and investment costs vary over time. Especially if a premium is used, the general market price development becomes a crucial factor for investment incentives. The premium level would need to be coupled to some underlying market and cost indicator to allow an automatic adjustment. A quota mechanism is more promising to obtain the desired ES 2050 targets, as it ensures obtaining the intended quantity targets. However, the absolute support level is uncertain and the increased risk for investors may lead to higher financial requirements. An alternative approach could the coupling of price- and quantity-based elements (hybrid instruments); for example the premium level could be coupled to quantity targets and increased/decreased accordingly. These results are in line with the discussion in CREST (2017) on the future of Swiss renewable support policies.

Third, the interaction of different policies can lead to complex market structures and complicate the design of the respective policies. Although domestic capacity availability (addressed via a capacity mechanism) and renewable support (either via price or quantity approaches) have different objectives, they nevertheless impact the same actors and have cross effects on investment incentives. Depending on the desired political targets one dimension may dominate the other and make additional policies superfluous (i.e. the quota is so high that the desired level of domestic generation capacity is already available). When multiple policies are binding, the interaction may result in hard to forecast effects or even reversal of intended incentive structures (see also the 'green serves the dirtiest' debate following Böhringer and Rosendahl (2010) for a related aspect when combining renewable and climate policies). Also, the results of the different policy options and combinations show that, if the support is focused on renewable energy production, imports are still needed during low renewable infeed situations. Thus, if in addition also specific domestic production targets are to be achieved, a specific instrument will be needed on top of renewable support.

Fourth, the impact of strategic behavior needs to be taken into account when designing policy approaches. This is especially relevant for a capacity mechanism, as a suboptimal design focusing solely on capacity and neglecting energy provision facilitates a strategic exploitation (e.g. see Betz et al. (2015) for different capacity market design aspects). This issue is less prominent under a quota mechanism, because, by design, a quota market is focused on delivered energy and thereby also ensures significant local generation under strategic behavior of Swiss actors. However, the aspects of competitiveness also play an important role when combining multiple policies making it more complex to forecast the impact of policies. Given the large impact of Europe on Swiss wholesale prices the role of strategic influence is most prominent for Swiss-only elements like capacity market or quota prices levels.

Regarding the impact of transmission and zonal structures the model results allow two main conclusions:

First, regardless of the chosen policy framework or zonal configuration, Switzerland will remain a transit hub for exports towards Italy. In all future scenarios the amount of exports towards Italy remains relatively stable. This highlights that the existing and projected network extensions are sufficient to cover changes within Switzerland without altering the Swiss hub nature within Europe. A zonal split into a Northern and Southern Zone does not provide additional benefits.

Second, the stable import/export structure also highlights a related aspect of the Swiss market: It is largely driven by European market conditions. The energy market prices react only marginally to Swiss policies as the level is defined by neighboring countries.

Summarizing, the simulations show that Swiss electricity policy needs to focus on some form of support if it wants to achieve its desired renewable extension targets. If the line extensions of the Ten Year Network Development Plan and the Swiss 'Strategische Netz 2025' emerge as projected the network does not represent a significant limitation on those policy choices.

4. General conclusions and policy recommendations

In the medium-term future, the Swiss electricity market will face major challenges such as the replacement of nuclear power by intermittent renewable production and the planned full market liberalization. Coping with these challenges will likely require interventions from the government and adjustments of today's electricity market design. In order to improve understanding of appropriate future market design options and beneficial policy measures, we have investigated the following three topics.

First, we have analyzed how regulatory measures and policy instruments interact and how they could be coordinated and whether an imperfectly competitive retail market induces problems on the supply side. To answer these questions, we have developed a model of partially liberalized electricity markets, where consumers hesitate to switch providers and where transport costs amplify this effect. We have coupled this demand-side model with a production model, where suppliers can invest into two different technologies, one having random production characteristics (intermittent renewables such as wind and solar) and one controllable technology (e.g. hydro) and where producers can trade on an (also imperfectly competitive) spot market. While earlier studies usually only consider one intervention or at maximum a combination of two interventions, this model allows for a simultaneous analysis of different political interventions such as full market liberalization, a cost-wise differentiation between local and abroad production, support of renewable technologies using feed-in premium, and a subsidization of capacity of controllable technologies.

In order to complement the analysis with the conceptual model, we have secondly developed and applied a numerical supply model with the objective to derive a quantification of potential policy adjustments for the Swiss electricity market. The model provides an aggregated formulation of Switzerland and its neighboring countries to account for import and export related transmission aspects and includes strategic company behavior for the Swiss market. We focus on three support approaches: a capacity market, a feed-in premium, a renewable quota mechanism, and their interaction. The model describes the Swiss market development from 2015 to 2050 and allows an estimation how the different support mechanisms impact the investment incentives. In addition, the inclusion of strategic company behavior allows us to identify if specific design elements need to be considered to avoid exploitation of the mechanisms.

Finally, the numerical model was extended to allow a split into different zones in order to depict the regional structure of the electricity market and to analyze potential benefits of regionally differentiated policy interventions. We focus on a Northern and Southern zonal configuration, separating the hydro power dominated mountain regions from the nuclear dominated demand centers in the North. In addition, we evaluate whether a zonal definition of the above described policy approaches provides benefits.

Our results from the conceptual analysis have three major implications. First, demand- and supply-side problems are almost perfectly decoupled, even though firms have market power both on the retail and on the spot market. This result has to be seen as an approximation, because it is based on two simplifying assumptions.[37] Furthermore, it relates only to cases with a (partially) liberalized market not to the switch from the current regional monopoly to some competition. For the liberalization itself, a coordination with supply-side policies could be required. Currently, retail price regulations take costs into account, so that excess costs of some technologies can be passed through to consumers. Liberalization will render this impossible, so that adjustments to supply-side policies have to be made if companies facing financial troubles after the liberalization are to be supported. However, the conceptual model shows that after the next step of market liberalization, policy should aim for coordinating interventions on the demand side (such as market liberalization and grid tariffs) and, separately, coordinating interventions on the supply side (such as feed-in premia or tariffs and capacity markets). We provide first quantifications for the supply side coordination in the numerical part of the study.

Second, our investigations have shown that a significant coordination of policies is called for on the supply side of the market. Promoting intermittent renewables can require accompanying support for controllable technologies, such as capacity payments or a capacity market. These accompanying measures can be necessary for achieving a cost-minimal outcome if a certain predefined level of domestic production capacity is also desired.[38] The stringency of these policy measures increases with more demanding targets for intermittent renewables.

Finally, the conceptual part of the project has shown that some differentiation of subsidies for renewables is likely to be optimal, if there is imperfect competition.

To the best of our knowledge, the conceptual part of our research provides the first theoretical model that connects an imperfectly competitive retail market for electricity with an investment model that includes the choice among technologies with qualitatively different characteristics (random vs. controllable production). Furthermore, this conceptual model is the

[37] Aggregate demand being constant and the international spot market being so much larger than the domestic market that a linear approximation of price reactions suffices.

[38] That is, some production capacity for the case where intermittent renewables do not produce.

first one depicting an imperfect electricity market liberalization that can describe features found in several countries, like persistent and substantial price differences among a large set of suppliers.

The numerical simulations of the Swiss market provide a quantification of potential market developments under varying support structures and a more specific modelling of the Swiss case. Given the stylized nature of the underlying model and the policy approaches the results are not to be taken as face value for quantitative system development forecasts. Also, the underlying numerical assumptions are to be seen as indicative in nature and not meant to be a cost evaluation of the different approaches.

The simulation results are in line with related research (i.e., CREST 2017): without further support mechanisms, Switzerland will rely on imports to compensate the decommissioned nuclear stations. Renewable investments in Switzerland under a pure market framework will only occur if either the investment costs significantly decrease or market prices rise. Given the model assumptions, these conditions are not met before the nuclear phase-out. Price-based support mechanisms face the problem that their support level needs to be tailored to those external conditions to achieve a specific quantity extension. Namely, a feed-in tariff needs to account for uncertain renewable cost developments and a market premium needs to account for the uncertain market price developments on top.

Quantity-based approaches, like a technology-neutral capacity market or a renewable quota framework, would ensure investments in accordance with the imposed targets. However, the resulting quota and capacity markets would be exposed to strategic behavior and potential abuse of market power. Under a capacity mechanism, it is important to provide a linkage between capacity payments and energy provision. Otherwise the system can be exploited by gaining payments for capacity that is actually not provided to the energy market. Similar the timing of payments (i.e. how far in advance are the auctions, how long is the payment fixed for new installations) are crucial design aspects of capacity mechanisms. Due to the aggregated nature of the numerical model we could no test those design details in this study.

As quota mechanisms are linked to actual generation the approach ensures that the constructed renewable capacities are utilized efficiently. This in turn also provides a reduction in market power potential as even under strategic behavior the companies are forced to increase renewable generation with the resulting merit order effect leading to a (slight) energy price reduction.

Renewable investments are mostly focused on biomass and PV generation, albeit PV is mostly constructed in later periods when their investment costs are significantly lower. Wind capacities are invested in small amounts throughout the years, basically capturing the best sites. However, the total wind capacity seldom reaches more than 1GW in the scenario runs. Even if the results are heavily impacted by the assumed technical characteristics the finding are in line with the expectations that Switzerland is best suited for solar and harvesting its biomass potential.

The results also highlight the strong dependence of Switzerland on surrounding market developments. The impact of the different support schemes and the resulting investments on the price level on the electricity market is limited (on average less than 1%). Consequently, also the impact of strategic behavior on energy prices is small. However, this does not translate into capacity and quota prices, as they are limited to Swiss suppliers. Therefore, a properly designed incentive structure for sufficient participation in those markets is crucial to avoid additional cost burden for consumers.

The scenarios on different zonal configurations provide two important insights. First, regardless of the chosen policy framework or zonal configuration, Switzerland will remain a transit hub for exports towards Italy. Second, a regional definition of quota or capacity targets can steer investments but has limited impact on the overall Swiss market conditions. Again, the neighboring countries are the most important price drivers and the Swiss transmission system (accounting for the projected extensions) does not pose additional constraints on the energy policy choice.

Finally, we assessed the interaction and need for coordination of policies on the supply side, namely renewable support and capacity mechanism. Given that both aim to increase local production they impact the company's investment incentives. Our results show that this interaction can lead to a mix of different dynamics that strongly depends on the level of competition in the market. Especially in case of strategic behavior, adding a renewable quota on top of a capacity market can ensure a higher share of renewable investments which in turn reduced market power on the capacity market. Our results thus illustrate the difficulties of a simultaneous implementation of several instruments and warn that a robust policy design is likely to be challenging under those conditions.

The combined policy results also highlight the fact that if a yearly balanced supply-demand structure or a specified share of dispatchable energy within Switzerland is politically desired, a single focus on renewable support will not necessarily ensure sufficient according investments. For example, in the simulations even with a quota mechanism, Switzerland would be a net-importer after the nuclear phase out. As quota mechanisms aim at average levels, imports are still the most cost-effective supply option in those hours where local generation is smaller than local demand. This result is also in line with the findings of the conceptual model.

Of course, our research has limitations. Most importantly, it shows that the above effects found within the scope of the conceptual analysis exist but cannot fully assess their actual relevance. In this regard, a numerical study as conducted within the second part of the project complements the conceptual findings. Second, our results are based on some simplifying assumptions, such as fixed aggregate demand and the existence of a large international spot market. Although reality likely deviates from these assumptions and additional effects might arise, the main mechanisms presented in the first paper will still hold.

Similarly, the numerical assessment is subject to assumptions and simplifications. The presented findings therefore focus on the underlying drivers and mechanisms at work and not so much on the resulting numbers. Especially the underlying assumptions on fuel price developments and investment costs have a large impact on the resulting investment pathways. A sensitivity analysis of renewable costs shows that different assumptions regarding price and cost developments can shift the pattern forward but are unlikely to alter the underlying incentive dynamics. Also, the chosen policy outlets (capacity market, feed-in premium, quota mechanism) are stylized in their representation and focus on wholesale market incentives. Approaches aiming at end-user participation (i.e. investment subsidies for PV installations or self-consumption regulations) could lead to a faster renewable penetration as end-users face a different cost incentive structure.

For these reasons, we would like to emphasize that the two modeling frameworks developed and applied within this project are not meant to produce predictions but rather to describe the economic mechanisms of market designs and political interventions and to quantify potential impacts on electricity markets.

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A Appendix

A.1 Optimal production decisions for the controllable technology

Assuming that there is one controllable and one intermittent renewable technology available, there are three relevant cases that have to be considered with regard to a firm's optimal production decision for the controllable technology. Theoretically, in each of the two operation states ($\phi \in \{0,1\}$) of the intermittent technology the controllable technology could either run at full capacity ($\tilde{q}_i = q_i$), run under its capacity ($\tilde{q}_i = \tilde{q}_i^{int}$), or run not at all ($\tilde{q}_i = 0$). However, since the controllable technology has to run at full capacity in at least one of the two operation states of the renewable technology to be profitable (which is naturally when the renewable technology is not producing), the number of relevant cases boils down to three. As Table 12 shows, in case *I* the controllable technology runs at full capacity in both states. In case *II*, the controllable technology runs under capacity when the renewable technology is producing and runs at full capacity when the renewable technology does not produce. In case *III*, the controllable technology does not produce when the renewable technology is operating and runs at full capacity if the renewable technology does not produce. There is a fourth case (*IV*) where firms do not invest in the controllable technology.

The optimal investment decisions for each of the four cases are presented below. In all cases, aggregate investment into the controllable technology is independent from any demand-side variables and parameters. For the intermittent technology, investment is independent from any demand-side variables and parameters if the controllable technology is always (at least partially) running (cases *I* and *II*), otherwise, if the controllable technology is not producing, only aggregate investment is independent from the demand side (cases *III* and *IV*).

Table 12: Optimal production decisions of the controllable technology in each of the two production states of the stochastic technology

	Production states	
Case	$\phi = 0$	$\phi = 1$
I	q_i	q_i
II	$\tilde{q}_i^{int}$	q_i
III	0	q_i
IV	0	0

Case I[39]

$$q_i^* = D_i - z_i\,\Omega + \frac{\Delta - \mu + \sigma_Q}{(N+1)b}$$

$$z_i^* = \frac{\left(\mathrm{c} + \mu - \sigma_Q + \sigma_Z\right)\Omega - \mathrm{v}_0}{(N+1)(\mathrm{v} + \mathrm{b}\,\Omega\,(1-\Omega))}$$

Case II

$$q_i^* = D_i + \frac{\mu - \sigma_Q + \Delta\,(\Omega - 1)}{b\,(N+1)(\Omega - 1)}$$

$$z_i^* = \frac{(\mathrm{c} + \sigma_Z)\,\Omega - \mathrm{v}_0}{(N+1)\,\mathrm{v}}$$

Case III

$$q_i^* = D_i + \frac{\mu - \sigma_Q + \Delta\,(\Omega - 1)}{b\,(N+1)(\Omega - 1)}$$

$$z_i^* = \frac{\left(\mathrm{c} + \Delta + \sigma_Z + b\,D_i\,(N+1)\right) - \mathrm{v}_0}{(N+1)(\mathrm{v} + \mathrm{b}\,\Omega)}$$

Case IV

$$q_i^* = 0$$

$$z_i^* = \frac{\left(\mathrm{c} + \Delta + \sigma_Z + b\,D_i\,(N+1)\right) - \mathrm{v}_0}{(N+1)(\mathrm{v} + \mathrm{b}\,\Omega)}$$

[39] As presented in Proposition 1

A.2 Input data of the numerical example

Table 13: The parameter values used in the numerical example are based on BFS (2015) and BFE (2015) (n_1, n_2, n_3, n_4), Meteotest (2012) (ν_0, ν), Hirth (2013) (Ω), and own assumptions (c, μ). The spot price curve ($p_{s,0}, b$) is based on power plant data developed by the ELMOD modelling community (see e.g. Egerer et al. (2014); Leuthold et al. (2012)) and ENTSO-E (2013).

Parameter	Value	Unit	Descriptiont
n_1	1390	GWh	Total demand in region 1
n_2	1141	GWh	Total demand in region 2
n_3	980	GWh	Total demand in region 3
n_4	969	GWh	Total demand in region 4
$p_{s,0}$	63'856	CHF/GWh	Intercept of the spot price curve
b	0.152	CHF/ (GWh*GWh)	Slope of the spot price curve
c	10'000	CHF/GWh	Marginal costs of the controllable technology
μ	56'674	CHF/GWh	Investment costs of the controllable technology
ν_0	23'931	CHF/GWh	Intercept of investment cost curve (renewable technology)[40]
ν	14.832	CHF/ (GWh*GWh)	Slope of investment cost curve (renewable technology)
Ω	0.37	-	Probability that the renewable technology is running

40 Based on data representing renewable potentials in Swiss communities we derived a linear investment cost curve with intercept v0 and slope v. It is based on the idea that on good sites less capacity has to be installed for the same energy output compared to worse sites.

A.3 Results Numerical Analysis

Energy Only Framework, Single Zone

Table 14: Energy Market Prices [€/MWh]

	Competitive Setting					Strategic Setting				
	CH	DE	FR	AT	IT	CH	DE	FR	AT	IT
2015	30.3	30.6	29.4	30.5	31.6	31.3	30.8	29.4	31.0	31.7
2020	40.6	40.4	38.6	40.1	43.8	42.5	41.2	38.6	40.8	43.9
2025	53.6	52.8	48.6	52.9	53.6	54.7	53.0	48.6	53.4	54.2
2030	69.3	68.6	65.9	68.6	69.3	69.9	68.9	65.9	68.9	69.7
2035	81.0	79.0	76.9	77.8	82.0	81.8	79.4	76.8	78.1	82.6
2040	90.9	90.1	90.7	89.0	91.3	91.5	90.5	90.9	89.3	91.8
2045	101.0	99.5	100.7	97.5	101.1	101.5	99.8	101.0	97.6	101.6
2050	106.4	104.7	105.7	101.8	107.2	107.8	105.7	106.6	102.6	108.4

Table 15: Swiss Market Conditions [TWh]

	Competitive Setting			Strategic Setting		
	Demand	Supply	Imp(-)/Exp(+)	Demand	Supply	Imp(-)/Exp(+)
2015	65.22	68.91	3.69	64.91	62.50	-2.41
2020	64.14	65.95	1.81	63.67	56.30	-7.38
2025	63.10	60.08	-3.02	62.94	55.12	-7.82
2030	62.73	52.08	-10.65	62.65	48.63	-14.02
2035	62.99	42.37	-20.62	62.85	37.08	-25.78
2040	63.95	42.85	-21.10	63.87	37.23	-26.64
2045	64.95	44.34	-20.62	64.86	39.75	-25.11
2050	65.98	54.98	-11.00	65.69	39.44	-26.26

Table 16: Investments [MW]

	Competitive Setting				Strategic Setting			
	Gas	Biomass	Wind	Solar	Gas	Biomass	Wind	Solar
2015								
2020								
2025			0					
2030			60					
2035			279					
2040			222					
2045			243	837			24	
2050		512	196	6954			39	

Table 17: Generation Capacities [GW]

	Competitive Setting						Strategic Setting					
	Hydro	Nuc	Gas	Bio	Wind	Solar	Hydro	Nuc	Gas	Bio	Wind	Solar
2015	17.47	3.33		0.17	0.06	1.39	17.47	3.33		0.17	0.06	1.39
2020	17.47	2.97		0.15	0.05	1.26	17.47	2.97		0.15	0.05	1.26
2025	17.47	2.23		0.12	0.05	1.05	17.47	2.23		0.12	0.05	1.05
2030	17.47	1.22		0.08	0.09	0.70	17.47	1.22		0.08	0.03	0.70
2035	17.47				0.34		17.47					
2040	17.47				0.56	0.00	17.47				0.00	
2045	17.47				0.81	0.84	17.47				0.02	
2050	17.47			0.51	1.00	7.79	17.47				0.06	

Capacity Market Framework, Single Zone

Table 18: Energy Market Prices [€/MWh]

	Competitive Setting					Strategic Setting				
	CH	DE	FR	AT	IT	CH	DE	FR	AT	IT
2015	30.3	30.6	29.4	30.5	31.6	31.3	30.8	29.4	31.0	31.7
2020	40.6	40.4	38.6	40.1	43.8	42.5	41.2	38.6	40.8	43.9
2025	53.2	52.7	48.6	52.8	53.4	54.7	53.0	48.6	53.4	54.2
2030	68.0	68.2	65.8	68.0	68.4	69.9	68.9	65.9	68.9	69.7
2035	77.3	77.1	76.2	76.3	79.6	81.7	79.4	76.8	78.1	82.6
2040	88.6	88.3	88.8	88.1	89.4	91.4	90.4	90.8	89.4	91.8
2045	98.0	97.2	98.4	96.6	98.7	101.2	99.6	100.8	97.8	101.4
2050	103.7	102.7	103.7	101.2	104.9	107.5	105.5	106.4	102.8	108.2

Table 19: Swiss Market Conditions [TWh], Capacity Price [€/kW]

	Competitive Setting				Strategic Setting			
	Demand	Supply	Imp(-)/Exp(+)	CapPrice	Demand	Supply	Imp(-)/Exp(+)	CapPrice
2015	65.22	68.91	3.69		64.91	62.50	-2.41	0
2020	64.14	65.95	1.81	175	63.67	56.30	-7.38	0
2025	63.19	61.75	-1.44	105	62.94	55.12	-7.82	0
2030	63.02	59.85	-3.17	543	62.65	48.63	-14.02	1007
2035	63.77	70.53	6.76	88	62.86	37.19	-25.67	0
2040	64.53	74.97	10.45	0	63.90	38.11	-25.80	0
2045	65.66	81.34	15.68	79	64.93	41.36	-23.57	0
2050	66.58	85.82	19.23	0	65.77	41.74	-24.03	0

Table 20: Investments [MW]

	Competitive Setting				Strategic Setting			
	Gas	Biomass	Wind	Solar	Gas	Biomass	Wind	Solar
2015								
2020	2736				2736			
2025	610		170		664			
2030	1026		269		1110			
2035	343	1800	206		1535		50	
2040			115	1534	159		81	
2045	1407		200	8120	2888		126	
2050			299	7579	729	117	127	101

Table 21: Generation Capacities [GW]

	Competitive Setting						Strategic Setting					
	Hydro	Nuc	Gas	Bio	Wind	Solar	Hydro	Nuc	Gas	Bio	Wind	Solar
2015	17.47	3.33		0.17	0.06	1.39	17.47	3.33		0.17	0.06	1.39
2020	17.47	2.97	2.74	0.15	0.05	1.26	17.47	2.97	2.74	0.15	0.05	1.26
2025	17.47	2.23	3.35	0.12	0.22	1.05	17.47	2.23	3.40	0.12	0.05	1.05
2030	17.47	1.22	4.37	0.08	0.47	0.70	17.47	1.22	4.51	0.08	0.03	0.70
2035	17.47		4.72	1.80	0.65	0.00	17.47		6.04		0.05	
2040	17.47		4.72	1.80	0.76	1.53	17.47		6.20		0.13	
2045	17.47		3.39	1.80	0.96	9.65	17.47		6.36		0.26	
2050	17.47		2.78	1.80	1.09	17.23	17.47		6.42	0.12	0.38	0.10

FIP Framework, Single Zone

Table 22: Energy Market Prices [€/MWh]

	Competitive Setting					Strategic Setting				
	CH	DE	FR	AT	IT	CH	DE	FR	AT	IT
2015	30.3	30.6	29.4	30.5	31.6	31.3	30.8	29.4	31.0	31.7
2020	40.6	40.4	38.6	40.1	43.8	42.5	41.2	38.6	40.8	43.9
2025	53.5	52.8	48.6	52.9	53.6	54.7	53.0	48.6	53.4	54.2
2030	69.3	68.6	65.9	68.6	69.3	69.9	68.9	65.9	68.9	69.7
2035	80.0	78.4	76.7	77.4	81.3	81.8	79.4	76.8	78.1	82.6
2040	90.2	89.7	90.3	88.9	90.8	91.5	90.5	90.9	89.3	91.8
2045	100.3	99.0	100.2	97.4	100.6	101.5	99.8	101.0	97.6	101.6
2050	105.9	104.4	105.4	101.8	106.7	107.8	105.7	106.6	102.6	108.4

Table 23: Swiss Market Conditions [TWh], FIP [€/MWh]

	Competitive Setting				Strategic Setting			
	Demand	Supply	Imp(-)/Exp(+)	FIP	Demand	Supply	Imp(-)/Exp(+)	FIP
2015	65.22	68.91	3.69		64.91	62.50	-2.41	
2020	64.14	65.95	1.81	40	63.67	56.30	-7.38	40
2025	63.10	60.28	-2.83	30	62.94	55.12	-7.82	30
2030	62.74	52.47	-10.27	20	62.65	48.63	-14.02	20
2035	63.20	50.36	-12.83	10	62.85	37.08	-25.78	10
2040	64.12	50.69	-13.43	0	63.87	37.23	-26.64	0
2045	65.12	51.84	-13.27	0	64.86	39.75	-25.11	0
2050	66.08	60.26	-5.82	0	65.69	39.44	-26.26	0

Table 24: Investments [MW]

	Competitive Setting				Strategic Setting			
	Gas	Biomass	Wind	Solar	Gas	Biomass	Wind	Solar
2015								
2020			0					
2025			91					
2030			148					
2035		1800	150					
2040			149	0				
2045			222	591			24	
2050			284	6970			39	

Table 25: Generation Capacities [GW]

	Competitive Setting						Strategic Setting					
	Hydro	Nuc	Gas	Bio	Wind	Solar	Hydro	Nuc	Gas	Bio	Wind	Solar
2015	17.5	3.33		0.17	0.06	1.39	17.5	3.33		0.17	0.06	1.39
2020	17.5	2.97		0.15	0.05	1.26	17.5	2.97		0.15	0.05	1.26
2025	17.5	2.23		0.12	0.14	1.05	17.5	2.23		0.12	0.05	1.05
2030	17.5	1.22		0.08	0.27	0.70	17.5	1.22		0.08	0.03	0.70
2035	17.5			1.80	0.39	0.00	17.5					
2040	17.5			1.80	0.54	0.00	17.5					
2045	17.5			1.80	0.76	0.59	17.5				0.02	
2050	17.5			1.80	0.95	7.56	17.5				0.06	

Quota Framework, Single Zone

Table 26: Energy Market Prices [€/MWh]

	Competitive Setting					Strategic Setting				
	CH	DE	FR	AT	IT	CH	DE	FR	AT	IT
2015	30.3	30.6	29.4	30.5	31.6	31.3	30.8	29.4	31.0	31.7
2020	40.6	40.4	38.6	40.1	43.8	42.1	41.0	38.6	40.8	43.9
2025	53.5	52.8	48.6	52.9	53.5	54.4	52.9	48.6	53.2	53.9
2030	68.6	68.4	65.8	68.3	69.0	69.1	68.5	65.8	68.4	69.1
2035	79.9	78.4	76.7	77.4	81.3	80.4	78.5	76.6	77.3	81.3
2040	90.0	89.5	90.0	88.8	90.6	90.3	89.5	90.0	88.8	90.7
2045	99.9	98.6	99.8	97.1	100.2	100.0	98.6	99.8	97.2	100.3
2050	105.8	104.3	105.4	101.7	106.7	106.2	104.4	105.4	102.0	106.9

Table 27: Swiss Market Conditions [TWh], Quota [€/MWh]

	Competitive Setting				Strategic Setting			
	Demand	Supply	Imp(-)/Exp(+)	Quota	Demand	Supply	Imp(-)/Exp(+)	Quota
2015	65.22	68.91	3.69	0.0	64.91	62.52	-2.39	0.0
2020	64.14	65.95	1.81	0.0	63.76	58.10	-5.66	18.6
2025	63.12	60.79	-2.33	9.0	63.00	57.73	-5.26	41.2
2030	62.85	56.22	-6.63	57.8	62.80	55.01	-7.79	275.0
2035	63.22	50.97	-12.25	0.0	63.17	50.54	-12.63	53.3
2040	64.18	54.55	-9.63	20.3	64.17	54.55	-9.63	47.3
2045	65.21	58.69	-6.52	20.6	65.22	58.70	-6.52	67.7
2050	66.10	61.18	-4.92	0.0	66.06	59.46	-6.61	97.8

Table 28: Investments [MW]

	Competitive Setting				Strategic Setting			
	Gas	Biomass	Wind	Solar	Gas	Biomass	Wind	Solar
2015							10	
2020							231	
2025			326				566	
2030		646	344			280	584	
2035		1154				1520	99	
2040			104	2927				5151
2045			81	3453			59	1358
2050			339	2147			430	957

Table 29: Generation Capacities [GW]

	Competitive Setting						Strategic Setting					
	Hydro	Nuc	Gas	Bio	Wind	Solar	Hydro	Nuc	Gas	Bio	Wind	Solar
2015	17.5	3.33		0.17	0.06	1.39	17.5	3.33		0.17	0.07	1.39
2020	17.5	2.97		0.15	0.05	1.26	17.5	2.97		0.15	0.30	1.26
2025	17.5	2.23		0.12	0.37	1.05	17.5	2.23		0.12	0.85	1.05
2030	17.5	1.22		0.73	0.70	0.70	17.5	1.22		0.36	1.42	0.70
2035	17.5			1.80	0.67		17.5			1.80	1.49	
2040	17.5			1.80	0.77	2.93	17.5			1.80	1.48	5.15
2045	17.5			1.80	0.86	6.38	17.5			1.80	1.31	6.51
2050	17.5			1.80	0.87	8.53	17.5			1.80	1.17	7.47

Energy Only Market Framework, Two Zones

Table 30: Energy Market Prices [€/MWh]

	Competitive Setting						Strategic Setting					
	CHN	CHS	DE	FR	AT	IT	CHN	CHS	DE	FR	AT	IT
2015	31,4	31,6	31,4	28,6	31,4	31,9	31,9	32,1	31,8	28,6	31,9	32,1
2020	41,9	42,2	41,7	37,5	41,7	44,1	42,7	43,2	42,4	37,5	42,4	44,2
2025	54,9	55,3	54,8	46,7	54,9	54,6	55,5	56	55,4	46,6	55,5	55,2
2030	70,4	70,2	70,2	64,5	70,1	69,9	71,1	71,2	70,9	64,6	70,8	70,6
2035	81	81,1	80,1	75,9	79,4	81,5	82,3	82,7	81	76,1	80	82,6
2040	91,6	91,7	89,8	90,9	88,4	91,7	92,5	92,8	90,5	91,4	88,9	92,5
2045	101,3	101,6	98,8	101,1	96,8	101,4	102,5	102,9	99,7	101,9	97,4	102,5
2050	107,3	107,5	104,7	106,2	102,5	107,3	109,1	109,4	106,1	107,1	103,5	109,1

Table 31: Swiss Market Conditions [TWh]

	Competitive Setting						Strategic Setting					
	CH North			CH South			CH North			CH South		
	Dem	Sup	Imp	Dem	Sup	Imp	Dem	Sup	Imp	Dem	Sup	Imp
2015	43,3	38,3	-5,0	22,2	28,5	6,3	43,1	37,5	-5,6	22,2	20,4	-1,8
2020	42,6	35,5	-7,1	21,8	28,3	6,5	42,3	35,4	-6,9	21,8	17,7	-4,1
2025	42,0	30,0	-12,0	21,4	28,2	6,7	41,8	30,0	-11,9	21,4	19,7	-1,7
2030	41,8	22,3	-19,5	21,2	28,0	6,8	41,7	22,3	-19,4	21,2	19,0	-2,3
2035	42,2	13,0	-29,2	21,1	30,1	9,0	41,9	13,0	-28,9	21,0	17,5	-3,5
2040	42,8	13,2	-29,5	21,3	30,3	9,0	42,6	13,0	-29,5	21,3	19,3	-2,0
2045	43,5	13,5	-30,0	21,6	32,9	11,3	43,3	13,0	-30,3	21,6	19,5	-2,1
2050	44,1	16,0	-28,1	21,9	36,8	14,9	43,8	13,0	-30,7	21,8	19,4	-2,4

Table 32: Investments [MW]

	Competitive Setting								Strategic Setting							
	CH North				CH South				CH North				CH South			
	Gas	Bio	Wind	Solar	Gas	Bio	Wind	Solar	Gas	Bio	Wind	Solar	Gas	Bio	Wind	Solar
2015																
2020																
2025						69										
2030						169										
2035			22		621	143		621			26				2	
2040			101			102									13	
2045			112			122	2020								19	
2050			89	2012		167	3209								13	

Table 33: Generation Capacities [GW]

	Competitive Setting								Strategic Setting							
	CH North				CH South				CH North				CH South			
	Gas	Bio	Wind	Solar	Gas	Bio	Wind	Solar	Gas	Bio	Wind	Solar	Gas	Bio	Wind	Solar
2015		0,1	0,1			0,1		1,4		0,1	0,1			0,1		1,4
2020		0,1	0,1			0,1		1,2		0,1	0,1			0,1		1,2
2025		0,1				0,1	0,1	1,0		0,1				0,1		1,0
2030							0,2	0,7								0,7
2035						0,6	0,4									
2040			0,1			0,6	0,5									
2045			0,2			0,6	0,6	2,0								
2050			0,3	2,0		0,6	0,7	5,2								

Capacity Market Framework, Two Zones, Single Capacity Market

Table 34: Energy Market Prices [€/MWh]

	Competitive Setting						Strategic Setting					
	CHN	CHS	DE	FR	AT	IT	CHN	CHS	DE	FR	AT	IT
2015	31,4	31,6	31,4	28,6	31,4	31,9	31,9	32,1	31,8	28,6	31,9	32,1
2020	41,9	42,2	41,7	37,5	41,6	44,1	42,7	43,2	42,4	37,5	42,4	44,2
2025	54,7	55	54,6	46,7	54,6	54,5	55,5	56	55,4	46,6	55,5	55,2
2030	69,3	69,2	69,3	64,4	69,2	69	71,1	71,1	70,9	64,6	70,8	70,6
2035	78,9	78,9	78,3	75,3	77,8	80,1	81,9	82,3	80,8	76	79,8	82,3
2040	88,8	88,8	88	89,3	87,9	89,5	92,1	92,3	90,3	91,1	88,9	92,1
2045	98,4	98,5	96,8	99,3	96	98,7	101,9	102,2	99,4	101,4	97,4	101,9
2050	103,5	103,7	102,3	104	101,1	104,5	108,4	108,8	105,7	106,7	103,4	108,5

Table 35: Swiss Market Conditions [TWh], Capacity Price [€/kW]

	Competitive Setting							Strategic Setting						
	CH North			CH South				CH North			CH South			
	Dem	Sup	Imp	Dem	Sup	Imp	Cap	Dem	Sup	Imp	Dem	Sup	Imp	Cap
2015	43,3	38,3	-5,0	22,2	28,5	6,3	0	43,1	37,5	-5,6	22,2	20,4	-1,8	0
2020	42,6	35,5	-7,1	21,8	28,6	6,7	301	42,3	35,4	-6,9	21,8	17,7	-4,1	0
2025	42,0	31,1	-11,0	21,4	29,9	8,5	104	41,8	30,0	-11,9	21,4	19,7	-1,7	326
2030	42,1	30,5	-11,6	21,3	32,0	10,7	350	41,7	22,3	-19,4	21,2	19,0	-2,2	690
2035	42,7	27,1	-15,6	21,2	40,3	19,1	139	42,0	17,5	-24,6	21,0	17,6	-3,4	0
2040	43,3	27,8	-15,6	21,5	46,4	25,0	0	42,7	18,1	-24,5	21,3	19,5	-1,8	0
2045	44,1	30,8	-13,3	21,8	49,2	27,4	200	43,4	18,9	-24,5	21,6	19,7	-1,9	0
2050	44,8	34,4	-10,4	22,1	54,7	32,6	0	43,9	19,8	-24,1	21,9	19,6	-2,3	326

Table 36: Investments [MW]

	Competitive Setting								Strategic Setting							
	CH North				CH South				CH North				CH South			
	Gas	Bio	Wind	Solar	Gas	Bio	Wind	Solar	Gas	Bio	Wind	Solar	Gas	Bio	Wind	Solar
2015									51				816			
2020	1386				1618		119						2487			
2025	623						130		339				13		1	
2030	1056		42				131		1100						32	
2035			114		1464		160		1079	982	38		62		29	
2040			105				132	2467	1300		53		2131		38	
2045		307	122	5574	1043		263	3895			79				33	
2050		674	40	3751		818	217	1905	127		72	589	292		28	

Table 37: Generation Capacities [GW]

	Competitive Setting								Strategic Setting							
	CH North				CH South				CH North				CH South			
	Gas	Bio	Wind	Solar	Gas	Bio	Wind	Solar	Gas	Bio	Wind	Solar	Gas	Bio	Wind	Solar
2015		0,1	0,1			0,1		1,4	0,1	0,1	0,1		0,8	0,1		1,4
2020	1,4	0,1	0,1		1,6	0,1	0,1	1,2	0,1	0,1	0,1		3,3	0,1		1,2
2025	2,0	0,1			1,6	0,1	0,3	1,0	0,4	0,1			3,3	0,1		1,0
2030	3,1		0,1		1,6		0,4	0,7	1,5				3,3			0,7
2035	3,1		0,2		3,1		0,5		2,6	1,0			3,4		0,1	
2040	3,1	0,0	0,3		3,1		0,7	2,5	3,8	1,0	0,1		4,7		0,1	
2045	1,7	0,3	0,4	5,6	2,5		0,8	6,4	3,8	1,0	0,2		2,2		0,1	
2050	1,1	1,0	0,4	9,3	2,5	0,8	0,9	8,3	3,6	1,0	0,2	0,6	2,5		0,2	

FIP Framework, Two Zones

Table 38: Energy Market Prices [€/MWh]

	Competitive Setting						Strategic Setting					
	CHN	CHS	DE	FR	AT	IT	CHN	CHS	DE	FR	AT	IT
2015	31,4	31,6	31,4	28,6	31,4	31,9	31,9	32,1	31,8	28,6	31,9	32,1
2020	41,8	42,2	41,6	37,5	41,6	44,1	42,7	43,2	42,4	37,5	42,4	44,2
2025	54,9	55,2	54,8	46,7	54,9	54,6	55,5	56,0	55,4	46,6	55,5	55,2
2030	70,4	70,2	70,2	64,5	70,0	69,9	71,1	71,1	70,9	64,6	70,8	70,6
2035	81,2	81,4	80,3	76,0	79,6	81,7	82,3	82,7	81,0	76,1	80,0	82,6
2040	91,8	92,0	89,9	91,1	88,4	91,9	92,5	92,8	90,5	91,3	88,9	92,5
2045	101,6	101,8	99,0	101,2	96,9	101,6	102,4	102,8	99,7	101,8	97,4	102,5
2050	107,4	107,7	104,8	106,2	102,5	107,5	109,0	109,4	106,1	107,1	103,5	109,0

Table 39: Swiss Market Conditions [TWh], FIP [€/MWh]

	Competitive Setting							Strategic Setting						
	CH North			CH South				CH North			CH South			
	Dem	Sup	Imp	Dem	Sup	Imp	FIP	Dem	Sup	Imp	Dem	Sup	Imp	FIP
2015	43,3	38,3	-5,0	22,2	28,5	6,3		43,1	37,5	-5,6	22,2	20,4	-1,8	
2020	42,6	35,5	-7,1	21,8	28,7	6,9	40	42,3	35,4	-6,9	21,8	17,7	-4,1	40
2025	42,0	30,0	-12,0	21,4	28,6	7,1	30	41,8	30,0	-11,9	21,4	19,7	-1,7	30
2030	41,8	22,3	-19,5	21,2	28,2	7,0	20	41,7	22,3	-19,4	21,2	19,0	-2,3	20
2035	42,2	13,1	-29,1	21,0	27,4	6,3	10	42,0	13,4	-28,5	21,0	17,5	-3,5	10
2040	42,7	13,3	-29,4	21,3	27,6	6,3		42,6	13,4	-29,2	21,3	19,3	-2,0	
2045	43,5	13,5	-30,0	21,6	30,4	8,8		43,3	13,4	-29,9	21,6	19,5	-2,1	
2050	44,1	16,9	-27,2	21,9	34,5	12,6		43,8	13,4	-30,4	21,8	19,4	-2,4	

Table 40: Investments [MW]

	Competitive Setting								Strategic Setting							
	CH North				CH South				CH North				CH South			
	Gas	Bio	Wind	Solar	Gas	Bio	Wind	Solar	Gas	Bio	Wind	Solar	Gas	Bio	Wind	Solar
2015							15									
2020							173									
2025							62									
2030							62				1				3	
2035			47				70			87	25				8	
2040			92				128								6	
2045			109				304	2130							16	
2050		151	88	2188			223	3266							12	

Table 41: Generation Capacities [GW]

	Competitive Setting								Strategic Setting							
	CH North				CH South				CH North				CH South			
	Gas	Bio	Wind	Solar	Gas	Bio	Wind	Solar	Gas	Bio	Wind	Solar	Gas	Bio	Wind	Solar
2015		0,1	0,1			0,1		1,4		0,1	0,1			0,1		1,4
2020		0,1	0,1			0,1	0,2	1,2		0,1	0,1			0,1		1,2
2025		0,1				0,1	0,3	1,0		0,1				0,1		1,0
2030							0,3	0,7								0,7
2035							0,4			0,1						
2040			0,1				0,5			0,1						
2045			0,2				0,6	2,1		0,1						
2050		0,2	0,3	2,2			0,8	5,4		0,1						

Quota Framework, Two Zones, Single Quota

Table 42: Energy Market Prices [€/MWh]

	Competitive Setting						Strategic Setting					
	CHN	CHS	DE	FR	AT	IT	CHN	CHS	DE	FR	AT	IT
2015	31,4	31,6	31,4	28,6	31,4	31,9	31,7	31,9	31,6	28,5	31,6	32,0
2020	41,8	42,2	41,7	37,5	41,6	44,1	42,0	42,4	41,8	37,4	41,8	44,0
2025	54,6	54,9	54,5	46,7	54,5	54,3	54,8	55,2	54,7	46,6	54,8	54,6
2030	70,0	69,7	69,8	64,4	69,7	69,5	70,0	70,1	69,8	64,3	69,8	69,7
2035	80,3	80,4	79,6	75,7	79,0	81,1	80,5	80,8	79,6	75,7	79,0	81,2
2040	90,7	90,8	89,1	90,3	88,0	91,0	90,8	91,0	89,2	90,3	88,2	91,0
2045	100,3	100,5	98,0	100,4	96,4	100,4	100,4	100,7	98,1	100,4	96,5	100,5
2050	106,2	106,4	104,0	105,6	101,9	106,4	106,7	107,0	104,3	105,8	102,2	106,8

Table 43: Swiss Market Conditions [TWh], Quota Price [€/MWh]

	Competitive Setting							Strategic Setting						
	CH North			CH South				CH North			CH South			
	Dem	Sup	Imp	Dem	Sup	Imp	Cap	Dem	Sup	Imp	Dem	Sup	Imp	Cap
2015	43,3	38,3	-5,0	22,2	28,5	6,3	0,0	43,2	38,6	-4,6	22,2	24,5	2,3	67,7
2020	42,6	35,5	-7,1	21,8	28,6	6,8	0,0	42,6	40,6	-2,0	21,8	23,1	1,3	105,9
2025	42,1	31,6	-10,5	21,5	32,2	10,8	0,0	42,0	35,6	-6,5	21,5	25,5	4,0	151,2
2030	41,9	24,3	-17,6	21,3	32,2	10,9	21,6	42,0	31,0	-11,0	21,3	25,5	4,2	229,1
2035	42,4	18,1	-24,3	21,1	32,7	11,6	70,2	42,4	29,2	-13,2	21,1	21,6	0,5	95,6
2040	43,0	18,1	-24,9	21,4	36,6	15,3	25,2	43,0	31,5	-11,5	21,4	23,2	1,8	47,2
2045	43,7	20,2	-23,5	21,7	38,6	16,9	18,4	43,7	34,9	-8,8	21,7	24,0	2,3	82,2
2050	44,3	24,3	-20,0	22,0	40,5	18,5	0,0	44,2	36,0	-8,2	21,9	23,5	1,6	108,7

Table 44: Investments [MW]

	Competitive Setting								Strategic Setting							
	CH North				CH South				CH North				CH South			
	Gas	Bio	Wind	Solar	Gas	Bio	Wind	Solar	Gas	Bio	Wind	Solar	Gas	Bio	Wind	Solar
2015										33	495				299	
2020							141			868	145				33	
2025		346	53			762	271			14	60	105		327	35	
2030			172				196			23	31	2504			1	
2035		635	139			56	161	788		45	60	3430		218	7	
2040								3402		33	363	2247			202	
2045			11	1887			150	1721		868	246	2791		45	98	
2050		346	63	3500		762	326	1507		14	36	1132		150	18	

Table 45: Generation Capacities [GW]

	Competitive Setting								Strategic Setting							
	CH North				CH South				CH North				CH South			
	Gas	Bio	Wind	Solar	Gas	Bio	Wind	Solar	Gas	Bio	Wind	Solar	Gas	Bio	Wind	Solar
2015		0,1	0,1			0,1		1,4		0,1	0,6			0,1	0,3	1,4
2020		0,1	0,1			0,1	0,2	1,2		1,0	0,7			0,1	0,3	1,2
2025		0,4	0,1			0,8	0,4	1,0		1,0	0,7	0,1		0,4	0,4	1,0
2030		0,4	0,3			0,8	0,6	0,7		1,0	0,8	2,6		0,4	0,4	0,7
2035		1,0	0,4			0,8	0,8	0,8		1,0	0,8	6,0		0,5	0,4	
2040		1,0	0,4			0,8	0,8	4,2		1,0	0,7	8,3		0,5	0,3	
2045		1,0	0,4	1,9		0,8	0,8	5,9		1,0	0,8	11,1		0,6	0,3	
2050		1,0	0,4	5,4		0,8	0,8	7,4		1,0	0,7	12,1		0,4	0,3	

Capacity Market Framework, Two Zones, Two Capacity Markets

Table 46: Energy Market Prices [€/MWh]

	Competitive Setting						Strategic Setting					
	CHN	CHS	DE	FR	AT	IT	CHN	CHS	DE	FR	AT	IT
2015	31,4	31,6	31,4	28,6	31,4	31,9	31,9	32,1	31,8	28,6	31,9	32,1
2020	41,9	42,2	41,7	37,5	41,7	44,1	42,7	43,2	42,4	37,5	42,4	44,2
2025	54,7	55,0	54,6	46,7	54,7	54,5	55,5	56,0	55,4	46,6	55,5	55,2
2030	69,3	69,3	69,3	64,4	69,1	69,1	71,1	71,1	70,9	64,6	70,8	70,6
2035	78,7	79,0	78,1	75,2	77,7	80,2	81,9	82,3	80,8	76,0	79,8	82,3
2040	88,9	89,0	88,1	89,4	87,8	89,7	92,1	92,3	90,3	91,1	88,9	92,1
2045	98,1	98,2	96,8	99,2	96,1	98,7	101,9	102,2	99,4	101,4	97,4	101,9
2050	103,7	103,9	102,4	104,2	101,1	104,7	108,4	108,8	105,7	106,7	103,4	108,5

Table 47: Swiss Market Conditions [TWh], Capacity Price [€/kW]

	Competitive Setting								Strategic Setting							
	CH North				CH South				CH North				CH South			
	Dem	Sup	Imp	Cap	Dem	Sup	Imp	Cap	Dem	Sup	Imp	Cap	Dem	Sup	Imp	Cap
2015	43,3	38,3	-5,0	0	22,2	28,5	6,3	0	43,1	37,5	-5,6	0	22,2	20,4	-1,8	0
2020	42,6	35,5	-7,1	150	21,8	28,3	6,5	0	42,3	35,4	-6,9	0	21,8	17,7	-4,1	0
2025	42,0	32,4	-9,6	103	21,4	28,2	6,8	0	41,8	30,0	-11,9	324	21,4	19,7	-1,7	0
2030	42,1	34,5	-7,6	107	21,3	28,1	6,8	0	41,7	22,3	-19,4	692	21,2	19,0	-2,2	0
2035	42,7	41,2	-1,5	67	21,2	27,7	6,5	0	42,0	17,5	-24,6	0	21,0	17,7	-3,4	0
2040	43,3	44,9	1,6	468	21,5	27,9	6,4	132	42,7	18,1	-24,5	0	21,3	19,5	-1,8	466
2045	44,1	50,4	6,3	54	21,8	29,0	7,2	0	43,4	18,9	-24,5	0	21,6	19,7	-1,9	1
2050	44,8	54,5	9,7	0	22,1	32,3	10,2	0	43,9	19,8	-24,1	324	21,9	19,5	-2,3	387

Table 48: Investments [MW]

	Competitive Setting								Strategic Setting							
	CH North				CH South				CH North				CH South			
	Gas	Bio	Wind	Solar	Gas	Bio	Wind	Solar	Gas	Bio	Wind	Solar	Gas	Bio	Wind	Solar
2015									258							
2020	3098								2839							
2025	683						99		683							
2030	1045		55				163		1063						18	
2035	740	982	92			61	130		757	982	39		112		54	
2040	100		75				94		366		53		49		26	
2045	2562		91	3824			69	835	2943		79		55		27	
2050			73	7638			187	2692	695		72	585				

Table 49: Generation Capacities [GW]

	Competitive Setting								Strategic Setting							
	CH North				CH South				CH North				CH South			
	Gas	Bio	Wind	Solar	Gas	Bio	Wind	Solar	Gas	Bio	Wind	Solar	Gas	Bio	Wind	Solar
2015	0,0	0,1	0,1			0,1		1,4	0,3	0,1	0,1			0,1		1,4
2020	3,1	0,1	0,1			0,1		1,2	3,1	0,1	0,1			0,1		1,2
2025	3,8	0,1				0,1	0,1	1,0	3,8	0,1				0,1		1,0
2030	4,8		0,1				0,3	0,7	4,8							0,7
2035	5,6	1,0	0,1			0,1	0,4		5,6	1,0			0,1		0,1	
2040	5,7	1,0	0,2			0,1	0,5		5,7	1,0	0,1		0,2		0,1	
2045	5,1	1,0	0,3	3,8		0,1	0,6	0,8	5,8	1,0	0,2		0,2		0,1	
2050	4,4	1,0	0,4	11,5		0,1	0,6	3,5	5,8	1,0	0,2	0,6	0,3		0,2	

Quota Framework, Two Zones, Two Quota Targets

Table 50: Energy Market Prices [€/MWh]

	Competitive Setting						Strategic Setting					
	CHN	CHS	DE	FR	AT	IT	CHN	CHS	DE	FR	AT	IT
2015	30,7	30,8	30,9	28,5	30,9	31,7	31,5	31,7	31,4	28,5	31,4	31,8
2020	40,6	40,7	40,9	37,4	40,7	43,9	42,0	42,3	41,7	37,4	41,7	44,0
2025	53,8	54,2	53,7	46,6	53,8	54,0	54,6	55,1	54,5	46,6	54,6	54,4
2030	68,9	69,0	68,8	64,2	68,8	69,2	69,8	70,0	69,7	64,2	69,7	69,7
2035	79,5	79,7	78,7	75,4	78,2	80,8	80,6	80,9	79,6	75,6	78,9	81,3
2040	89,3	89,5	87,9	89,4	87,1	90,2	90,8	91,0	89,1	90,3	88,0	91,0
2045	99,2	99,5	97,2	99,8	95,6	99,5	100,5	100,8	98,1	100,5	96,4	100,6
2050	105,6	105,9	103,5	105,2	101,6	105,9	106,7	107,1	104,3	105,8	102,1	106,9

Table 51: Swiss Market Conditions [TWh], Quota Price [€/MWh]

	Competitive Setting								Strategic Setting							
	CH North				CH South				CH North				CH South			
	Dem	Sup	Imp	QP	Dem	Sup	Imp	QP	Dem	Sup	Imp	QP	Dem	Sup	Imp	QP
2015	43,6	51,0	7,4	202,5	22,2	28,5	6,3	0,0	43,3	48,9	5,6	290,2	22,2	20,3	-1,9	0,0
2020	43,1	50,1	7,0	94,1	21,9	28,3	6,4	0,0	42,6	48,4	5,8	190,0	21,8	16,7	-5,2	0,0
2025	42,3	46,2	3,9	300,9	21,5	28,1	6,6	0,0	42,1	44,8	2,7	347,4	21,5	19,5	-2,0	0,0
2030	42,2	40,7	-1,5	67,4	21,3	28,0	6,7	0,0	42,0	40,0	-2,0	53,5	21,3	18,9	-2,4	0,0
2035	42,6	34,1	-8,5	84,0	21,1	27,5	6,4	0,0	42,4	33,9	-8,5	94,2	21,1	17,5	-3,6	0,0
2040	43,3	41,6	-1,6	0,0	21,4	31,6	10,2	0,0	43,0	36,5	-6,4	102,9	21,4	19,2	-2,2	0,0
2045	43,9	41,6	-2,3	0,0	21,7	31,6	9,9	0,0	43,7	39,3	-4,4	136,2	21,7	19,5	-2,2	21,7
2050	44,4	40,0	-4,4	190,3	22,0	31,5	9,5	0,0	44,2	39,8	-4,4	288,3	21,9	19,7	-2,2	27,2

Table 52: Investments [MW]

	Competitive Setting								Strategic Setting							
	CH North				CH South				CH North				CH South			
	Gas	Bio	Wind	Solar	Gas	Bio	Wind	Solar	Gas	Bio	Wind	Solar	Gas	Bio	Wind	Solar
2015		891	987	2937						891	1098	2557				
2020		9		1605						9		1497				
2025		14		1413			29			14		1564				
2030		23		1799			204			23		1802				
2035		45		2153			224			45		2125				
2040		891	563	10843		818	204			891	720	6117			7	
2045		9		1605						9	192	3039			47	
2050		14								14		1980			47	

Table 53: Generation Capacities [GW]

	Competitive Setting								Strategic Setting							
	CH North				CH South				CH North				CH South			
	Gas	Bio	Wind	Solar	Gas	Bio	Wind	Solar	Gas	Bio	Wind	Solar	Gas	Bio	Wind	Solar
2015		1,0	1,0	2,9		0,1	0,0	1,4		1,0	1,2	2,6		0,1		1,4
2020		1,0	1,0	4,5		0,1		1,2		1,0	1,1	4,1		0,1		1,2
2025		1,0	1,0	6,0		0,1		1,0		1,0	1,1	5,6		0,1		1,0
2030		1,0	1,0	7,8			0,2	0,7		1,0	1,1	7,4				0,7
2035		1,0	1,0	9,9			0,5			1,0	1,1	9,5				
2040		1,0	0,6	17,8		0,8	0,7			1,0	0,7	13,1				
2045		1,0	0,6	17,8		0,8	0,7			1,0	0,9	14,6			0,1	
2050		1,0	0,6	16,4		0,8	0,6			1,0	0,9	15,1			0,1	

Capacity Market + Quota Framework, Single Zone

Table 54: Energy Market Prices [€/MWh]

	Competitive Setting					Strategic Setting				
	CH	DE	FR	AT	IT	CH	DE	FR	AT	IT
2015	30,3	30,6	29,4	30,5	31,6	31,3	30,8	29,4	31,0	31,7
2020	40,5	40,4	38,6	40,1	43,8	42,1	41,0	38,6	40,8	43,9
2025	53,1	52,7	48,6	52,7	53,3	54,4	52,9	48,6	53,2	54,0
2030	67,7	68,1	65,7	67,9	68,2	69,1	68,5	65,8	68,4	69,1
2035	77,3	77,1	76,2	76,3	79,6	80,4	78,5	76,6	77,3	81,3
2040	88,5	88,2	88,7	88,0	89,3	90,3	89,5	90,0	88,8	90,7
2045	98,0	97,2	98,4	96,7	98,7	99,9	98,6	99,8	97,2	100,3
2050	103,7	102,7	103,7	101,3	104,8	106,2	104,4	105,3	102,1	106,9

Table 55: Swiss Market Conditions [TWh], Capacity Price [€/kW], Quota [€/MWh]

	Competitive Setting					Strategic Setting				
	Demand	Supply	Imp/Exp	Cap	Quota	Demand	Supply	Imp/Exp	Cap	Quota
2015	65,2	68,9	3,7	0	0.0	64,9	62,6	-2,3	0	0.0
2020	64,2	66,4	2,2	131	0.0	63,8	58,0	-5,7	0	16.4
2025	63,2	62,4	-0,8	105	0.0	63,0	57,7	-5,3	0	33.9
2030	63,1	62,2	-0,9	587	40.2	62,8	55,0	-7,8	1007	183.6
2035	63,8	70,6	6,9	88	0.0	63,2	50,5	-12,6	0	53.6
2040	64,5	76,7	12,2	0	15.4	64,2	54,5	-9,6	0	45.1
2045	65,7	80,8	15,1	35	0.0	65,2	58,7	-6,5	0	65.4
2050	66,6	85,4	18,8	0	0.0	66,1	59,6	-6,4	0	80.2

Table 56: Investments [MW]

	Competitive Setting				Strategic Setting			
	Gas	Biomass	Wind	Solar	Gas	Biomass	Wind	Solar
2015							38	
2020	2676		190		2633		291	
2025	561		327		483		577	
2030	628	628	268		779	274	502	
2035	806	1172			559	1526	71	
2040			22	3139				5466
2045	1777		262	4353	1958		92	1301
2050			508	7393	562		507	836

Table 57: Generation Capacities [GW]

	Competitive Setting						Strategic Setting					
	Hydro	Nuc	Gas	Bio	Wind	Solar	Hydro	Nuc	Gas	Bio	Wind	Solar
2015	17.5	3.33	0,0	0,2	0,1	1,4	17.5	3.33	0,0	0,2	0,1	1,4
2020	17.5	2.97	2,7	0,1	0,2	1,3	17.5	2.97	2,6	0,1	0,4	1,3
2025	17.5	2.23	3,2	0,1	0,6	1,0	17.5	2.23	3,1	0,1	1,0	1,0
2030	17.5	1.22	3,9	0,7	0,8	0,7	17.5	1.22	3,9	0,4	1,4	0,7
2035	17.5		4,7	1,8	0,8		17.5		4,5	1,8	1,5	
2040	17.5		4,7	1,8	0,8	3,1	17.5		4,5	1,8	1,4	5,5
2045	17.5		3,8	1,8	0,9	7,5	17.5		3,8	1,8	1,2	6,8
2050	17.5		3,2	1,8	1,1	14,9	17.5		3,9	1,8	1,2	7,6

Capacity Market + FIP Framework, Single Zone

Table 58: Energy Market Prices [€/MWh]

	Competitive Setting					Strategic Setting				
	CH	DE	FR	AT	IT	CH	DE	FR	AT	IT
2015	30,3	30,6	29,3	30,5	31,6	31,3	30,8	29,4	31,0	31,7
2020	40,5	40,4	38,6	40,1	43,8	42,5	41,2	38,6	40,8	43,9
2025	53,1	52,7	48,6	52,7	53,3	54,7	53,0	48,6	53,4	54,2
2030	68,0	68,2	65,8	68,0	68,4	69,9	68,9	65,9	68,9	69,7
2035	77,3	77,1	76,2	76,3	79,6	81,7	79,4	76,8	78,1	82,6
2040	88,6	88,3	88,8	88,1	89,4	91,4	90,4	90,8	89,4	91,7
2045	98,0	97,2	98,4	96,6	98,7	101,2	99,6	100,8	97,8	101,4
2050	103,7	102,7	103,7	101,2	104,8	107,5	105,5	106,4	102,8	108,2

Table 59: Swiss Market Conditions [TWh], Capacity Price [€/kW], FIP [€/MWh]

	Competitive Setting					Strategic Setting				
	Demand	Supply	Imp/Exp	Cap	FIP	Demand	Supply	Imp/Exp	Cap	FIP
2015	65,2	69,1	3,9	0		64,9	62,5	-2,4	0	
2020	64,2	67,0	2,8	166	40	63,7	56,3	-7,4	0	40
2025	63,2	62,5	-0,7	105	30	62,9	55,2	-7,8	0	30
2030	63,0	60,1	-3,0	552	20	62,7	48,7	-13,9	1007	20
2035	63,8	70,5	6,8	88	10	62,9	37,2	-25,6	0	10
2040	64,5	74,8	10,3	0		63,9	38,1	-25,8	0	
2045	65,7	81,3	15,7	70		64,9	41,3	-23,6	0	
2050	66,6	86,2	19,6	0		65,8	41,7	-24,0	0	

Table 60: Investments [MW]

	Competitive Setting				Strategic Setting			
	Gas	Biomass	Wind	Solar	Gas	Biomass	Wind	Solar
2015			91					
2020	2588		379		2736			
2025	644		63		655		28	
2030	1094		51		1103		21	
2035	384	1800	77		1543		24	
2040			164	1486	167		57	
2045	1282		596	8087	2891		118	
2050			332	7801	722	115	152	103

Table 61: Generation Capacities [GW]

	Competitive Setting						Strategic Setting					
	Hydro	Nuc	Gas	Bio	Wind	Solar	Hydro	Nuc	Gas	Bio	Wind	Solar
2015	17.5	3.33	0,0	0,2	0,2	1,4	17.5	3.33	0,0	0,2	0,1	1,4
2020	17.5	2.97	2,6	0,1	0,5	1,3	17.5	2.97	2,7	0,1	0,1	1,3
2025	17.5	2.23	3,2	0,1	0,6	1,0	17.5	2.23	3,4	0,1	0,1	1,0
2030	17.5	1.22	4,3	0,1	0,6	0,7	17.5	1.22	4,5	0,1	0,1	0,7
2035	17.5		4,7	1,8	0,7		17.5		6,0		0,1	
2040	17.5		4,7	1,8	0,7	1,5	17.5		6,2		0,1	
2045	17.5		3,4	1,8	1,0	9,6	17.5		6,4		0,2	
2050	17.5		2,8	1,8	1,2	17,4	17.5		6,4	0,1	0,4	0,1