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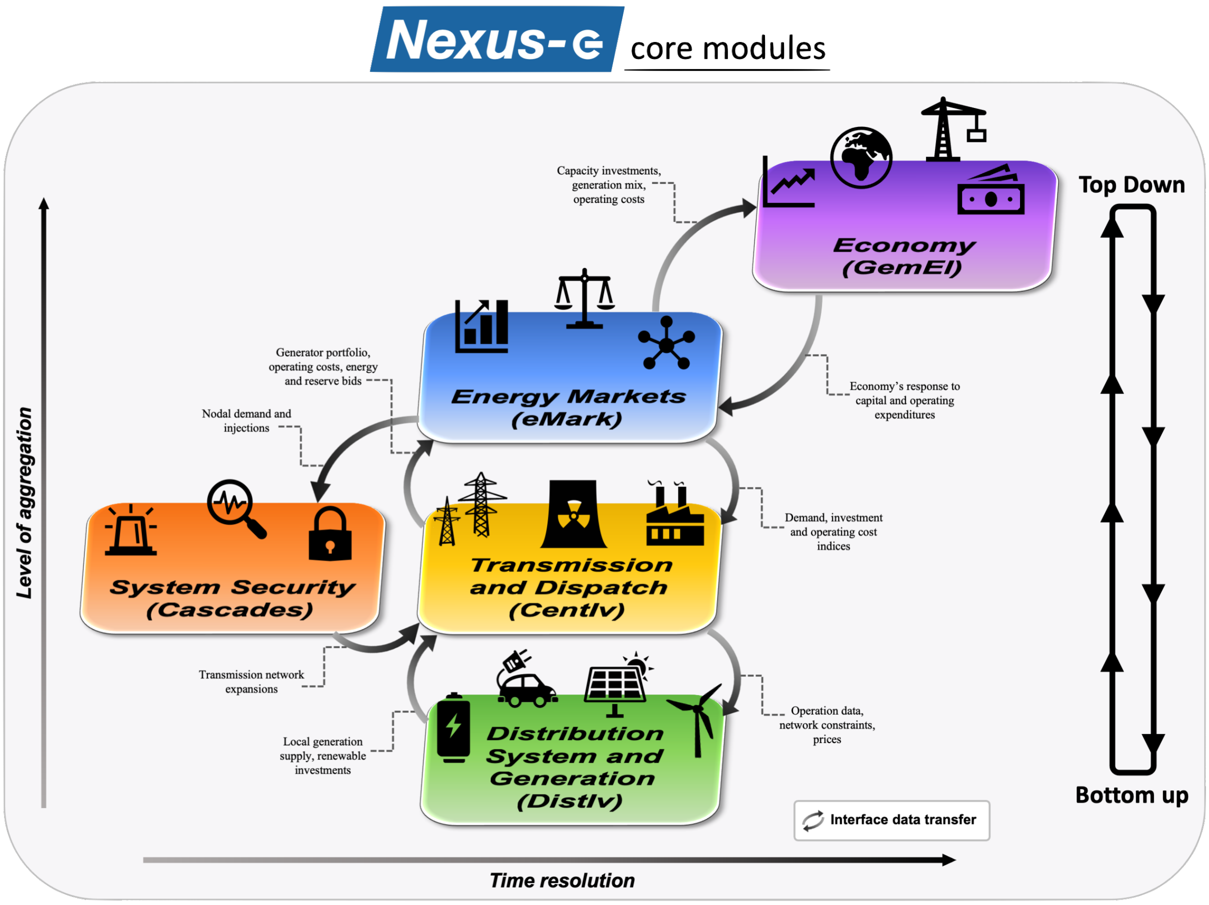
Final report

Nexus-e: Integrated Energy Systems Modeling Platform

eMark Module Documentation



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Summary

Policy changes in the energy sector result in wide-ranging implications throughout the entire energy system and influence all sectors of the economy. Due partly to the high complexity of combining separate models, few attempts have been undertaken to model the interactions between the components of the energy-economic system. The Nexus-e Integrated Energy Systems Modeling Platform aims to fill this gap by providing an interdisciplinary framework of modules that are linked through well-defined interfaces to holistically analyze and understand the impacts of future developments in the energy system. This platform combines bottom-up and top-down energy modeling approaches to represent a much broader scope of the energy-economic system than traditional stand-alone modeling approaches.

In Phase 1 of this project, the objective is to develop a novel tool for the analysis of the Swiss electricity system. This study illustrates the capabilities of Nexus-e in answering the crucial questions of how centralized and distributed flexibility technologies could be deployed in the Swiss electricity system and how they would impact the traditional operation of the system. The aim of the analysis is not policy advice, as some critical developments like the European net-zero emissions goal are not yet included in the scenarios, but rather to illustrate the unique capabilities of the Nexus-e modeling framework. To answer these questions, consistent technical representations of a wide spectrum of current and novel energy supply, demand, and storage technologies are needed as well as a thorough economic evaluation of different investment incentives and the impact investments have on the wider economy. Moreover, these aspects need to be combined with modeling of the long- and short-term electricity market structures and electricity networks.

The Nexus-e Platform consists of five interlinked modules:

1. General Equilibrium Module for Electricity (GemEl): a computable general equilibrium (CGE) module of the Swiss economy,
2. Centralized Investments Module (CentIv): a grid-constrained generation expansion planning (GEP) module considering system flexibility requirements,
3. Distributed Investments Module (DistIv): a GEP module of distributed energy resources,
4. Electricity Market Module (eMark): a market-based dispatch module for determining generator production schedules and electricity market prices,
5. Network Security and Expansion Module (Cascades): a power system security assessment and transmission system expansion planning module.

This report provides the description and documentation for the eMark module, which is utilized in the Nexus-e framework to provide a market-based dispatch of generators that better reflects the actual procedures currently used to clear the energy and reserve markets as well as the timing of the various market products and the coupling of market zones.

Zusammenfassung

Politische Veränderungen im Energiesektor haben weitreichende Auswirkungen auf das gesamte Energiesystem und beeinflussen alle Sektoren der Wirtschaft. Aufgrund der hohen Komplexität der Energiewirtschaft, wurden bisher nur wenige Versuche unternommen, die Wechselwirkungen zwischen den einzelnen Komponenten dieses Systems zu modellieren. Nexus-e, eine Plattform für die Modellierung von integrierten Energiesystemen, schliesst diese Lücke und schafft einen interdisziplinäre Plattform, in welcher verschiedene Module über klar definierten Schnittstellen miteinander verbunden sind. Dadurch können die Auswirkungen zukünftiger Entwicklungen in der Energiewirtschaft ganzheitlicher analysiert und verstanden werden. Die Nexus-e Plattform ermöglicht die Kombination von „Bottom-Up“ und „Top-Down“ Energiemodellen und ermöglicht es dadurch, einen breiteren Bereich der Energiewirtschaft abzubilden als dies bei traditionellen Modellierungsansätzen der Fall ist.

Phase 1 dieses Projekts zielt darauf ab, ein neuartiges Instrument für die Analyse des schweizerischen Elektrizitätssystems zu entwickeln. Um die Möglichkeiten von Nexus-e zu veranschaulichen, untersuchen wir die Frage, wie zentrale und dezentrale Flexibilitätstechnologien im schweizerischen Elektrizitätssystem eingesetzt werden können und wie sie sich auf den traditionellen Betrieb des Energiesystems auswirken würden. Ziel der Analyse ist es nicht Empfehlungen für die Politik zu geben, da einige wichtige Entwicklungen wie das Europäische Netto-Null-Emissionsziel noch nicht in den Szenarien enthalten sind. Vielmehr möchten wir die einzigartigen Fähigkeiten der Modellierungsplattform Nexus-e vorstellen. Um diese Fragen zu beantworten, ist eine konsistente technische Darstellungen aktueller und neuartiger Energieversorgungs-, Nachfrage- und Speichertechnologien, sowie eine gründliche wirtschaftliche Bewertung der verschiedenen Investitionsanreize und der Auswirkungen der Investitionen auf die Gesamtwirtschaft erforderlich. Darüber hinaus müssen diese Aspekte mit der Modellierung der lang- und kurzfristigen Strommarktstrukturen und Stromnetze kombiniert werden.

Die Nexus-e Plattform besteht aus fünf miteinander verknüpften Modulen:

1. Allgemeines Gleichgewichtsmodul für Elektrizität (GemEl): ein Modul zur Darstellung des allgemeinen Gleichgewichts (CGE) der Schweizer Wirtschaft,
2. Investitionsmodul für zentrale Energiesysteme (CentIv): ein Modul zur Planung des netzgebundenen Erzeugungsausbaus (GEP) unter Berücksichtigung der Anforderungen an die Systemflexibilität,
3. Investitionsmodul für dezentrale Energiesysteme (DistIv): ein GEP-Modul für dezentrale Energieerzeugung,
4. Strommarktmodul (eMark): ein marktorientiertes Dispatch-Modul zur Bestimmung von Generator-Produktionsplänen und Strommarktpreisen,
5. Netzsicherheits- und Erweiterungsmodul (Cascades): ein Modul zur Bewertung der Sicherheit des Energiesystems und zur Planung der Erweiterung des Übertragungsnetzes.

Dieser Bericht beinhaltet die Beschreibung und Dokumentation des eMark-Moduls. Dieses Modul wird im Rahmen von Nexus-e verwendet, um eine marktorientierte Einspeisung von Stromerzeugern zu ermöglichen, die die aktuellen Verfahren zur Abwicklung der Energie- und Reservemärkte sowie das Timing der verschiedenen Marktprodukte und die Kopplung von Marktzonen besser widerspiegelt.

Résumé

Les changements de politique dans le secteur de l'énergie ont de vastes répercussions sur l'ensemble du système énergétique et influencent tous les secteurs de l'économie. En partie à cause de la grande complexité de la combinaison de modèles séparés, peu de tentatives ont été entreprises pour modéliser les interactions entre les composantes du système économico-énergétique. La plateforme de modélisation des systèmes énergétiques intégrés Nexus-e vise à combler cette lacune en fournissant un cadre interdisciplinaire de modules qui sont reliés par des interfaces bien définies pour analyser et comprendre de manière holistique l'impact des développements futurs du système énergétique. Cette plateforme combine des approches de modélisation énergétique ascendante et descendante pour représenter un champ d'application beaucoup plus large du système économico-énergétique que les approches de modélisation indépendantes traditionnelles.

Dans la phase 1 de ce projet, l'objectif est de développer un nouvel outil pour l'analyse du système électrique suisse. Cette étude sert à illustrer les capabilités de Nexus-e à répondre aux questions cruciales de comment les technologies de flexibilité centralisées et décentralisées pourraient être déployées dans le système électrique suisse et comment elles affecteraient le fonctionnement traditionnel du système. Le but de cette analyse n'est pas d'offrir de conseils politiques, en tant que les scénarios ne considèrent pas des développements critiques comme l'objectif Européen d'atteindre zéro émission nette, mais d'illustrer les capabilités uniques de la plateforme Nexus. Pour répondre à ces questions, des représentations techniques cohérentes d'un large éventail de technologies actuelles et nouvelles d'approvisionnement, de demande et de stockage d'énergie sont nécessaires, ainsi qu'une évaluation économique approfondie des différentes incitations à l'investissement et de l'impact des investissements sur l'économie au sens large. En outre, ces aspects doivent être combinés avec la modélisation des structures du marché de l'électricité et des réseaux d'électricité à long et à court terme.

La plateforme Nexus-e se compose de cinq modules interconnectés:

1. Module d'équilibre général pour l'électricité (GemEl) : un module d'équilibre général calculable (CGE) de l'économie suisse,
2. Module d'investissements centralisés (CentIv) : un module de planification de l'expansion de la production (GEP) soumise aux contraintes du réseau, qui tient compte des exigences de flexibilité du système,
3. Module d'investissements distribués (DistIv) : un module GEP de la production décentralisée d'énergie,
4. Module du marché de l'électricité (eMark) : un module de répartition basé sur le marché pour déterminer les calendriers de production des producteurs et les prix du marché de l'électricité,
5. Module de sécurité et d'expansion du réseau (Cascades) : un module d'évaluation de la sécurité du système électrique et de planification de l'expansion du système de transmission.

Ce rapport fournit la description et la documentation du module eMark, qui est utilisé dans le cadre de Nexus-e pour fournir une répartition des producteurs basée sur le marché qui reflète mieux les procédures réelles actuellement utilisées pour compenser les marchés de l'énergie et des réserves ainsi que le calendrier des différents produits du marché et le couplage des zones de marché.

Contents

Abbreviations

AC	alternating current
ACER	Agency for the Cooperation of Energy Regulators
AT	Austria
ATC	available transfer capacity
BaM	balancing market
BSS	battery storage system
Cascades	Network Security and Expansion Module
CentIv	Centralized Investments Module
CGE	computable general equilibrium
CH	Switzerland
CREG	Belgian Federal Commission for Electricity and Gas Regulation
CWE	Central Western Europe
D2CF	two-day-ahead congestion forecast
DaM	day-ahead market
DC	direct current
DE	Germany
DistIv	Distributed Investments Module
DSM	demand-side management
EEX	European Energy Exchange
eMark	Electricity Market Module
EMP-E	Energy Modeling Platform for Europe
ENTSO-E	European Network of Transmission System Operators for Electricity
EPEX	European Power Exchange
FB	flow-based
FCR	frequency containment reserve
FR	France
FRM	flow reliability margin
FRR	frequency restoration reserve
FuM	future market
GemEl	General Equilibrium Module for Electricity
GEP	generation expansion planning
GSK	generation shift keys
IT	Italy
LP	linear programming
LTC	long-term transfer capacity
MCP	market clearing price
MILP	mixed-integer linear programming
MVA	mega-volt ampere
MW	megawatt
MWh	megawatt hour
NEMO	Nominated Electricity Market Operator
NTC	net transfer capacity
OM	operation and maintenance
OTC	over-the-counter
PTDF	power transfer distribution factor

PV	photovoltaic
PWA	piece-wise affine
RES	renewable energy source
RoR	run of river
TSO	transmission system operator

List of Figures

List of Tables

1 Introduction

1.1 Module purpose

The purpose of the eMark module is to simulate a market-based clearing of electricity and reserve supply offers and demand bids. This module is designed to mimic the actual sequential structures and timing currently employed to clear all electricity market products. Additionally, eMark is setup to apply realistic constraints for intra-zonal trading that reflect the current market coupling mechanisms. In this work, the eMark model is applied to a subset of the European Network of Transmission System Operators for Electricity (ENTSO-E) network consisting of Switzerland (CH), Germany (DE), France (FR), Italy (IT), and Austria (AT) with a specific focus on Switzerland. The module is structured to provide high temporal (hourly) resolution and moderate spatial (zonal) resolution equivalent to those of the existing market processes. eMark has the important role in the Nexus-e framework to provide a market-based perspective and enable assessments of future market structures.

1.2 Process overview

The eMark module simulates the energy and reserve market clearing over a one year period using an hourly resolution. In three sequential steps, the model simulates the clearing of the future market, balancing market, and day-ahead market. First, the future market is cleared for a one month period where a user-defined fraction of the average hourly zonal demand during this month is supplied during all hours (i.e. the demand in the future clearing is constant over all hours of one month). Second, the balancing market is cleared for the first week of the same month where all required reserves are supplied over this week (similarly, each reserve requirement is constant over all hours of one week). Third, the day-ahead market is cleared for each hour of the first day of the same week where all remaining electricity demand not already cleared in the future market is supplied in each hour. The day-ahead clearing is repeated for each day of the week followed by repeating of the balancing and day-ahead market clearing for the next weeks and later the future market clearing for the next month. This sequential process continues until each day, week and month are completed.

1.3 Attributes

The following list characterises some of the main module attributes:

- Hourly resolution spanning one year
- Coded in Matlab, utilizing functions of the MatPower package and Gurobi solver
- Linear optimization problems (uniform auctions) for clearing each market
- Deterministic solution (no uncertainty considered in hourly demand or non-dispatchable injections)
- Zonal-based clearing with inter-zonal trade limits
- Reduction to zonal network using nonlinear optimization
- Flexible/modular structure that can be adapted for different market structures and timings
- Automatic import of input data from MySQL database
- Robust and automated interfaces to other Nexus-e modules and update of associated interface input data in eMark

1.4 Capabilities

The following list describes some of the main capabilities of this module:

- Market-based generator scheduling decisions
- Sequential modeling of future market (FuM), balancing market (BaM), and day-ahead market (DaM) clearings
- Multiple zonal market coupling mechanisms: available transfer capacity (ATC)-based, flow-based (FB), mixed
- Endogenously priced and cleared imports and exports between modeled market zones

1.5 Limitations

The following list provides context on some of the main limitations of eMark:

- Treatment of Hydro Dams and Hydro Pumps is limited because future knowledge is not considered in any individual hourly clearing.
- Modeling of reservoirs does not include the full hydrological network and connections between reservoirs and hydro generators.
- Both frequency restoration reserve (FRR) reserve products (i.e. secondary and tertiary reserves) are modeled as a single product.
- No redispatch process is used to translate the market-based clearing into a dispatch that ensures no intra-zonal transmission network violations.
- Hydro pumps currently are not enabled to participate in the reserve markets.
- No nuclear refueling schedules are accounted for.
- No generator ramp limits are considered during the electricity dispatch or reserve procurements.
- No load shedding is allowed.

1.6 Inputs and outputs

Tables 1 and 2 below list the eMark module's required input data and resulting output data. Those data that are input from or sent to another module through an interface are noted with an asterisks (*). It is important to note that all input data are pulled from a dedicated MySQL database that is also used by the other Nexus-e modules. This common datasource contributes to increase consistency and transparency among the modules.

Table 1: Listing of required input data for the eMark module.

Data	Resolution	Unit	Description
Generator data*	by unit	various	Location, capacity, costs, operational parameters, etc.
Grid Topology	–	various	Detailed transmission network data (buses, branches, transformers)
Demand*	hourly, nodal	MW	Nodal hourly transmission system demand
Renewable power injections	hourly, by unit	MW	Hourly production profiles for hydro-run of river (RoR), wind, and photovoltaic (PV) units
Reserve requirements*	hourly, zonal	MW	Hourly zonal frequency containment reserve (FCR) and FRR requirements
Gen hedge ratios	by unit	fraction	Hedge ratios used to calculate the generator capacities that participate in the FuM clearing
Load hedge ratios	nodal	fraction	Hedge ratios used to calculate the demand required in the FuM clearing
Hydro generator data	by unit	various	Additional generator data for hydro units: pump capacity, charge/discharge efficiency
Hydro reservoir data	by unit	MWh	Max storage volume, initial storage volume, hourly natural inflows
Hydro dam monthly levels*	monthly	MWh	Month-ending storage volume levels for hydro dam units
Inter-zonal coupling type	by connected zones	–	Defines all zonal connections and the type of market coupling used for each
NTC limits	by connected zones	MW	Maximum net transfer capacity (NTC) trade limit between each zonal coupling
LTC limits	by connected zones	MW	Maximum long-term transfer capacity (LTC) trade limit between each zonal coupling

Table 2: Listing of resulting output data for the eMark module.

Data	Resolution	Unit	Description
Electricity market clearings	hourly, by unit	MWh	FuM and DaM clearings for electricity production
Reserve market clearings	hourly, by unit	MW	BaM clearings for FCR and FRR
Overall generator schedules*	hourly, by unit	MWh	Total generator production levels
Electricity Prices	hourly, zonal	Euro/MWh	Market clearing prices of FuM and DaM
Reserve Price	hourly, zonal	Euro/MWh	Market clearing prices of FCR and FRR
Generator operating costs*	hourly, by unit	Euro	Incurred operating expenses for generators
Inter-zonal trade	hourly, by connected zone	MWh	Amount of power traded across zones during market clearings
Import and export flows	hourly, by connected zone	MWh	Actual resulting power flows across zones
Branch flows	hourly, by branch	MW	Actual line flows in the full detailed network
Generator capacity allocation	hourly, by unit	MW	Breakdown of available, unavailable, used, unused, generator capacities
Hydro pump charging	hourly, by unit	MWh	Electricity consumption from hydro pump units
Hydro storage levels	hourly, by unit	MWh	Reservoir storage levels
Production costs	hourly, zonal	Euro	Sum of the generation costs of of all dispatched generating units
Consumer costs	hourly, zonal	Euro	Sum of the payments made to all generating units
Producer surplus	hourly, zonal	Euro	Sum of the profits made by all generating units
Congestion rent	hourly, zonal	Euro	Sum of the additional earnings from exporting to a zone with a higher clearing price

2 Related work and contributions

2.1 European market structure

By introducing liberalized electricity markets, energy costs on the wholesale level have decreased over the years. This is due to the competition that market players face and the transparency that markets establish. Currently, there are three market types that are active around Europe. For each market type the network codes [1, 2, 3] were specified from ENTSO-E that the European Commission put into force and serve as a legal framework for the European transmission system operators (TSOs)). As depicted in Fig. 1 the following markets[1] exist in European Countries:

Figure 1: Current market structure in Europe [4].

Forward Markets are markets where consumers or producers can buy or sell long-term contracts. This market is intended to hedge the price risk against decreasing/increasing prices for producers and consumers. Contracts can be traded over-the-counter (OTC) or over clearing houses. To ensure transparency and eliminate the counter party risk, standardized forward contracts (futures) are traded over future exchanges such as the European Energy Exchange (EEX). Futures specify a certain delivery period and the amount of energy to be delivered in this period and their underlying is the spot market price. In Europe, base and peak products are available. Cross-border trading can be realized by yearly or monthly transmission rights auctions.

Day-ahead and Intraday Markets are auction-based spot markets in which buy and sell orders are composed into demand and supply curves. The market is cleared by matching the supply and demand curve. The intersection of the curves determines the market clearing price (MCP). In Europe, the European Power Exchange (EPEX) spot markets are established for different market zones. A three-stage optimization problem is solved [5] to clear the market. This allows the consideration of complex orders. Finally, cross-border trading can be realized by either implicit or explicit transmission rights auctions.

Balancing Markets are run by the TSOs to support the grid security. Each TSO procures balancing capacity to make the power system secure against load and generation forecast errors and contingencies by using pay as bid auctions. There is a three-stage operating scheme that protects and restores the system from such events. Each stage represents a service that is put on the market and can also be traded across the border.

[1] All market types use auction-based clearing techniques that will be described in Section 3.1.

2.2 Literature review

Related to the introduced European market structure, the following sources were instrumental in developing the methodology employed in the eMark module:

- The book by Skantze and Ilic [6] conveys the fundamental differences between electricity and other traded commodities, and the impact these differences have on valuation, hedging and operational decisions made by market participants. The optimization problems associated with these decisions are formulated in the context of the market realities of today's power industry, including a lack of liquidity on forward and options markets, limited availability of historical data, and constantly changing regulatory structures.
- The report from the Nominated Electricity Market Operator (NEMO) committee [7] provides background details on the difference between ATC and FB market coupling mechanisms along with details of market orders (complex orders, block orders, and merit orders). The welfare maximization problem is also presented in detail.
- The documentation from a group of European TSOs and power exchanges [5] explains the basics of FB market coupling along with a compiled explanation for how 'intuitive' FB works.
- The journal paper by Bergh [8] presents a thorough description of the FB market coupling concepts and definitions currently used in the Central Western Europe (CWE) region of Europe. The aim to for this detail to serve as a starting point for further research into the methodology and its market impact.
- The feasibility report from a group of European TSOs and power exchanges [9] is the first report detailing the development, evaluation, and improvements made over an eight year period when the FB market coupling for the CWE region was being created. It includes a feasibility report for the FB operation based on experimentation with the 2011 conditions.
- A report by Belgian Federal Commission for Electricity and Gas Regulation (CREG) [10] provides evidence-based criticism related to concerns raised by national regulators, Agency for the Cooperation of Energy Regulators (ACER) and numerous other stakeholders. The report assesses the impact of discretionary actions taken by TSOs on the design and the functioning of the CWE DaM FB market coupling.

3 Detailed module description

This Section details the modeling aspects and algorithms that are used within the eMark module for the Nexus-e project. Section 3.1 introduces the basic concepts to describe market clearings and simplifies them to achieve tractable formulations. This is important, since we aim to simulate markets that may consist of a large number of buyers, sellers, buses, lines, and coupled market zones. Next, Section 3.2 presents the optimization framework created to model a sequential set of markets that are connected to other market zones with a similar set of sequential markets. Section 3.3 then describes how these sequential markets are coupled together to mimic the timing of the existing market structure along with the heuristics used to enable modeling of storages that follow seasonal (hydro dams) and daily (hydro pumps) cycles.

3.1 Market clearing

Under the assumption of optimal market operation, we can use the approach of production (cost) based market modeling as introduced in [6]. In principle, this means that the electricity prices are determined by matching marginal cost curves of supply offers with demand bid cost curves.

3.1.1 Modeling of auctions

The fundamental goal of an electricity market auction is to maximize social welfare which includes the consumer surplus, supplier surplus, and the congestion rent. For uniform auctions, this is done over power exchanges that collect generation sell offers defined by quantity Q_s^z and price per quantity P_s^z and consumption buy bids defined analogously with Q_b^z, P_s^z in a given market zone z and clear the market by solving the following optimization problem:

$$\begin{aligned} \text{social welfare } J^* = \quad & \max_{\vec{x}_s, \vec{x}_b} \sum_{z \in Z} \left(\sum_{b \in B} x_b^z Q_b^z P_b^z - \sum_{s \in S} x_s^z Q_s^z P_s^z \right) \\ & \text{s.t.} \\ & \text{(a)} \quad \sum_{s \in S} x_s^z Q_s^z - \sum_{b \in B} x_b^z Q_b^z + p_{\text{net}}^z = 0 \; \forall z \\ & \text{(b)} \quad p_l = f(p_z) \; \forall l \\ & \text{(c)} \quad \underline{p}_l \leq p_l \leq \overline{p}_l \; \forall l \quad . \end{aligned} \tag{1}$$

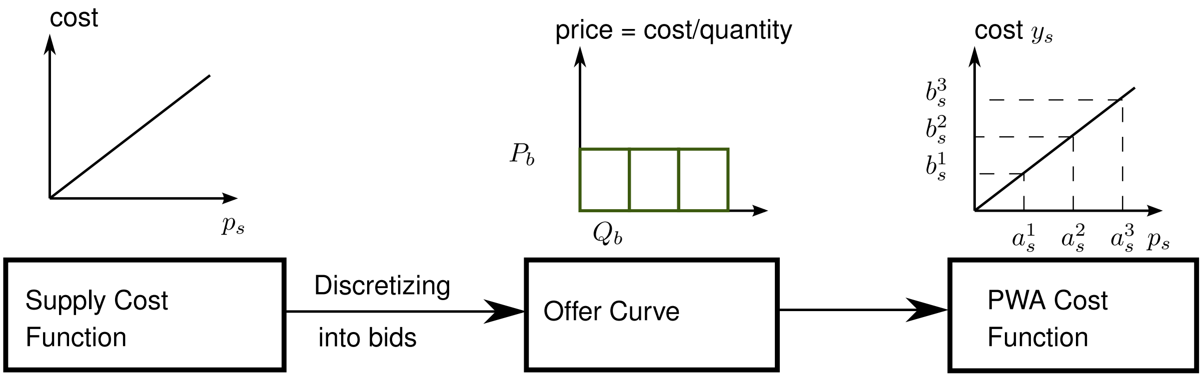
The objective is to maximize the sum of all buy orders and sell orders over all market zones Z. As discussed in [7] this is equivalent to maximizing the social welfare. The optimization problem (1) is a mixed-integer linear programming (MILP), since the decision variables $\vec{x}_s, \vec{x}_b$ are binary, reflecting the binary status of accepted buy and sell orders [5]. It is also allowed with the equality (1a) to export/import energy indicated by p_{net}^z to/from other market zones. The equality (1b) translates the zonal imports/exports to power flows p_l between the anticipated market zones. The zonal exchanges are limited (1c) and can be constrained in different ways (such as an ATC-based or FB limit).

3.1.2 Continuous offers

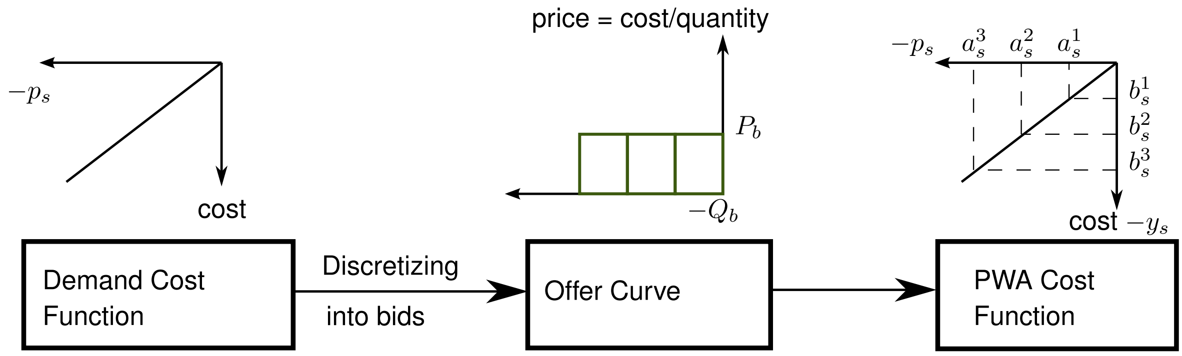
In eMark, problem (1) is translated into a less complex linear programming (LP) problem at the cost of loosing the discretized generation set points corresponding to the specific offer quantities and prices of each generator. Instead, the LP converts the set of offer/price quantities into cost functions. This step is useful to reduce computational complexity. The simplified problem is:

$$
\begin{aligned}
\text{social welfare } J^* = \quad & \max_{\vec{y}_s, \vec{y}_b, \vec{p}_b, \vec{p}_s} \sum_{z \in Z} \left(\sum_{b \in B} y_b^z - \sum_{s \in S} y_s^z \right) \\
& \text{s.t.} \\
& \text{(a)} \quad \sum_{s \in S} p_s^z - \sum_{b \in B} p_b^z + p_z = 0 \ \forall z \\
& \text{(b)} \quad p_l = f(p_z) \ \forall l \\
& \text{(c)} \quad \underline{p}_l \le p_l \le \overline{p}_l \ \forall l \\
& \text{(d)} \quad \vec{a}_s^z p_s^z - y_s^z \ge \vec{b}_s^z \ \forall z, s \\
& \text{(e)} \quad \vec{a}_b^z p_b^z - y_b^z \ge \vec{b}_b^z \ \forall z, b \quad ,
\end{aligned}
\tag{2}
$$

where y_s^z, y_b^z are auxiliary variables that together with constraints (2d,e) represent piece-wise affine (PWA) cost functions. As shown in Fig. 2a, we discretize generator cost functions into discrete offer curves. From these representations, we create their PWA counterparts that can be incorporated into a less complex LP clearing.



(a) Supply offer modeling. Any convex cost function is discretized into offers that are further processed into a PWA cost function. In this way, the MILP problem can be translated in a less complex LP clearing problem.



(b) Elastic demand bid modeling. Inclusion of elastic demands, such as charging of storage devices, is modeled in the same way as shown as in Fig. 2a except that the supply offers have a negative cost function.

Figure 2: Modeling of offer curves that are incorporated as PWA cost functions in the clearing problems.

3.1.3 Inelastic demand

If the entire demand has to be supplied under all circumstances, the demand curve is said to be inelastic. In this case, any associated demand bid has to be executed. This assumption can be viewed as a consumer willing to pay an infinite price to supply its demand. Incorporation of such an inelastic demand can be described as follows:

$$
\begin{aligned}
J^* = \quad & \min_{\vec{y}_s, \vec{p}_s} \sum_{z \in Z} \sum_{s \in S} y_s^z \\
& \text{s.t.} \\
& \text{(a)} \quad \sum_{s \in S} p_s^z - p_d^z + p_z = 0 \ \forall z \\
& \text{(b)} \quad p_l = f(p_z) \ \forall l \\
& \text{(c)} \quad \underline{p}_l \leq p_l \leq \overline{p}_l \ \forall l \\
& \text{(d)} \quad \vec{a}_s^z p_s^z - y_s^z \geq \vec{b}_s^z \ \forall z, s \ ,
\end{aligned}
\tag{3}
$$

in which the demand bids are replaced by the fixed demand p_d^z. Note under this circumstance maximizing the social welfare corresponds to minimizing the total generation costs.

3.1.4 Elastic demand

Modeling an elastic demand curve is necessary if flexible units such as storage devices are in the system that can control their power demand. In this case, we can include this feature without changing the problem structure in the same clearing problem (3) by modeling these elastic demand bids as supply offers with negative quantities (see Fig. 2b).

3.1.5 Modeling of market zones and power flows

In this section we introduce a common model that maps the power flows from a detailed grid model to a zonal representation. The line flows $\vec{p}_{\mathsf{l}}$ of the detailed network with n_l lines, n_b buses, and n_g generators can be described by:

$$\vec{p}_{\mathsf{l}} = \vec{H}(\vec{C}_g \vec{p}_{\mathsf{g}} - \vec{p}_{\mathsf{d}}) \ , \tag{4}$$

where $\vec{H} \in \mathbb{R}^{n_l \times n_b}$ is the power transfer distribution factor (PTDF) matrix, $\vec{C}_g \in \mathbb{R}^{n_b \times n_g}$ is the generator to bus mapping matrix, $\vec{p}_{\mathsf{g}} \in \mathbb{R}^{n_g \times 1}$ represents the individual active generator power setpoints, and $\vec{p}_{\mathsf{d}} \in \mathbb{R}^{n_b \times 1}$ is the load vector of the detailed power system. While all market clearings will use a reduced zonal representation of the network (as described below), after any such clearing Equation(4) is used to compute the physical power flows within the detailed network.

To reflect certain price zones, the market clearing problem requires a zonal division with respect to the market participants. Considering n_z price zones, we define:

$$
\begin{aligned}
\vec{p}_{\mathsf{net}}^{\mathsf{z}} &= \vec{p}_{\mathsf{g}}^{\mathsf{z}} - \vec{p}_{\mathsf{d}}^{\mathsf{z}} &(5)\\
&= \vec{C}_{\mathsf{gz}} \vec{p}_{\mathsf{g}} - \vec{C}_{\mathsf{bz}} \vec{p}_{\mathsf{d}} \ , &(6)
\end{aligned}
$$

where $\vec{p}_{\mathsf{net}}^{\mathsf{z}} \in \mathbb{R}^{n_z \times 1}$ represents the zonal netpositions, $\vec{p}_{\mathsf{g}}^{\mathsf{z}} \in \mathbb{R}^{n_z \times 1}$ is the zonal aggregated generation and $\vec{p}_{\mathsf{d}}^{\mathsf{z}} \in \mathbb{R}^{n_z \times 1}$ is zonal demand. We couple the disaggregated generation and load with the generator to zone mapping matrix $\vec{C}_{\text{gz}} \in \mathbb{R}^{n_z \times n_g}$ and the load to zone mapping matrix $\vec{C}_{\text{bz}} \in \mathbb{R}^{n_z \times n_b}$ as shown in (6).

Under a purely ATC coupled market design, the zonal net positions can be expressed as a function of n_c crossborder exchanges $\vec{p}_{\text{t}} \in \mathbb{R}^{n_c \times 1}$ as follows:

$$\vec{p}^{\text{z}}_{\text{net}} = \vec{C}^{z}_{\text{ft}} \vec{p}_{\text{t}} \ , \tag{7}$$

where $\vec{C}^{z}_{\text{ft}} \in \mathbb{R}^{n_z \times n_c}$ is the contract path to zone mapping matrix.

FB market coupling allows better utilization of the total cross-border transmission capacity, since the flow approximations tend to be less conservative than the ATC values. To enable this coupling, a network reduction method is required that condenses the market zones to a smaller network model [11]. The transmission rights allocation is handled implicitly within the market clearing. The congestion rent is distributed to the TSOs by using the price differences between the market zones. At the moment only the CWE region is FB coupled. However, this might change and therefore we also have the possibility to have mixed configurations of ATC and FB market clearing.

In the FB market design, the generation shift keyss (GSKs) are needed to describe the impact of the individual generation setpoints on the zonal net position. The GSKs are determined by the TSO two days before (two-day-ahead congestion forecast (D2CF) base case [9]) and are estimated based on the predicted market outcome. Here, we map the $GSK \in \mathbb{R}^{n_b \times n_z}$ matrix directly with the zonal generation as follows:

$$\vec{C}_{\text{g}} \vec{p}_{\text{g}} \approx GSK \vec{p}^{\text{z}}_{\text{g}} \ . \tag{8}$$

By inserting the definitions (8) and (5) into (4) the expected line flows are:

$$\begin{aligned} \vec{p}_{\text{l}} &\approx \vec{H} \ GSK \ \vec{p}^{\text{z}}_{\text{g}} - \vec{H} \vec{p}_{\text{d}} && (9) \\ &\approx \vec{H} \ GSK \ (\vec{p}^{\text{z}}_{\text{net}} + \vec{p}^{\text{z}}_{\text{d}}) - \vec{H} \vec{p}_{\text{d}} && (10) \\ &\approx \vec{H} \ GSK \ \vec{p}^{\text{z}}_{\text{net}} + (\vec{H} \ GSK \vec{C}_{\text{bz}} - \vec{H}) \vec{p}_{\text{d}} \ . && (11) \end{aligned}$$

Equation (11) describes the impact of the zonal net position on the line flows and is needed to correctly represent the FBB domain [7, 8]. Note that in this formulation the D2CF base case is inherently considered, such we do not need to explicitly model the D2CF base case.

ENTSO-E is currently composed of numerous market zones with some ATC-based coupling and some FB coupling. eMark is structured to enable simulation of all ATC-based coupled market zones, all FB coupled market zones, and mixed ATC-based and FB coupled market zones. In this way, eMark will be able to reflect the current mixture of market coupling mechanisms as well as possible future enhancements.

3.1.6 Performance indicators

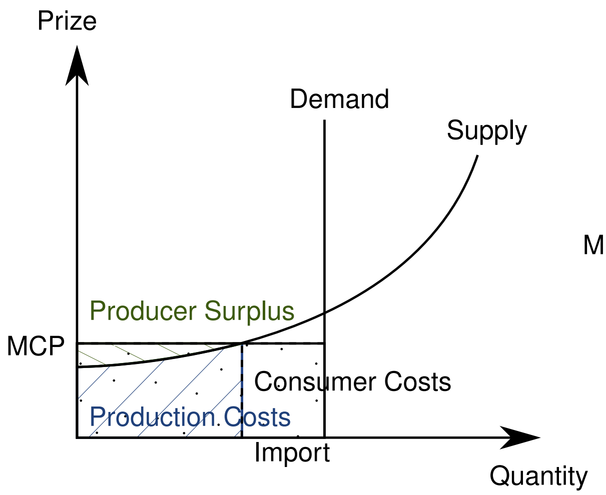
In this section we introduce different performance indicators that allow us to compare market designs. Figure 3 shows typical market clearings for one market zone in an import (a) and export (b) situation. In the illustrations the MCP is the cross section between the supply curve and the inelastic demand shifted around the zonal net position (import or export). For the comparisons we will use the production costs depicted as the blue shaded areas, the consumer costs shown as the black dotted areas and the production surplus illustrated with the green shaded areas. The congestion rent is not shown, but would be illustrated in Figure 3(b) by the total export quantity times the difference in the MCPs between the two zones (congestion rent is only non-zero when the congestion between the two zones results in a price difference between zones). The quantities are defined as follows:

The production costs of a given market zone are defined as the generation costs of all dispatched generation units. Note that the total production costs correspond to the overall social welfare if a) we sum up all generation costs over all market zones and b) we consider inelastic demands.

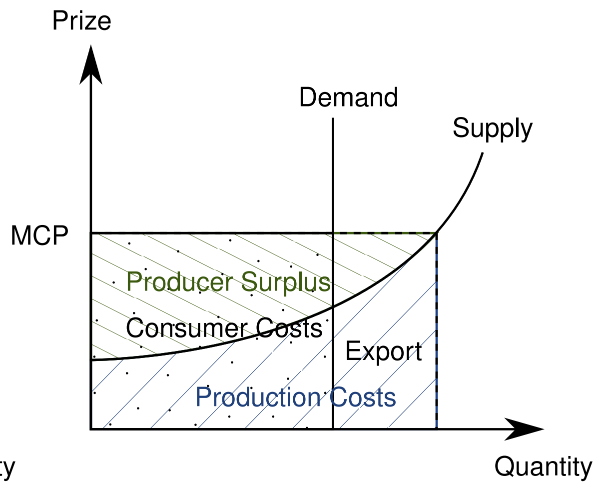
The consumer costs are defined as the zonal demand multiplied with the MCP and represent the total payments that are made to the operating generators.

The producer surplus corresponds to the profits earned by generators (revenue above operating costs) and is defined as the zonal power generation multiplied with the MCP minus the production costs.

The congestion rent is defined as the amount of export traded multiplied by the price difference between zones. This value represents the additional earnings one zone received from selling power to another zone that has a higher MCP.



(a) Import situation



(b) Export situation

Figure 3: Market clearing for one market zone in two situations. The MCP is the cross section between the supply curve and the inelastic demand shifted around the zonal net position (import or export).

Combining these metrics with other results from an eMark simulation will provide a range of useful results metrics to evaluate the market-based dispatch and compare various scenarios. Other useful results include the hourly generator schedule (i.e. dispatch), the generator operating costs, the market prices, the curtailment of non-dispatchable generators, the import and export between market zones, and the transmission line flows.

3.2 Modeling of sequential markets

In this section we present a model that is able to describe a sequential electricity market structure. Figure 4 shows the considered market stages with their interactions. Each market zone has a forward, day-ahead and balancing market stage. The market zones interact with each other (i.e. imports or exports) through coupling mechanisms such as an ATC trade limit.

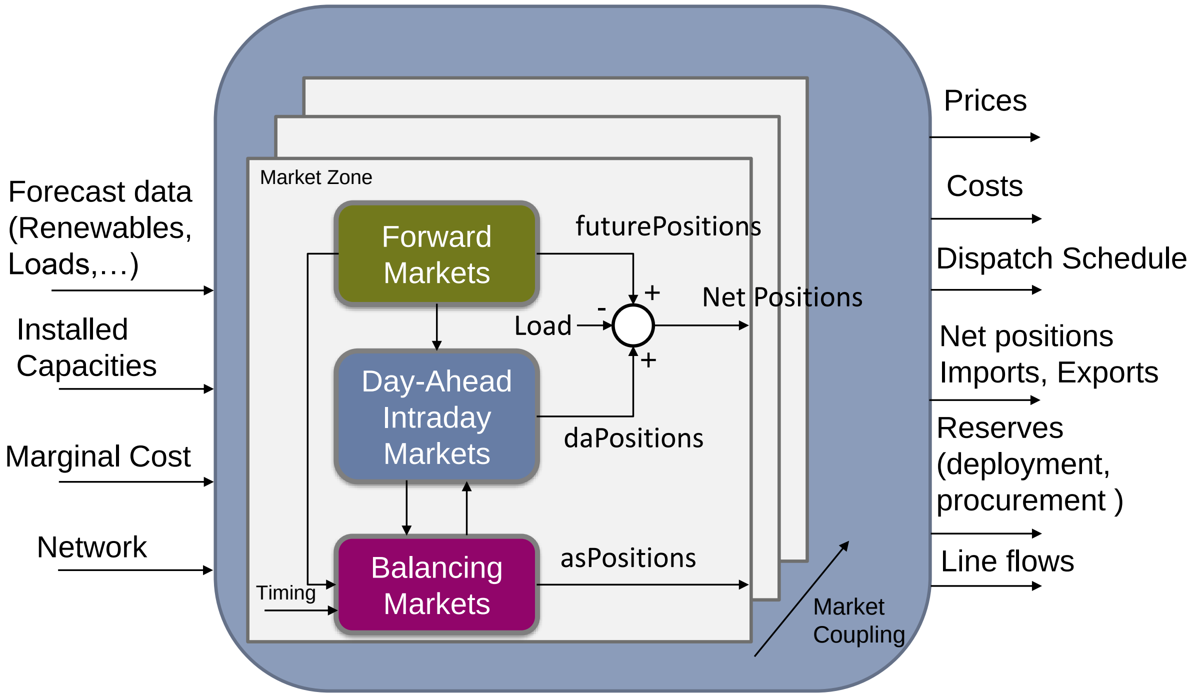


Figure 4: Interaction of the considered markets in Nexus-e.

3.2.1 Futures market

Since a significant share of electricity is traded over forward contracts, it is necessary to model this stage. In eMark, a FuM clearing is modeled to capture forward contracts, since it is a good approximation to price forward contracts. The FuM clearing is solved for each month with all FuM generator injections assumed to be constant over all hours of a given month. Prior to running the FuM clearing, a spot market simulation (equivalent to the hourly day-ahead clearing) is run for the full month to initialize some of the expected production levels. For this initialization, the full hourly zonal loads are used along with all available generator capacities. From the results of this spot market clearing, the average hourly production level of each generator $\overline{p}_{\mathrm{g}}^{\mathrm{sp}}$ and the average hourly load for each node $\overline{p}_{\mathrm{d}}^{\mathrm{sp}}$ are computed for each month. The average production levels are multiplied by the user-defined generator hedge ratios $\vec{h}_{\mathrm{g}}^{\mathrm{fu}}$ to compute the generator supply capability $\vec{c}^{\mathrm{fu}}$ for the FuM clearing (12). Similarly the average load quantities are multiplied by load hedge ratios $\vec{h}_{\mathrm{d}}^{\mathrm{fu}}$ to compute the FuM load positions $\vec{p}_{\mathrm{d}}^{\mathrm{fu}}$ (13). Tables 3, 4 and 5 list the values implemented for the generator and load hedge ratios for the various zones and years simulated.

$$\vec{c}^{\mathrm{fu}} = \overline{p}_{\mathrm{g}}^{\mathrm{sp}} \vec{h}_{\mathrm{g}}^{\mathrm{fu}} \tag{12}$$

$$\vec{p}_{\mathrm{d}}^{\mathrm{fu}} = \overline{p}_{\mathrm{d}}^{\mathrm{sp}} \vec{h}_{\mathrm{d}}^{\mathrm{fu}} \tag{13}$$

Using the computed FuM generator capabilities and load requirements from the spot market initialization, the FuM clearing problem will determine the optimal future generation setpoints $\vec{p}_{\mathrm{g}}^{\mathrm{fu}}$ that minimize the total generation costs. Only dispatchable generators are allowed to offer capacity in the FuM clearing (hydro-RoR, wind and PV generators do not offer any capacity in the FuM clearing). Additionally, all storage generators except hydro dams are not modeled as participants in the FuM clearing since their

Table 3: Swiss generator hedge ratios by generator type. These ratios are utilized in the determination of how much capacity generators offer in the FuM clearing. The Dam hedge ratios change over time to help account for the loss of capacity participating in the FuM because of the nuclear phaseout.

Year	Dam	Nucl	Biom	GasCC	GasSC	Oil
2020	0.3	0.7	0.6	0.6	0.6	0.6
2030	0.3	0.7	0.6	0.6	0.6	0.6
2040	0.6	0.7	0.6	0.6	0.6	0.6
2050	0.6	0.7	0.6	0.6	0.6	0.6

Table 4: Non-Swiss generator hedge ratios by generator type. These ratios are constant over all years simulated.

Years	Dam	Nucl	Biom	GasCC	GasSC	Oil	Lign	Coal
2020-2050	0.3	0.6	0.6	0.6	0.6	0.6	0.6	0.6

charging/discharging operating behavior is not conducive to providing continuous power injections over all hours of a month. The monthly structure of the FuM is modeled such that any generator injecting power is set to inject the same amount of power over all hours of the month cleared. This monthly behavior enables a single optimization to represent the clearing problem for all hours of the month. The FuM clearing problem is given by:

$$
\begin{aligned}
& J^*(\vec{c}^{\,\mathrm{fu}}, LTC_{\min}, LTC_{\max}, \vec{p}_{\mathsf{d}}^{\,\mathrm{fu}}) = \min_{\vec{y}^{\,\mathrm{fu}}, \vec{p}_{\mathsf{g}}^{\,\mathrm{fu}}, \vec{p}_{\mathsf{t}}} \vec{1}^{\mathrm{T}} \vec{y}^{\,\mathrm{fu}} \\
& \text{s.t.} \\
& \text{(a)} \quad -\vec{C}_{\mathsf{gz}} \vec{p}_{\mathsf{g}}^{\,\mathrm{fu}} + \vec{C}_{\mathsf{ft}}^{z} \vec{p}_{\mathsf{t}} = -\vec{C}_{\mathsf{bz}} \vec{p}_{\mathsf{d}}^{\,\mathrm{fu}} \\
& \text{(b)} \quad LTC_{\min} \leq \vec{p}_{\mathsf{t}} \leq LTC_{\max} \\
& \text{(c)} \quad \underbrace{\begin{bmatrix} \vec{a}_1 & & \vec{0} \\ & \ddots & \\ \vec{0} & & \vec{a}_{n_g} \end{bmatrix}}_{\vec{A}_g} \vec{p}_{\mathsf{g}}^{\,\mathrm{fu}} - \vec{y}^{\,\mathrm{fu}} \geq \underbrace{\begin{bmatrix} \vec{b}_1 \\ \vdots \\ \vec{b}_{n_g} \end{bmatrix}}_{\vec{b}_g} \\
& \text{(d)} \quad \vec{0} \leq \vec{p}_{\mathsf{g}}^{\,\mathrm{fu}} \leq \vec{c}^{\,\mathrm{fu}} \quad ,
\end{aligned}
\tag{14}
$$

where $LTC_{\min}$ and $LTC_{\max}$ represent the contractual long term transmission rights to be utilized for cross-border trading. These limitations are the equivalent of an ATC-based zonal coupling for the FuM clearing and all zones are coupled in this way during the FuM clearing. Values implemented for the LTC limits can be found in Table 6 for each modeled From-To zone border. The vectors $\vec{a}_i, \vec{b}_i \in \mathbb{R}^{n_{bi} \times 1}$ define the PWA marginal cost segments for n_{bi} bids. The equality constraint (14a) represents power balance, where cross-border trades can be included by the cross-border flows $\vec{p}_{\mathsf{t}}$ between the market zones. Constraint (14b) bounds the cross-border flows and (14c) includes the epigraph formulation for the PWA marginal cost functions. The inequality (14d) bounds the generator setpoints. Note that $\vec{a}_i$ is a

Table 5: Load hedge ratios by market zone. The Swiss load hedge ratio is reduced in the 2040-2050 case to help account for the loss of nuclear capacity participating in the FuM.

Years	CH	AT	DE	FR	IT
2020-2030	0.3	0.3	0.3	0.3	0.3
2040-2050	0.2	0.3	0.3	0.3	0.3

function of $\vec{c}^{\mathrm{fu}}$.

Table 6: LTC trade limitations between market zones in megawatt (MW). These FuM zonal trade limits were based on data from the ENTSO-E Transparency Platform for the explicit transmission allocation of month-ahead transfer capacities [12].

		FROM				
		CH	**AT**	**DE**	**FR**	**IT**
TO	**CH**	—	160	300	200	650
	AT	450	—	5000	—	70
	DE	1200	5000	—	1000	—
	FR	200	—	600	—	700
	IT	800	110	—	990	—

3.2.2 Balancing market

Until recently, Switzerland operated a pay-as-bid BaM but has now shifted the BaM to be based on a uniform auction. In eMark, the BaM is modeled as a uniform auction even though some of the historical years simulated during the validation phase still operated during the pay-as-bid auction mechanism. However, modeling these past years as a uniform auction is appropriate since the expected payments in a uniform price procurement auction will be the same as the expected payments in a pay-as-bid auction under the assumption that all bidders have perfect knowledge [13]. Currently, eMark only includes the BaM clearing for the Swiss zone since this is the focus of the analysis, but the same clearing problem can be solved separately to as many zones as desired assuming no zonal trading of reserve products. Additionally, eMark considers two balancing market products: the FCR and the FRR. FCR is modeled as a symmetric product (meaning the positive and negative requirements are equal) with specified hourly requirements that are constant over each weekly period. FRR is modeled similarly with constant weekly requirements but with a non-symmetric positive and negative requirement (i.e. the positive and negative requirement can be different in a given week). Each product is cleared over a one week period using available generator capacities that were not already allocated in the FuM clearing. Only generators that are allowed to participate in the FuM are allowed to participate in the BaM. While the positive and negative FRR requirement in any single hour can be provided by different generators, any generator providing FCR must provide an equal amount of positive and negative capacity (i.e. symmetric generator procurement). Additionally, the weekly structure of the Swiss BaM is reflected since any generator supplying any of the BaM products must reserve the associated capacity for all hours of the week (i.e. the same generators provide the reserve products over the full week). This weekly structure enables a single optimization to represent the clearing problem for all hours of the week. The generic clearing problem for the BaM products determines the optimal reserve power setpoints $\vec{p}_{\mathrm{g}}^{\mathrm{x}}$ in a market zone that minimize the total production costs and is given by:

$$
\begin{aligned}
J^{*}(\vec{c}_{\min}^{\mathrm{x}}, \vec{c}_{\max}^{\mathrm{x}}, r^{x}) = \quad & \min_{\vec{y}^{\mathrm{x}}, \vec{p}_{\mathrm{g}}^{\mathrm{x}}} \vec{1}^{\mathrm{T}} \vec{y}^{\mathrm{x}} \\
& \text{s.t.} \\
& \text{(a)} \quad \vec{1}^{\mathrm{T}} \vec{p}_{\mathrm{g}}^{\mathrm{x}} = r^{x} \\
& \text{(b)} \quad \vec{A}_{g} \vec{p}_{\mathrm{g}}^{\mathrm{x}} - \vec{y}^{\mathrm{x}} \geq \vec{b}_{g} \\
& \text{(c)} \quad \vec{c}_{\min}^{\mathrm{x}} \leq \vec{p}_{\mathrm{g}}^{\mathrm{x}} \leq \vec{c}_{\max}^{\mathrm{x}} \quad ,
\end{aligned}
\tag{15}
$$

where x represents the reserve product (either FCR or FRR), $\vec{c}_{\min}^{\mathrm{x}}, \vec{c}_{\max}^{\mathrm{x}}$ are the minimum and maximum generator reserve capability that can be offered and r^{x} is the zonal up or down reserve requirement. The equality constraint (15a) ensures the full reserve requirement is met. Constraint (15b) includes the formulation for the PWA marginal cost functions and the inequality (15c) bounds the generator reserve power setpoints.

3.2.3 Day-ahead market

The remaining zonal loads that are not supplied in the FuM will be supplied in the DaM clearing. All generator capacities that are not already allocated in the FuM clearing or BaM clearing along with all non-dispatchable generator injections (hydro-RoR, wind, and PV) are available in the DaM to supply the remaining hourly electricity demand. Additionally, all remaining zonal transfer capacity not used by the power flows of the FuM clearing are made available to allow additional zonal trading in the DaM. However, unlike the FuM, the market coupling that limits the trading of electricity between market zones in the DaM can be set as either ATC-based or FB. The corresponding clearing problem determines the optimal generation setpoints $\vec{p}_{\mathsf{g}}^{\mathrm{da}}$ that minimize the total generation costs. All non-dispatchable generators are included in the DaM clearing with assumed hourly injections based on pre-defined profiles. Curtailments of the non-dispatchable injections is allowed but would generally result in a reduced social welfare since a higher priced generator would most likely be used instead of the curtailed non-dispatchable injection. Pumped hydro and all other forms of storage are also included in the DaM clearing with their generation(consumption) modeled as positive(negative) priced offers. The DaM clearing is solved separately for each hour of the year. The DaM clearing problem is given by:

$$
\begin{aligned}
J^*(\vec{c}_{\min}^{\mathrm{da}}, \vec{c}_{\max}^{\mathrm{da}}, ATC_{\min}, ATC_{\max}, \vec{H}_{\mathsf{fb}}, GSK, \vec{p}_{\mathsf{d}}^{\mathrm{fu}}, \vec{p}_{\mathsf{g}}^{\mathrm{fu}}, \vec{p}_{\mathsf{d}}^{\mathrm{da}}) = & \min_{\vec{y}^{\mathrm{da}}, \vec{p}_{\mathsf{net,fb}}^{\mathrm{z}}, \vec{p}_{\mathsf{g}}^{\mathrm{da}}, \vec{p}_{\mathsf{t}}} \vec{1}^T \vec{y}^{\mathrm{da}} \\
\text{s.t.} \quad & \\
\text{(a)} \quad & -\vec{C}_{\mathsf{gz}}\vec{p}_{\mathsf{g}}^{\mathrm{da}} + \vec{p}_{\mathsf{net,fb}}^{\mathrm{z}} + \vec{C}_{\mathsf{ft}}^{z}\vec{p}_{\mathsf{t}} = -\vec{C}_{\mathsf{bz}}\vec{p}_{\mathsf{d}}^{\mathrm{da}} \\
\text{(b)} \quad & \vec{1}^T\vec{p}_{\mathsf{net,fb}}^{\mathrm{z}} = 0 \\
\text{(c)} \quad & \vec{H}_{\mathsf{fb}}\, GSK\, \vec{p}_{\mathsf{net,fb}}^{\mathrm{z}} \geq -0.9\vec{s}_{\max} - \vec{H}_{\mathsf{fb}}(\vec{C}_{\mathsf{g}}\vec{p}_{\mathsf{g}}^{\mathrm{fu}} - \vec{p}_{\mathsf{d}}^{\mathrm{fu}}) + (\vec{H}_{\mathsf{fb}} - \vec{H}_{\mathsf{fb}}\, GSK\vec{C}_{\mathsf{bz}})\vec{p}_{\mathsf{d}}^{\mathrm{da}} \\
\text{(d)} \quad & \vec{H}_{\mathsf{fb}}\, GSK\, \vec{p}_{\mathsf{net,fb}}^{\mathrm{z}} \leq 0.9\vec{s}_{\max} - \vec{H}_{\mathsf{fb}}(\vec{C}_{\mathsf{g}}\vec{p}_{\mathsf{g}}^{\mathrm{fu}} - \vec{p}_{\mathsf{d}}^{\mathrm{fu}}) + (\vec{H}_{\mathsf{fb}} - \vec{H}_{\mathsf{fb}}\, GSK\vec{C}_{\mathsf{bz}})\vec{p}_{\mathsf{d}}^{\mathrm{da}} \\
\text{(e)} \quad & \vec{A}_g\vec{p}_{\mathsf{g}}^{\mathrm{da}} - \vec{y}^{\mathrm{da}} \geq \vec{b}_g \\
\text{(f)} \quad & ATC_{\min} \leq \vec{p}_{\mathsf{t}} \leq ATC_{\max} \\
\text{(g)} \quad & \vec{c}_{\min}^{\mathrm{da}} \leq \vec{p}_{\mathsf{g}}^{\mathrm{da}} \leq \vec{c}_{\max}^{\mathrm{da}} \quad ,
\end{aligned}
\tag{16}
$$

where $\vec{p}_{\mathsf{net,fb}}^{\mathrm{z}}$ represents the zonal net positions in the FB domain, $ATC_{\min}$,$ATC_{\max}$ are the minimum and maximum available transfer capacities and $\vec{c}_{\min}^{\mathrm{da}}$, $\vec{c}_{\max}^{\mathrm{da}}$ are the minimum and maximum supply capabilities. The equality constraint (16a) represents the zonal power balance, where the FB domain with the ATC domain are coupled by including ATC-based cross-border flows with the term $\vec{C}_{\mathsf{ft}}^{z}\vec{p}_{\mathsf{t}}$ and constraint (16f) and FB cross-border flows with the term $\vec{p}_{\mathsf{net,fb}}^{z}$. The ATC limits imposed were derived from Swissgrid [14] and ENTSO-E [15] data for historical day-ahead NTC values. The ATC will be endogenously calculated by subtracting the FuM cross border flows from the NTC values. Table 7 lists the NTC values utilized in all historical simulations. Some of these NTCs will be increased between 2020-2050 based on already planned cross border transmission expansions [16] and on assumed longer-term enhancements. Table 8 lists all modeled NTC increases and the years these increases occur. Equation (16b) ensures that the power flows in the FB domain are equal and opposite across any two FB coupled market zones (i.e. FB domain flows going out of one zone are equal to the FB domain flows going into the coupled zone). Constraints (16c,d) incorporate the FB domain that project the zonal net position with the PTDF matrix $\vec{H}_{\mathsf{fb}}$ and the GSK matrix to the branch flows. Compared to Equation (11), (16c,d) must additionally account for the impact of the future market positions ($\vec{p}_{\mathsf{g}}^{\mathrm{fu}}$ and $\vec{p}_{\mathsf{d}}^{\mathrm{fu}}$) on the line flows as well as set a flow reliability margin (FRM) to 10% of the maximum line capacity $\vec{s}_{\max}$. Note that the PTDF matrix $\vec{H}_{\mathsf{fb}}$ represents the area of all interconnected FB market zones, in which all desired critical branches are specified. Constraint (16e) includes the formulation for the PWA marginal cost functions and the inequality (16g) bounds the generator setpoints.

Table 7: NTC trade limitations between market zones in MW as modeled for all historical simulations (i.e. prior to 2020). These DaM zonal trade limits were based on data from the Swissgrid [14] and ENTSO-E Transparency Platform for the forecasted transmission allocation of day-ahead transfer capacities [15]. Note that the large values for the DE-FR and DE-AT connections are because these borders are already FB coupled.

		FROM				
		CH	**AT**	**DE**	**FR**	**IT**
TO	**CH**	—	533	800	3000	1910
	AT	1200	—	9657	—	200
	DE	4000	9657	—	8074	—
	FR	1200	—	8074	—	2400
	IT	4240	1200	—	2400	—

Table 8: Changes to NTC trade limitations between market zones in MW as modeled for all 2020-2050 simulations. These NTC increases are based on already planned cross border transmission expansions [16] and assumed longer-term enhancements.

TO	FROM	MW	Years
DE	CH	4000	2040-2050
CH	FR	3000	2040-2050
DE	FR	9236	2030-2050
FR	DE	9236	2030-2050
DE	AT	13395	2020
DE	AT	14895	2030-2050
AT	DE	13395	2020
AT	DE	14895	2030-2050
FR	IT	3801	2020-2050
IT	FR	3801	2020-2050
IT	AT	295	2020
IT	AT	1218	2030-2050
AT	IT	295	2020
AT	IT	1218	2030-2050

3.3 Coupled market procedure

The market clearing algorithms were introduced in the previous Section. In this section we aim to show how these markets are coupled with each other and which information needs to be passed between the markets in a simulation framework. Figure 5 shows the sequence diagram of the three different processes: Future Market, Balancing Market, and Day-ahead Market (note that the Realization step is not currently utilized since reserve deployments are outside of the scope of the Nexus-e analysis). This graphic illustrates the time scales that the different clearing processes run at and which results flows from/to the involved processes. The following subsections detail the corresponding processes by using pseudo algorithms.

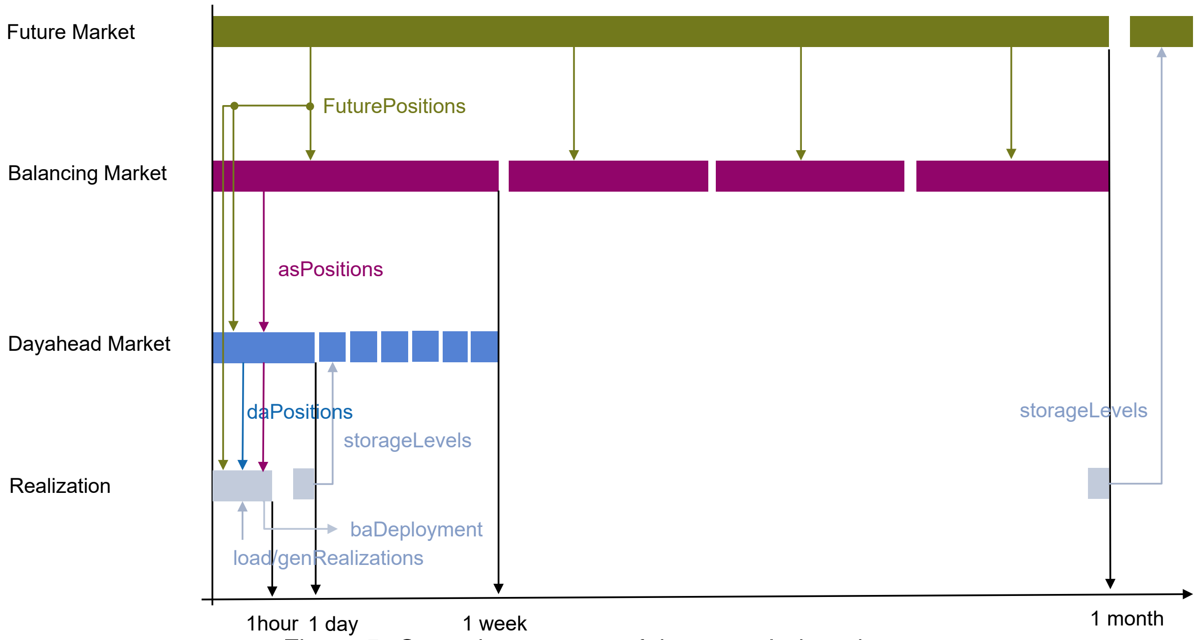


Figure 5: Operating strategy of time-coupled markets.

3.3.1 Future market strategy

The first process is the future market clearing stage, which is cleared on a monthly basis. To calculate production levels and prices, a spot market simulation is performed as presented in [6] for a given month. This spot market clearing is equivalent to running the DaM clearing as presented in Equation (16). For the offers/bids, optimal hedge ratios are calculated as presented in [17].

Algorithm 1 Future market procedure (solves once for the month).

procedure BIDINTOANDCLEARFUTUREMARKET($\vec{x}$,$date$)
  run BidIntoAndClearDaMarket($\vec{x}$,$date$)
    ▷ run spot market without FuM and BaM positions
  $\vec{c}^{\mathrm{fu}} = (month/hrs_j) \sum_j \vec{p}_{\mathsf{g}}^{\mathrm{da}}(j) \vec{h}_{\mathsf{g}}^{\mathrm{fu}}$
    ▷ calc average day-ahead generation and multiply with hedge ratio
  $\vec{p}_{\mathsf{d}}^{\mathrm{fu}} = (month/hrs_j) \sum_j \vec{p}_{\mathsf{d}}^{\mathrm{da}}(j) \vec{h}_{\mathsf{d}}^{\mathrm{fu}}$
    ▷ calc average day-ahead load and multiply with hedge ratio
  solve problem (14)
  return $\vec{p}_{\mathsf{g}}^{\mathrm{fu}}$
end procedure

3.3.2 Balancing market strategy

The second process is the balancing market stage, which is cleared on a weekly basis. It takes the future positions as inputs from the future market stage. The units that participate in the future market stage can also offer capacities in the balancing market stage.

Algorithm 2 Balancing market procedure (solves once for the week).

procedure BIDINTOANDCLEARBAMARKET($\vec{p}_{\mathsf{g}}^{\mathrm{fu}}, \vec{r}^{\mathrm{FCR}}, \vec{r}^{\mathrm{FRR+}}, \vec{r}^{\mathrm{FRR-}}$)
  for $jj = 1 : n_z$ **do**
    $c_{\max}^{\mathsf{FCR}} = \min(\vec{p}_{\mathsf{gen}}^{\max} - \vec{p}_{\mathsf{g}}^{\mathrm{fu}}, \vec{p}_{\mathsf{g}}^{\mathrm{fu}} - \vec{p}_{\mathsf{gen}}^{\min})$
      ▷ calc symmetric generator capability
    $\vec{p}_{\mathsf{g}}^{\mathrm{FCR}}(jj)$ = solve problem (15)
    $c_{\max}^{\mathsf{FRR+}}(jj) = \vec{p}_{\mathsf{gen}}^{\max} - \vec{p}_{\mathsf{g}}^{\mathrm{fu}} - \vec{p}_{\mathsf{g}}^{\mathrm{FCR}}$
      ▷ calc upward generator capability
    $\vec{p}_{\mathsf{g}}^{\mathrm{FRR+}}(jj)$ = solve problem (15)
    $c_{\max}^{\mathsf{FRR-}}(jj) = \vec{p}_{\mathsf{g}}^{\mathrm{fu}} - \vec{p}_{\mathsf{g}}^{\mathrm{FCR}} - \vec{p}_{\mathsf{gen}}^{\min}$
      ▷ calc downward generator capability
    $\vec{p}_{\mathsf{g}}^{\mathrm{FRR-}}(jj)$ = solve problem (15)
  end for
  return $\vec{p}_{\mathsf{g}}^{\mathrm{FRR+}}, \vec{p}_{\mathsf{g}}^{\mathrm{FRR-}}, \vec{p}_{\mathsf{g}}^{\mathrm{FCR}}$
end procedure

3.3.3 Day-ahead market strategy

The third process is the day-ahead market stage, which is cleared on a daily basis. It takes the inputs from the two aforementioned stages and determines the remaining generation capacities that can available to offer into this market. It runs each hour individually and determines a dispatch schedule for the next 24 hours. Since each hour is solved individually with no accounting for future behaviors, this formulation does not endogenously account for medium-term (daily) storage characteristics nor for long-term (seasonal) storage characteristics. Instead, in eMark heuristics are included for hydro dams to emulate the typical seasonal reservoir filling curve for Switzerland using either the historical or the CentIv provided monthly ending reservoir full ratios r_m (generally reservoirs are filled over the summer, reaching full around Sep/Oct, then emptied during winter and spring, reaching empty around April). Additionally, other heuristics are used for hydro pumps to reflect typical daily cycles where a certain number of on-peak and off-peak hours are identified for discharging and charging. These heuristic approaches represent the most significant limitation of the eMark module.

Algorithm 3 Day-ahead market procedure (solves each hour of one day).

procedure BIDINTOANDCLEARDAMARKET($\vec{x}$,$datetime$,r_m,$\vec{p}_{\text{g}}^{\text{fu}}$,$\vec{p}_{\text{t}}$,$\vec{p}_{\text{d}}^{\text{fu}}$, $\vec{p}_{\text{g}}^{\text{FRR+}}$, $\vec{p}_{\text{g}}^{\text{FRR-}}$, $\vec{p}_{\text{g}}^{\text{FCR}}$)

initialize $m =$ month that $datetime$ is in ▷ determine month of this hour

if $r_{m-1} < r_m$ **then** ▷ Hydro Dam bidding ▷ check if monthly start level is less than monthly end level

chargeEvent = 1 ▷ dam reservoir is charging

else

chargeEvent = 0 ▷ dam reservoir is discharging

end if

$duration$ = endMonthDate$_m$ - $datetime$ ▷ calc # hours between current hour and end of month

if chargeEvent = 1 **then**

$\vec{e}_{\text{ToFill,dam}} = r_m \vec{x}_{\max} - \vec{x}$ ▷ calc total energy to generate over the month

$\vec{p}_{\text{bid}}^{\text{dam}} = (\vec{e}_{\text{inflow}}(duration) - \vec{e}_{\text{ToFill,dam}})/duration$ ▷ set avg hydro dam offers

else

$\vec{e}_{\text{ToEmpty,dam}} = \vec{x} - r_m \vec{x}_{\max}$ ▷ calc total energy to generate over the month

$\vec{p}_{\text{bid}}^{\text{dam}} = (\vec{e}_{\text{inflow}}(duration) + \vec{e}_{\text{ToEmpty,dam}})/duration$ ▷ set avg hydro dam offers

end if

dam heuristic: $\vec{p}_{\text{d,peak,dam}}^{\text{da}} \subset \vec{p}_{\text{d}}^{\text{da}}$ ▷ set heuristic category for dam peak hours of the year

if any $\vec{p}_{\text{d}}^{\text{da}}(datetime)$ if this day $\in \vec{p}_{\text{d,peak,dam}}^{\text{da}}$ **then** ▷ check if any hours this day are in heuristic dam peak hours

$\vec{p}_{\text{bid}}^{\text{dam}} = \vec{p}_{\text{gen}}^{\max}$ ▷ reset hydro dam offers to max for such hours

end if

initialize $hr_{\text{turb}} = 4$ ▷ Hydro Pump bidding ▷ set basis for # of hrs per day pumps can discharge

initialize $hr_{\text{pump}} = 5$ ▷ set basis for # of hrs per day pumps can charge

set $\vec{x}_{\max}^{\text{pump}} = 0.95$ ▷ define maximum pump reservoir level of 95% full

set $\vec{x}_{\min}^{\text{pump}} = 0.05$ ▷ define minimum pump reservoir level of 5% full

pump heuristic: $\vec{p}_{\text{d,peak,pump}}^{\text{da}} \subset \vec{p}_{\text{d}}^{\text{da}}$ ▷ set heuristic category for pump peak hours of the year

if any $\vec{p}_{\text{d}}^{\text{da}}(datetime)$ of this day $\in \vec{p}_{\text{d,peak,pump}}^{\text{da}}$ **then** ▷ check if any hours this day are in heuristic pump peak hours

$hr_{\text{turb}} = hr_{\text{turb}} +$ # pump peak hrs this day ▷ increase # of discharging hours in this day

end if

if any $\vec{p}_{\text{d}}^{\text{da}}(datetime) < 0$ **then** ▷ check if any hours this day have negative zonal demand

$hr_{\text{pump}} = hr_{\text{pump}} +$ # negative demand hrs this day ▷ increase # of charging hours in this day

end if

$hr_{\text{onpeak}}^{\text{idx}} = hr_{\text{turb}}$ on-peak hours of this day ▷ identify desired number of on-peak hours for discharging in this day

$hr_{\text{offpeak}}^{\text{idx}} = hr_{\text{pump}}$ off-peak hours of this day ▷ identify desired number of off-peak hours for charging in this day

$\vec{e}_{\text{ToFill,pump}} = \vec{x}^{\text{pump}}_{\max} - \vec{x}$ ▷ calc available increase in pump storage volume to get to max daily level

$\vec{e}_{\text{ToEmpty,pump}} = \vec{x} - \vec{x}^{\text{pump}}_{\min}$ ▷ calc available decrease in pump storage volume to get to min daily level

$\vec{p}^{\text{pump}}_{\text{bid,charge}} = -(\vec{e}_{\text{ToFill,pump}})/hr_{\text{pump}}$ ▷ set max hydro pump offers for charging hours of the day

$\vec{p}^{\text{pump}}_{\text{bid,discharge}} = (\vec{e}_{\text{ToEmpty,pump}})/hr_{\text{turb}}$ ▷ set max hydro pump offers for discharging hours of the day

for jj = 1 To 24 **do** ▷ setup hourly optimization problem

  $\vec{p}^{\text{da}}_{\text{d}} = \vec{p}_{\text{d}}(jj) - \vec{p}^{\text{fu}}_{\text{d}}(jj)$ ▷ DaM load is remainder of total load not supplied by FuM

  $\vec{p}^{\text{conv}}_{\text{bid}} = \vec{p}^{\max}_{gen}$ ▷ conventionals offer based on their max capacity

  $\vec{p}^{\text{renewable}}_{\text{bid}} = \vec{p}^{\text{profiles}}_{gen}(jj)$ ▷ renewables offer based on their hourly profile (hydro-RoR, wind, PV)

  $\vec{p}^{\text{dam}}_{\text{bid}} = \vec{p}^{\text{dam}}_{\text{bid}}(jj)$ ▷ hydro dams offer is based on the dam heuristic

  if $jj \in hr^{\text{idx}}_{\text{onpeak}}$ **then** ▷ check if this hour is one of the on-peak pump discharging hours

    $\vec{p}^{\text{pump}}_{\text{bid}} = \vec{p}^{\text{pump}}_{\text{bid,discharge}}$ ▷ hydro pumps offer to discharge based on the pump heuristic

  else if $jj \in hr^{\text{idx}}_{\text{offpeak}}$ **then** ▷ check if this hour is one of the off-peak pump charging hours

    $\vec{p}^{\text{pump}}_{\text{bid}} = \vec{p}^{\text{pump}}_{\text{bid,charge}}$ ▷ hydro pumps offer to charge based on the pump heuristic

  else

    $\vec{p}^{\text{pump}}_{\text{bid}} = 0$ ▷ hydro pumps are idle based on the pump heuristic

  end if

  $\vec{c}^{\text{da}}_{\max}(jj) = \vec{p}_{\text{bid}} - \vec{p}^{\text{fu}}_{\text{g}} - \vec{p}^{\text{FRR+}}_{\text{g}} - \vec{p}^{\text{FCR}}_{\text{g}}$ ▷ calc generator capability accounting for FuM and BaM capacity allocations

  $ATC_{\min}, ATC_{\max}$ = updateATCMargins($\vec{p}_{\text{t}}$) ▷ update the ATC limits accounting for FuM flows

  solve problem (16) ▷ solve hourly optimization problem

end for

return $\vec{p}^{\text{da}}_{\text{g}}$

end procedure

4 Representation of flexibility

The demand for flexibility in the power system is materialized in several ways; two of the most important are: 1) the requirement to procure reserves (i.e. generator capacity that is withheld and prepared to increase or decrease power injections to cover short term supply-demand mismatches) and 2) the need for dispatchable generators along with imports and exports to supply the system net load (i.e. the load minus supply that comes from non-dispatchable generators like wind and PV).

In eMark, the demand for flexibility is captured in two ways. First, the demand for flexibility is accounted for by including any increase in the system reserve requirements needed to cover the additional forecast uncertainty that is introduced by newly built wind or PV capacity. This increased reserve level is determined within CentIv and passed in the interface to eMark. Second, the demand for flexibility is also captured in the dynamic nature of the system net load. As more non-dispatchable units are built in Switzerland, in particular PV units, the net load becomes more dynamic with significantly steeper slopes that the dispatchable generators and imports/exports must match.

Additionally, in eMark the supply of flexibility is captured in three ways. First, eMark accounts for the supply of flexibility that is provided by load shifting demand-side management (DSM) or battery storage system (BSS) in DistIv. Typically these distributed units shift demand within one day from hours of high demand to hours of low demand, effectively flattening the demand curve. A less rapidly changing demand profile means that eMark will have less trouble utilizing the dispatchable centralized units and imports/exports to balance supply with demand. Second, eMark models the operational capabilities of generators and storages in the centralized level such as hydro dams and pumps that are principal sources of flexibility and can rapidly respond to changes in demand. These types of generators should become even more important if large amounts of PV are built and yield a much more rapidly changing net load profile for Switzerland. Third, eMark applies realistic cross border trade flow limits (NTCs) which facilitate the second main source of flexibility supply via imports and exports from other interconnected market zones. Using the NTC limits instead of the full transmission line limits at these borders is key because it allows a realistic representation of how much electricity is actually allowed to flow into and out of Switzerland.

Overall, these aspects allow eMark to represent the demand for flexibility in the form of reserve requirements and the dynamic net load profile along with the supply of flexibility in the form of distributed and centralized generators along with imports and exports.

5 Description of interfaces

The most significant novelty of the Nexus-e platform is that it combines the core modules used in a sophisticated way with automated interfaces to pass all necessary information between modules as shown in Figure 6. The eMark module is connected within the Energy-Economic loop of this framework with an input interface where data is coming from the CentIv, DistIv, and GemEl modules and an output interface that sends data to the GemEl module. Additionally, eMark is connected within the Security loop of the framework with an output interface to Cascades and and input interface receiving data back from Cascades. The following subsections provide an overview of these interfaces.

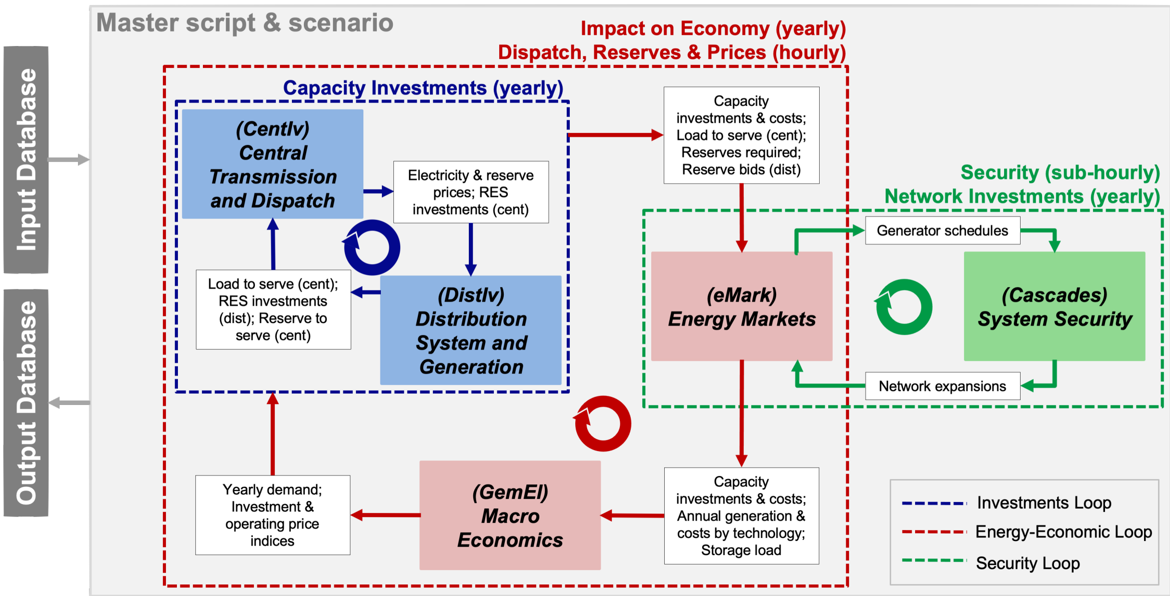


Figure 6: Illustration of the integration and interfacing of the various modules used in Nexus-e.

5.1 Investments-eMark interface

CentIv and DistIv are combined in the Investment loop to determine new capacity investments in Switzerland. Once these modules have completed the optimization of investment decisions, they provide information about these investments along with other parameters over an interface to eMark. Hence, this interface combines the results from two modules. Based on these data, eMark optimizes the generator schedules over the full year to supply the energy and reserve demands. Table 9 shows details of the data transferred for this interface.

Table 9: Investments-eMark module interface details.

Variable	Resolution	Unit	Description
Generator ID's	by unit	–	Generator database identifiers
Generator capacities	by unit	MW	Generator capacities
Generator variable costs	by unit	CHF/MWh	Total variable operation and maintenance (OM) costs
System reserve requirements	hourly, zonal	MW	Requirement for each reserve product
Dam monthly storage levels	monthly	MWh	Aggregate Swiss energy volume in Dam reservoirs at the end of each month
Original demand	hourly, nodal	MWh	Original electricity load to serve
Residual demand	hourly, nodal	MWh	Residual load after distribution self-supply (DistIv)
Curtailments	hourly, nodal	MWh	Curtailments by CentIv of DistIv injections
Demand shed	hourly, nodal	MWh	Load shed by CentIv
Demand scale ratio	annual	fraction	Swiss load scale ratio from GemEl

The generator ID's, capacities and variable costs are used to update eMark and include any newly built units by CentIv and any adjustment to generator operating costs from the GemEl cost indices. Note that investments in DistIv are not modeled in eMark but their injections are accounted for in the residual load. CentIv also provides any update to the reserve requirements that could increase as new renewable energy source (RES) capacities are built in either CentIv or DistIv. The monthly-ending dam storage levels are also updated by CentIv so that eMark will use the same seasonal pattern as CentIv. Note that CentIv optimizes the operation of Dams so the resulting seasonal pattern is not fixed to match the historical trend and can actually adjust to any future scenario. The nodal demand (i.e. original and residual), curtailments, and demand shed are provided by CentIv and DistIv so that eMark sets the proper hourly electricity demands (i.e. accounting for electricity supplied by DistIv, curtailments of DistIv injections required by CentIv, and any additional demand shed needed by CentIv). Two variables passed to eMark over this interface actual originate from the GemEl module but are first used within the Investments loop: 1) the load scale ratio represents the reaction of demand to changes in the economy or energy sector, and 2) the generator variable costs were adjusted by GemEl as a second from of response to the expenses incurred in the electricity sector.

5.2 eMark-GemEl interface

The interface from eMark to GemEl passes information on the annual operating costs and generation share by technology type for new and existing generators. This information is mapped to the technologies used in the GemEl module and used to recalibrate GemEl to reflect the new generation mix and costs. Table 10 shows details of the data transferred for this interface.

Table 10: eMark-GemEl module interface details.

Variable	Resolution	Unit	Description
Variable OM cost	annual, by unit type	mill CHF	Variable OM costs per technology type
Generation share	annual, by unit type	megawatt hour (MWh)	Generation per technology type

5.3 eMark-Cascades interface

The interface from eMark to the Cascades module benefits Cascades because of the realistic market-based generation dispatch coming from eMark, a feature that Cascades internally does not have. The eMark-Cascades interface data consists of system physical (i.e. grid) and operational (i.e. dispatch) data, which are listed in Table 11.

Table 11: eMark-Cascades module interface details.

Variable	Resolution	Unit	Description
mpc version	–	–	Version for MatPower mpc structure, e.g., '2'
mpc base mega-volt ampere (MVA)	–	MVA	Base MVA assumed for MatPower mpc, e.g., 100
mpc bus data	by bus	various	Bus data in MatPower format
mpc branch data	by branch	various	Line data in MatPower format
mpc gen data	by unit	various	Generator data in MatPower format
mpc gen cost data	by unit	various	Generator cost data in MatPower format
mpc gen info	by unit	various	Additional generator information
Load realization	hourly, nodal	MW	Nodal power demand in each hour
Generation positions	hourly, by unit	MW	Generator power injections in each hour
FCR procurements	hourly, by unit	MW	Generator power injections in each hour
Positive FRR procurements	hourly, by unit	MW	Generator power injections in each hour
Negative FRR procurements	hourly, by unit	MW	Generator power injections in each hour
Flow type	–	–	The power flow type (alternating current (AC), direct current (DC))
Swiss zone number	–	–	The Swiss zone number

Through this interface, eMark passes the power system physical data including the final list of power generation capacities to the Cascades module along with the final hourly power demand. Additionally, eMark provides Cascades the power output of each unit (generation dispatch), the power exchange between Switzerland and the neighboring countries (imports and exports), and the procured power reserves (FCR, positive and negative FRR) that each generating unit in the power system provides. The time resolution of the provided data is one hour and the time horizon is one year.

5.4 Cascades-eMark interface

The interface from Cascades to eMark benefits eMark because it can perform the market dispatch including the potential transmission system upgrades given by Cascades. The Cascades-eMark interface data consists of the physical characteristics of the proposed branch upgrades, as listed in Table 12.

Table 12: Cascades-eMark module interface details.

Variable	Resolution	Unit	Description
mpc branch data (new)	by branch	various	branches to be upgraded in MatPower format

Through the Cascades-eMark interface, Cascades provides eMark with the lines/transforms that are proposed for upgrade (expansion plan). The list of branches to be built/upgraded is updated at each iteration between Cascades and eMark, and the full list is transferred to eMark. In other words eMark is receiving a list of branches that consists of the branches from the current iteration and all previous iterations. The exchange of information between the modules continues until Cascades shows no need for further upgrades in the transmission system, i.e. after the reference security is reached.

6 Demonstration of results

A wide range of results are available from the eMark module related to the market clearing and to the design of the electricity market. These results provide a range of useful insights for evaluating the market-based dispatch and compare various scenarios. The demonstration results in this section provide a highlight of the capabilities and insights eMark provides. These results are only for illustrative purposes and are not meant to represent the final results of the Nexus-e simulation framework for any particular scenario. Results shown in Figures 7-11 are all taken from the same eMark simulation of 2015, including the Swiss generators and transmission network as they were at that time.

The primary purpose of eMark is to provide a market-based dispatch of the generator schedules. Therefore, one of the key set of results are the generator electricity injections. Figures 7 and 8 illustrate the monthly and hourly production from Swiss generators over a one year and one week period, respectively. Figure 7 highlights the longer-term trends over the year, in particular the seasonal pattern of production and imports/exports. The use of hydro and nuclear power dominate the Swiss generation mix and the massive natural water inflows during the summer make this season a time of higher net exports.

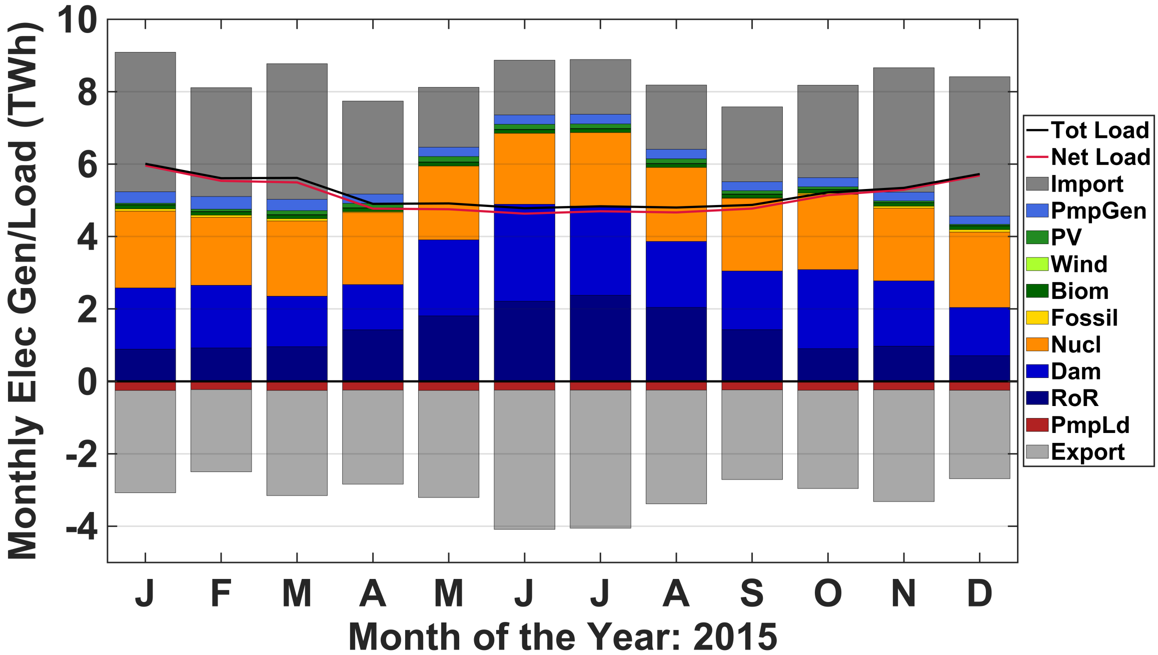


Figure 7: Monthly electricity supply/demand for Switzerland: production by technology type, imports, exports, total load, net load, and pump load.

Figure 8 highlights the short-term behaviors of different generator types, including hydro pumps and PV. It is evident from the hourly plot that during this week Switzerland is importing and exporting from different borders at the same time, but overall is a net importer (as expected in the late winter when other European countries are past their winter peak demand and Switzerland's reservoirs are near their lowest point). This image also demonstrates how the hydro pumps discharge (PmpGen) during hours of high Swiss demand and charge (PmpLd) during the lowest demand hours. These types of results provide valuable context to explore the use of the Swiss generation fleet on both short- and long-term scales.

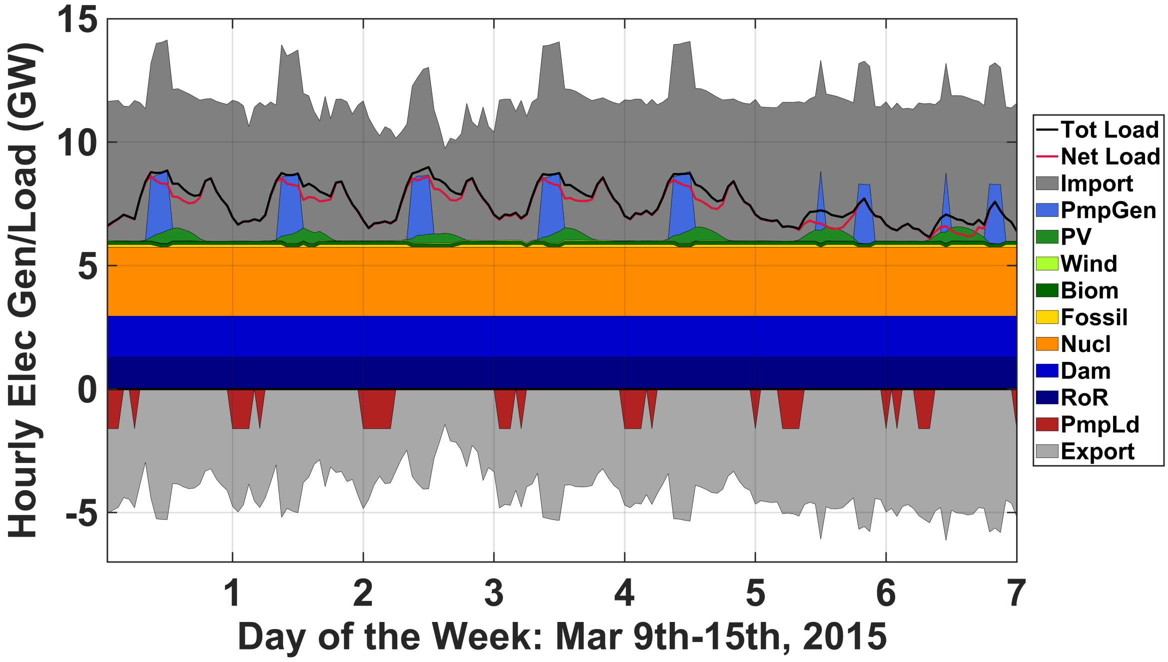


Figure 8: Hourly electricity supply/demand for Switzerland over a one week period (March 9th-15th): production by technology type, imports, exports, total load, net load, and pump load.

Another critical aspect of eMark is that it applies cross border contract trade limits for each border based on their current design (i.e. either NTC or FB) during the market clearing. This enables a much more realistic representation of the possible imports and exports across each border[2]. These realistic trade limits allow eMark to provide novel and meaningful results for the imports and exports of electricity across the Swiss borders. Figure 9 illustrates the simulated annual imports, exports, and net imports across each Swiss border in 2015. The simulation highlights that Switzerland is a primary importer from Germany and Austria, a primary exporter to Italy and closer balanced with France.

Additionally, by applying the NTC limits, eMark can provide results on how heavily utilized these NTCs tend to be. Figure 10 demonstrates that all the Swiss borders tend to heavily utilize the available transfer capacities, regardless of the flow direction. The NTC between Switzerland and France has the highest average utilization of 85% while the lowest utilization with Germany was still over 50%. These results emphasize the importance of using the NTC limit since it is much more conservative than assuming a limit based on the full cross border line ratings.

[2]Most models only limit cross border flows based on the physical line limits, which vastly overestimate the allowable imports and exports.

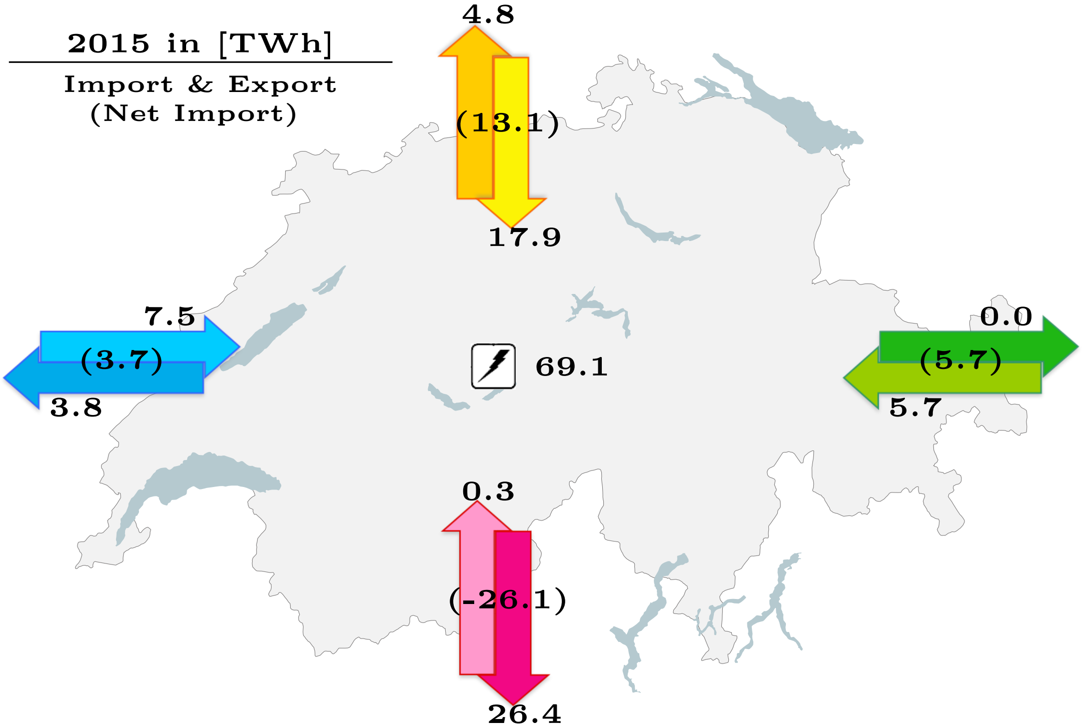


Figure 9: Annual Swiss imports and exports to each neighbor (net imports are in parenthesis).

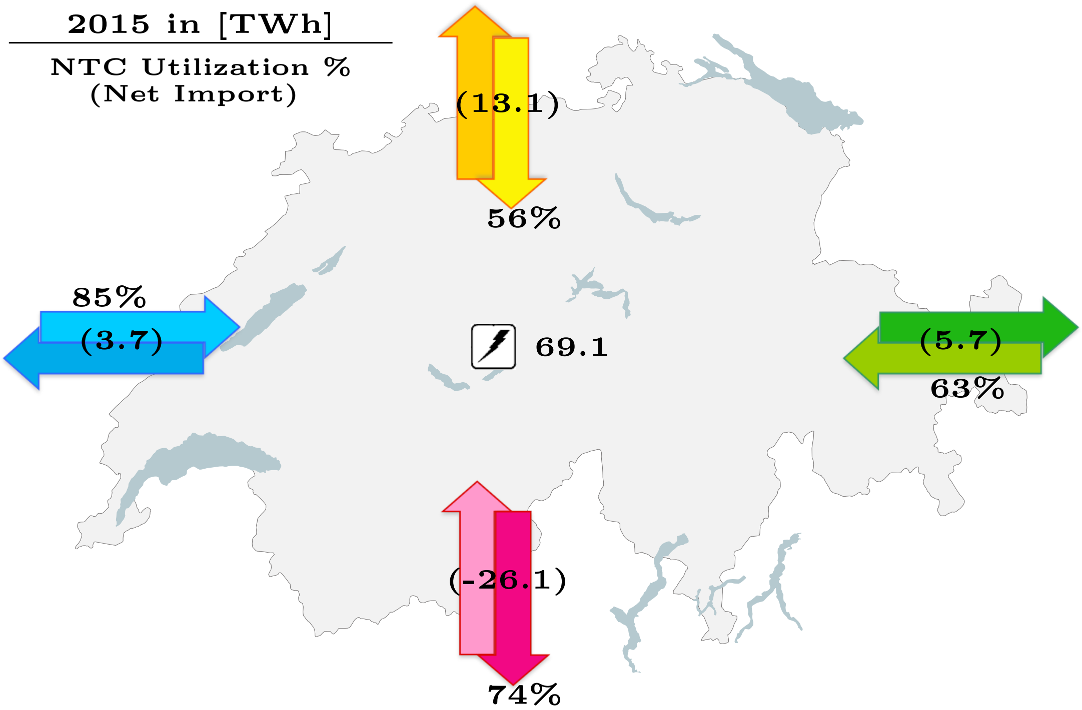


Figure 10: Annual average NTC ulitization to each neighbor (net imports are in parenthesis).

Another important aspect of the Swiss power system is the dominance of hydro generators, and in particular hydro dam units. Since these generators make up such a large percentage of the Swiss generation mix and because they tend to follow a longer-term (seasonal) pattern that aims to maximize profits from their large storage reservoirs, it is essential that eMark is able to reflect their seasonal behavior. Therefore, another important result to highlight is this seasonal pattern. Figure 11 shows how full the Swiss hydro storage levels are over the year for both hydro dams as well as for all hydro storage (i.e. dams and pumps) along with the known historical trend in 2015. The simulated dams follow exactly the desired seasonal trend while the storage level of the pumps tend to instead follow a daily cycle[3].

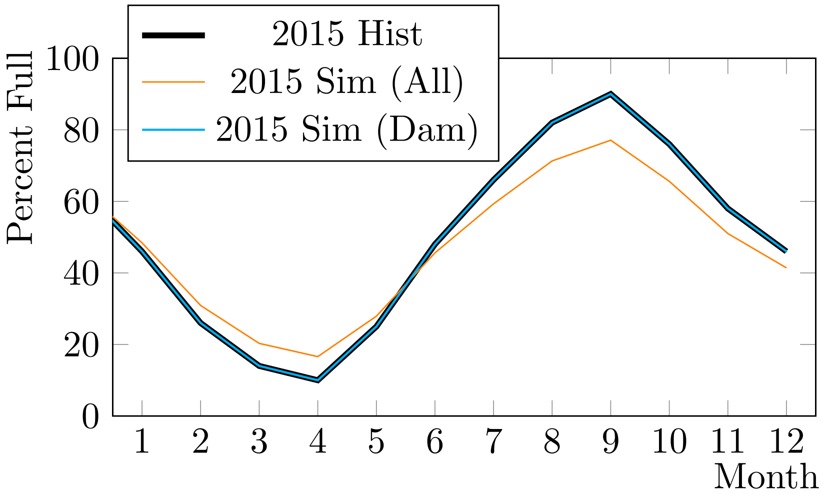


Figure 11: Swiss hydro storage level profile over the year (% full).

Other useful results that eMark can provide relate to comparing different scenarios. For example, Figure 12 demonstrates the potential benefits that can be gained by transitioning central Europe from ATC coupled markets to FB coupled markets. By making such a transition, the increased availability of transmission capacities would lead to increased imports and exports between market zones in an effort to enhance the use of lower costs generator capacities. Similarly, Figure 13 demonstrates the impact of the same transition on the Swiss consumer costs and producer surplus. In this case, the increased exports between Switzerland and Italy in the FB case lead to higher average clearing prices in Switzerland. The higher price in turn yields increased profits for the Swiss generators along with increased prices for the consumers.[4]

The results presented in this section give examples of some important metrics that eMark can provide. However, other valuable results that can be gained from eMark but are not presented above include: market clearing prices, reserve procurements, FuM versus DaM clearings, contracted trade volumes (the images above show the actual power flows), needed curtailments of non-dispatchable injections, among others.

[3]It is likely that the pumps would be charging during the last hour of the month, so their percentage full during this last hour could vary significantly from month to month. For this reason, it is not expected that their storage profile will follow the same long-term trend as dams.

[4]The simulation results shown in both Figures 12 and **??** were very preliminary and are only meant as an illustration and not to be used to make conclusions.

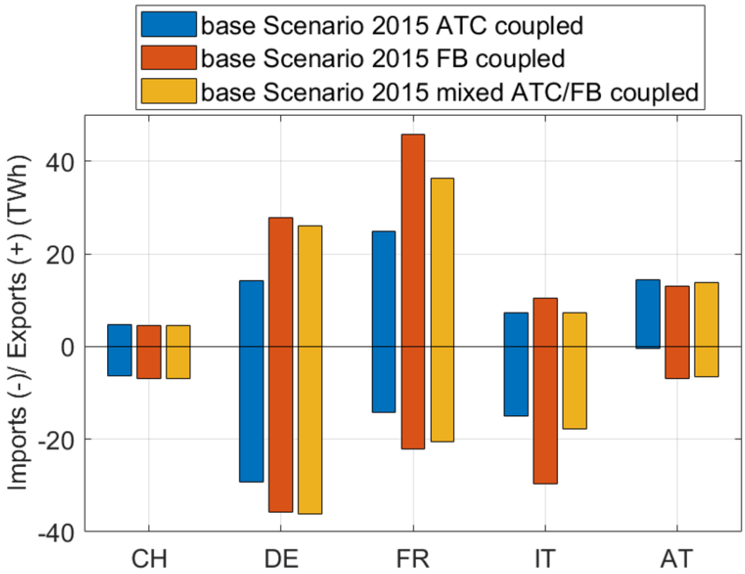


Figure 12: Transitioning from an ATC coupled market structure to a mixed or FB coupled structure can improve the utilization of transmission capacities.

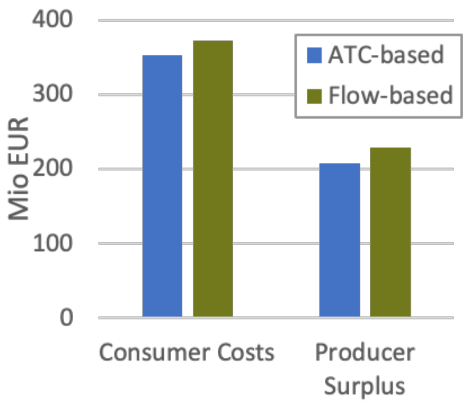


Figure 13: Annual Swiss consumer costs and producer surplus assuming an ATC or FB coupled market.

7 Publications

The following list describes publications related to the Nexus-e platform and the eMark module:

- A paper presented at the 2018 Power Systems Computation Conference details a new method to determine the susceptances of a reduced transmission network representation by using nonlinear optimization [11]. This method was developed to enable modeling of the flow-based market coupling mechanism currently used in the CWE region of Europe.
- A poster presented at the 2018 Conference by the Energy Modeling Platform for Europe (EMP-E) provided an overview of the Nexus-s integrated energy systems modeling platform [18].
- An article published in 2018 in the Energy Strategy Reviews journal [19] provides a thorough review of existing works related to modeling dimensions of the energy transition along with methods employed to combine various model types. The article then presents a proposal for an integrated linking of top-down and bottom-up models to represent: distributed generation and demand, operations of electricity grids, infrastructure investments and generation dispatch, and macroeconomic interactions.

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