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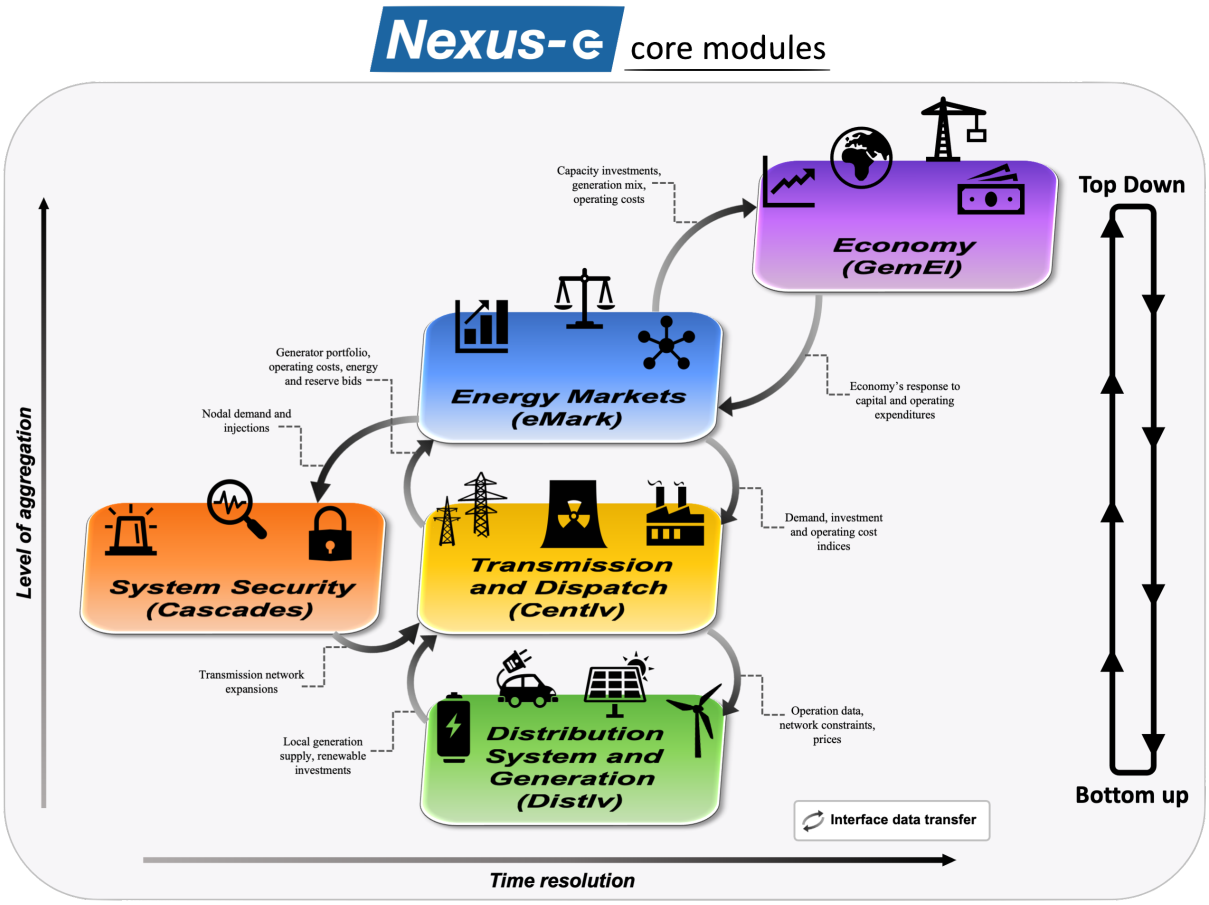
Final report

Nexus-e: Integrated Energy Systems Modeling Platform

Scenario Results Report



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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 report 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. This report illustrates the capabilities of the Nexus-e platform.

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 presents the results on how centralized and distributed technologies can address the increasing need for flexibility in the Swiss electricity system and how this affects the traditional operation of existing power generation units. We use the Nexus-e platform to simulate three scenarios: The *Baseline* scenario includes the projected development of techno-economic parameters (e.g., runtime of 50 years for Swiss nuclear power plants) and the status quo of the Swiss legislative and regulatory framework (e.g., financial subsidies for PV systems). The *Nuclear-60* scenario reflects the discussion on the nuclear power exit and assumes that nuclear power plants are phased-out after a lifetime of 60 years. The *High-Flexibility* scenario reflects the discussion on the impact and value of an increased supply of distributed flexibility in the power system and assumes low battery costs and high demand-side management potential.It is important to note that net-zero emissions targets (for Switzerland or the surrounding countries currently modeled) are not included in any of the simulated scenarios.

Our results show that the nuclear phase-out is achieved alongside substantial investments in new photovoltaic (PV) capacities without causing serious problems matching the supply of electricity with demand. This transition occurs along with some additional investments in biomass and PV-batteries, but no investment in wind power or grid-batteries. The ending of investment subsidies after 2030 reduces

the attractiveness of new PV capacities in 2040, but decreasing PV prices spur PV installations in 2050. By 2050, PV is responsible for the largest share (i.e., 32.6-35.5%) of electricity consumption, followed by hydro dam (26.0-28.3%) and hydro run of river (RoR) (15.9-17.4%). Additionally, as nuclear gets phased out, imports become a larger contributor to the supply of electricity in Switzerland providing up to 5.7% of the demand in 2050. Critical, however, is the time between 2030-2040, when the stagnating PV capacity cannot substitute nuclear phase-out fully, resulting in substantially higher net imports of up to 16.5% of the annual demand. Please note that all results presented in this report are subject to pronounced uncertainties and assumptions. Furthermore, the scenarios are illustrative and the results should be interpreted as indicating differences in the trends between scenarios and not interpreted as predictions. Therefore, we do not claim that the current legislative and regulatory framework is sufficient to achieve the renewable energy source (RES) targets.

In light of the transition away from nuclear capacities and toward PV capacities, there is an increasing need for flexibility across a wide range of timescales from seasonal to sub-hourly. By utilizing a comprehensive representation of the energy system, the Nexus-e platform assesses how these flexibility needs are supplied, namely through a combination of: capacities in the centralized Swiss generation fleet, imports and exports, and added capacities in the distribution system. First, the seasonality of the net load increases as the PV penetration level grows, indicating the need for higher seasonal flexibility, which is addressed by a greater seasonal reliance on net imports and hydro dams. Second, the increasingly dynamic pattern of the net load on an hourly and daily basis, which emphasizes the need for fast ramping flexible capacities, is mostly covered by rapid changes from imports and exports and hydro dams. To a lesser extent, hydro pumps, hydro RoRs, PV-batteries, and demand-side management (DSM) also react rapidly to help provide the necessary supply. Additionally, higher shares of flexible PV-batteries and DSM resources successfully smooth the hourly net load and thus reduce the reliance on imports/exports for hourly flexibility. Third, tertiary reserve requirements, needed to balance the sub-hourly deviations, increase from year-to-year as new PV investments are added and are supplied by the existing Swiss dispatchable capacities. Fourth, increasing the share of non-dispatchable units has a negative effect on the system security and thus contributes to the risk of systemic failures, but this risk can be addressed with only a couple of transmission line upgrades. PV-batteries and DSM can even further reduce such risk and strengthen system security.

The Nexus-e platform is a unique and powerful tool to quantify a wide range of impacts for possible future paths of the Swiss energy system. First of all, it combines bottom-up and top-down energy modeling approaches and thus represents a broader scope of the energy-economic system. This combination accounts for the complexity and interplay of energy demand-supply, macro energy-economic factors, and energy policy drivers across multiple time-scales and levels of aggregation. In terms of the modeled network levels, Nexus-e represents both the centralized and distributed levels of the energy system, which enables us to holistically assess the supply of flexibility across Switzerland at both regional and national scales. Also, Nexus-e is able to conduct simulations with a high-time resolution. The capability of modeling hourly dynamics allows us to capture new behaviors of hydro pumps, battery storage system (BSS), and DSM, which is critical for modeling the short-term demand and supply of flexibility. With such a comprehensive representation, we are able to show that Switzerland could achieve both the nuclear phase-out and RES targets while supplying sufficient flexibility and maintaining system security.

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.Dieser Report veranschaulicht die Fähigkeiten der Nexus-e Plattform.

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 präsentiert die Ergebnisse, wie zentrale und dezentrale Technologien dem zunehmenden Flexibilitätsbedarf im schweizerischen Elektrizitätssystem gerecht werden können und wie sich dies auf den traditionellen Betrieb der bestehenden Stromerzeugungsanlagen auswirkt. Wir verwenden die Nexus-e Plattform, um drei Szenarien zu simulieren: Das Baseline-Szenario beinhaltet die prognostizierte Entwicklung der technisch-ökonomischen Parameter (z.B. Laufzeit von 50 Jahren für Schweizer Kernkraftwerke) und den Status quo des schweizerischen Rechts- und Regulierungsrahmens (z.B. Subventionen für PV-Systeme). Das Nuclear-60-Szenario spiegelt die Diskussion um den Ausstieg aus der Kernenergie wider und geht davon aus, dass die Kernkraftwerke nach einer Laufzeit von 60 Jahren aus dem Betrieb genommen werden. Das Hoch-Flexibilitäts-Szenario spiegelt die Diskussion

über die Auswirkungen und den Wert eines erhöhten Angebots an verteilter Flexibilität im Stromsystem wider und geht von niedrigen Batteriekosten und einem hohen Potenzial für die Nachfragesteuerung aus.Es ist wichtig zu beachten, dass Netto-Null-Emissionsziele (für die Schweiz oder die umliegenden Länder, die derzeit modelliert werden) in keinem der simulierten Szenarien enthalten sind.

Unsere Ergebnisse zeigen, dass der Ausstieg aus der Kernenergie zusammen mit erheblichen Investitionen in neue PV-Kapazitäten erreicht wird, ohne ernsthafte Probleme zu verursachen, das Stromangebot mit der Nachfrage in Einklang zu bringen. Dieser Übergang erfolgt zusammen mit gewissen zusätzlichen Investitionen in Biomasse und PV-Batterien, aber ohne Investitionen in Windkraft oder Netzbatterien. Die Beendigung der Investitionszuschüsse nach 2030 verringert die Attraktivität neuer PV-Kapazitäten im Jahr 2040, aber sinkende PV-Preise kurbeln die PV-Installationen im Jahr 2050 an. Bis 2050 ist PV für den größten Anteil (d.h. 32,6-35,5%) des Stromverbrauchs verantwortlich, gefolgt von Speicher- (26,0-28,3%) und Flusswasserkraftwerken (15,9-17,4%). Hinzu kommt, dass mit dem Ausstieg aus der Kernenergie die Importe einen grösseren Beitrag zur Stromversorgung in der Schweiz leisten und im Jahr 2050 bis zu 5,7% der Nachfrage decken werden. Kritisch ist jedoch die Zeit zwischen 2030-2040, wenn die stagnierende PV-Kapazität den Ausstieg aus der Kernenergie nicht vollständig ersetzen kann, was zu wesentlich höheren Nettoimporten von bis zu 16,5% der jährlichen Nachfrage führt. Es ist zu beachten, dass alle in diesem Bericht vorgestellten Ergebnisse mit erheblichen Unsicherheiten und Annahmen behaftet sind. Darüber hinaus haben die Szenarien illustrativen Charakter, und die Ergebnisse sollten so interpretiert werden, dass sie auf Unterschiede in den Trends zwischen den Szenarien hinweisen und nicht als Vorhersagen interpretiert werden. Daher wird kann auch nicht vorausgesagt werden, ob der gegenwärtige gesetzliche und regulatorische Rahmen ausreicht, die Ziele für erneuerbare Energiequellen (EE) zu erreichen.

Angesichts des Übergangs weg von Kernkraftkapazitäten und hin zu PV-Kapazitäten besteht ein zunehmender Bedarf an Flexibilität über eine breite Palette von Zeitskalen von saisonal bis unterstündlich. Anhand einer umfassenden Darstellung des Energiesystems beurteilt die Plattform Nexus-e, wie dieser Flexibilitätsbedarf gedeckt wird. Dies geschieht durch eine Kombination aus Kapazitäten im zentralisierten schweizerischen Kraftwerkspark, Importen und Exporten sowie zusätzlichen Kapazitäten im Verteilsystem. Erstens nimmt die Saisonalität der Nettolast mit zunehmendem PV-Durchdringungsgrad zu, was auf den Bedarf an höherer saisonaler Flexibilität hinweist, der durch eine stärkere saisonale Abhängigkeit von Nettoimporten und Staudämmen gedeckt wird. Zweitens wird das zunehmend dynamische Muster der Nettolast auf stündlicher und täglicher Basis, das die Notwendigkeit schnell ansteigender flexibler Kapazitäten unterstreicht, größtenteils durch rasche Veränderungen bei den Importen und Exporten und den Staudämmen abgedeckt. In geringerem Maße reagieren auch Pumpen von Wasserkraftwerken, Flusswasserkraftwerke, PV-Batterien und DSM, um die notwendige Versorgung zu gewährleisten. Darüber hinaus glätten höhere Anteile an flexiblen PV-Batterien und DSM-Ressourcen erfolgreich die stündliche Nettolast und verringern so die Abhängigkeit von Importen/Exporten für die stündliche Flexibilität. Drittens steigen die tertiären Reserveanforderungen, die benötigt werden, um die unterstündlichen Abweichungen auszugleichen von Jahr zu Jahr, wenn neue PV-Investitionen hinzukommen und von den bestehenden steuerbaren Schweizer Kapazitäten versorgt werden. Viertens wirkt sich die Erhöhung des Anteils der nicht steuerbaren Einheiten negativ auf die Systemsicherheit aus und trägt somit zum Risiko von Systemausfällen bei. Dieser Gefahr kann jedoch mit nur wenigen Nachrüstungen von Übertragungsleitungen begegnet werden. PV-Batterien und DSM können dieses Risiko sogar noch weiter verringern und die Systemsicherheit stärken.

Die Nexus-e Plattform ist ein einzigartiges und leistungsstarkes Instrument zur Quantifizierung eines breiten Spektrums von Auswirkungen auf mögliche zukünftige Pfade des Schweizer Energiesystems. Zunächst einmal kombiniert sie Bottom-up- und Top-down-Energiemodellierungsansätze und stellt damit einen breiteren Rahmen des energiewirtschaftlichen Systems dar. Diese Kombination berücksichtigt die Komplexität und das Zusammenspiel von Energienachfrage und -angebot, energiewirtschaftlichen Makrofaktoren und energiepolitischen Faktoren über mehrere Zeitskalen und Aggregationsniveaus hinweg. In Bezug auf die modellierten Netzebenen repräsentiert Nexus-e sowohl die zentralisierte als auch die verteilte Ebene des Energiesystems, was es uns ermöglicht, das gesamtschweizerische Flexibilitätsangebot sowohl auf regionaler als auch auf nationaler Ebene ganzheitlich zu bewerten. Zudem ist Nexus-e in der Lage, Simulationen mit einer hohen Zeitauflösung durchzuführen. Die Fähigkeit, die stündliche Dynamik zu modellieren, erlaubt es uns, neue Verhaltensweisen von Wasserkraftpumpen, Batteriespeicher und DSM zu erfassen, was für die Modellierung der kurzfristigen Nachfrage und des Angebots an Flexibilität von entscheidender Bedeutung ist. Mit einer solch umfassenden Darstellung können wir zeigen, dass die Schweiz sowohl die Ziele für den Ausstieg aus der Kernenergie als auch für die erneuerbaren Energien erreichen könnte, während sie gleichzeitig genügend Flexibilität bieten und die Systemsicherheit aufrechterhalten kann.

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. Ce report 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. Ce rapport illustre les capacités de la plateforme Nexus-e.

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 présente les résultats sur la manière dont les technologies centralisées et décentralisées peuvent répondre au besoin croissant de flexibilité du système électrique suisse et comment cela affecte l'exploitation traditionnelle des unités de production d'électricité existantes. Nous utilisons la plateforme Nexus-e pour simuler trois scénarios : Le scénario de base comprend l'évolution prévue des paramètres technico-économiques (par exemple, une durée d'exploitation de 50 ans pour les centrales nucléaires suisses) et le statu quo du cadre législatif et réglementaire suisse (par exemple, les subventions financières pour les installations photovoltaïques). Le scénario « Nucléaire-60 » reflète les discussions sur la sortie du nucléaire et suppose que les centrales nucléaires sont progressivement abandonnées après une durée de vie de 60 ans. Le scénario « Haute Flexibilité » reflète les discussions sur l'impact et la

valeur d'une offre accrue de flexibilité décentralisée dans le système électrique et suppose un coût faible des batteries et un potentiel élevé de gestion active de la demande (demand side management). Il est important de noter que les objectifs d'émissions nettes zéro (pour la Suisse ou les pays environnants actuellement modélisés) ne sont inclus dans aucun des scénarios simulés.

Nos résultats montrent que l'abandon progressif du nucléaire est réalisé parallèlement à des investissements substantiels dans de nouvelles capacités photovoltaïques sans causer de graves problèmes d'équilibre entre l'offre et la demande d'électricité. Cette transition s'accompagne de quelques investissements supplémentaires dans la biomasse et dans les batteries couplées aux installations photovoltaïques, mais aucun investissement n'est nécessaire dans l'énergie éolienne ou dans les batteries de réseau. La fin des subventions à l'investissement après 2030 réduira l'attrait des nouvelles capacités photovoltaïques en 2040, mais la baisse des prix de l'énergie photovoltaïque stimulera les installations photovoltaïques en 2050. En 2050, le photovoltaïque couvrira la plus grande partie (32,6-35,5%) de la consommation d'électricité, suivi par les barrages hydroélectriques (26,0-28,3%) puis par l'hydroélectricité au fil de l'eau (15,9-17,4%). En outre, avec la sortie du nucléaire, les importations deviennent un élément important de l'approvisionnement en électricité en Suisse, fournissant jusqu'à 5,7% de la demande en 2050. Cependant, la période entre 2030 et 2040 est considérée comme critique car la capacité photovoltaïque stagnante ne peut pas remplacer complètement l'abandon du nucléaire, ce qui entraîne des importations nettes nettement plus élevées, jusqu'à 16,5% de la demande annuelle. Veuillez noter que tous les résultats présentés dans ce rapport sont soumis à des incertitudes et des hypothèses notables. En outre, les scénarios sont illustratifs et les résultats doivent être interprétés comme indiquant des différences de tendances entre les scénarios et non comme des prédictions. Par conséquent, nous ne prétendons pas que le cadre législatif et réglementaire actuel soit suffisant pour atteindre les objectifs en matière d'énergies renouvelables.

Compte tenu de la transition des capacités nucléaires aux capacités photovoltaïques, il existe un besoin croissant de flexibilité sur différentes échelles de temps, allant d'une flexibilité saisonnière à infra-horaire. En utilisant une représentation complète du système énergétique, la plateforme Nexus-e évalue comment ces besoins de flexibilité sont satisfaits, à savoir par une combinaison des composantes suivantes : capacités du parc de production centralisée suisse, importations et exportations, et capacités supplémentaires dans le réseau de distribution. Premièrement, la saisonnalité de la charge nette augmente avec le niveau de pénétration du photovoltaïque, ce qui indique le besoin d'une plus grande flexibilité saisonnière, à laquelle répond une plus grande dépendance saisonnière aux importations nettes et aux barrages hydroélectriques. Deuxièmement, le profil de plus en plus dynamique de la charge nette sur une base horaire et journalière, qui souligne la nécessité de disposer de capacités de flexibilité à croissance rapide, est principalement couvert par les changements rapides des importations et des exportations et des barrages hydroélectriques. Dans une moindre mesure, le pompage-turbinage, l'hydroélectricité au fil de l'eau, les batteries couplées aux installations photovoltaïques et la maîtrise de la demande en énergie (demand-side management) réagissent également rapidement pour contribuer à fournir l'approvisionnement nécessaire. En outre, une part plus importante de batteries couplées aux installations photovoltaïques et de ressources de maîtrise de la demande en énergie permet de lisser la charge horaire nette et donc de réduire la dépendance à l'égard des importations et des exportations pour la flexibilité horaire. Troisièmement, les réserves tertiaires nécessaires pour équilibrer les écarts infra-horaires augmentent d'année en année à mesure que de nouveaux investissements dans le secteur photovoltaïque sont réalisés et sont alimentés par les capacités de production suisses « dispatchable ». Quatrièmement, l'augmentation de la part des unités « non-dispatchable » a un effet négatif sur la sécurité du système et contribue ainsi au risque de défaillances systémiques, mais ce risque peut être géré avec seulement deux extensions de lignes de transmission. Les batteries couplées aux installations photovoltaïques et la maîtrise de la demande en énergie peut réduire encore plus ce risque et améliorer la sécurité du système.

La plateforme Nexus-e est un outil unique et puissant permettant de quantifier un large éventail d'impacts concernant les possibles futures voies du système énergétique suisse. Tout d'abord, elle combine des approches de modélisation énergétique ascendante et descendante et représente donc un champ d'application plus large du système économico-énergétique. Cette combinaison tient compte de la complexité et de l'interaction entre la demande et l'offre en énergie, des facteurs macro-économico-énergétiques et des moteurs de la politique énergétique à de multiples échelles de temps et de niveaux d'agrégation. En ce qui concerne le niveau des réseaux modélisés, Nexus-e représente à la fois les niveaux centralisés et décentralisés du système énergétique, ce qui nous permet d'évaluer de manière globale l'offre de flexibilité dans toute la Suisse, à l'échelle régionale et nationale. De plus, Nexus-e est capable d'effectuer des simulations à haute résolution temporelle. La possibilité de modéliser la dynamique horaire nous permet de saisir les nouveaux comportements des pompes hydrauliques, de la maîtrise de la demande en énergie et des systèmes de stockage sur batterie (battery storage systems), ce qui est essentiel pour modéliser l'offre et la demande de flexibilité à court terme. Avec une représentation aussi complète, nous sommes en mesure de montrer que la Suisse pourrait atteindre à la fois les objectifs de sortie du nucléaire et les objectifs en matière d'énergie renouvelable tout en fournissant une flexibilité suffisante et en maintenant la sécurité du système.

Contents

Abbreviations

AC	alternating current
AT	Austria
BFE	Bundesamt für Energie
BSS	battery storage system
Cascades	Network Security and Expansion Module
CC	combined cycle
CCDF	complementary cumulative distribution function
CentIv	Centralized Investments Module
CGE	computable general equilibrium
CHP	combined heat and power
CO_2	carbon dioxide
DE	Germany
DistIv	Distributed Investments Module
DNS	demand not served
DSM	demand-side management
DSO	distribution system operator
eMark	Electricity Market Module
ENTSO-E	European Network of Transmission System Operators for Electricity
EU	European Union
FB	flow-based
FOM	fixed operation and maintenance
FR	France
GDP	gross domestic product
GemEl	General Equilibrium Module for Electricity
GEP	generation expansion planning
IT	Italy
LCOE	levelized cost of electricity
MILP	mixed-integer linear programming
NTC	net transfer capacity
OM	operation and maintenance
PV	photovoltaic
RES	renewable energy source
RoR	run of river
SC	simple cycle
TYNDP	ten-year network development plan
UFLS	under-frequency load shedding
VOM	variable operation and maintenance
WACC	weighted average cost of capital
WECC	Western Electricity Coordinating Council

List of Figures

List of Tables

1 Introduction

The future Swiss power system, which is envisioned in the Swiss Energy Strategy 2050, has to overcome the following challenges: enabling deep decarbonization, the integration of a higher share of renewables and distributed supply, the phase-out of nuclear power stations, achieving improved energy efficiency, and maintaining system security and resilience. This transition of the energy sector will not only take place in Switzerland but also in other European countries and the transition path chosen may differ for every country. Some countries (e.g., Germany and Switzerland) will exit nuclear power generation; other countries are pursuing a strategy that still includes nuclear power (e.g., France, U.K., Finland, Hungary, Czech Republic). However, the impacts of a transforming electricity sector are evident in Europe: First, there is currently a reducing interest in new investments for traditional production units such as hydropower. This is partly due to over-capacities in Europe and increasing shares of renewable energy source (RES) with close-to-zero marginal costs. Second, there is a common understanding that distributed energy production might play a larger role in the future energy system, either by substituting or complementing traditional production units. The result would be a combination of both – centralized and distributed – technologies. Finally, larger shares of RES will introduce higher variability and uncertainty into the system which needs to be matched with increased flexibility. Both centralized power units (e.g., flexible gas-fired units or hydropower) and emerging distributed technologies (e.g., local storage) might provide flexibility in a future electric power system. We do include conventional thermal generators as candidate units on both the transmission and distribution system levels since the scenarios we are simulating do not reflect a Net Zero future in Switzerland or the surrounding countries.

Flexibility has always been an important requirement for balancing supply and demand in power systems. However, to enable the shift to a more distributed and decarbonized energy system, flexibility is increasingly required across a range of timescales [1]. The short-term flexibility provision (sub-hourly and hourly) balances the deviations in the actual electricity demand and generation and supports system stability and frequency control, for example, in case of an unexpected loss of generator or consumer. The long-term flexibility provision accounts for the daily, weekly, and seasonal needs for generation or oversupply because of outages, weather conditions, or seasonal changes.

Today, conventional power plants are still the predominant sources of flexibility in European power systems. They provide flexibility by rapidly changing their power output or perform frequent start-ups and shut-downs. Particularly in Switzerland, hydro power plants, such as pumped hydro or hydro storage, can provide a large range of flexibility services. Although wind and solar are considered as the key driver of new flexibility requirements, to some extent they could also provide cost-effective flexibility services such as curtailment [2]. Additional sources for flexibility are electricity storage technologies, which can absorb electrical energy and then later return it as electrical energy. They can serve multiple applications, which allows them to not only tap into different value streams but also combine different risk exposures [3]. In particular, battery storage systems, due to their projected cost declines [4], are likely to play a crucial role for short-term flexibility in future power systems. Distributed energy resources such as photovoltaic (PV), heat pumps, and electric vehicles can also be aggregated and leveraged to provide system flexibility at local and bulk power system level. Also demand-side management, while mostly used for peak demand reduction in the past, could provide other flexibility services such as avoiding short-term distribution network congestion and redispatch costs. At country level, imports and exports are also essential flexibility providers, as the resources of other countries can be utilized via cross-border transmission grids. One of the key limiting factors for the utilization of flexibility resources today are transmission and interconnection bottlenecks as well as limitations of market products.

Besides technical challenges, the shift towards a nuclear phase-out and distributed energy system also has macroeconomic impacts. New investments into the energy system are likely affecting the gross domestic product (GDP) and economy-wide investments. In addition, the investments in renewable energies reduce the carbon-footprint of electricity supply, exemplifying the potential environmental benefits of the transition.

Modeling the transition to a future electric power system including high shares of renewable energy and flexible resources requires capabilities to represent the interdependencies between policy-making, macro-economic development, energy infrastructure expansion, market behavior, environmental impact, and security of supply. Existing energy modeling practices share two main limitations that prevent a more comprehensive representation of the energy system. First, they tend to focus on only one or a few components, sectors, and layers of the energy system in isolation, choosing to ignore the interdependencies with all other components of the energy system. Instead, they use the other parts of the energy system as exogenous inputs, ignoring important feedback loops such as the interplay between distributed and centralized investments in energy resources. Such narrow-focused modeling practices limit the scope of the analyses and might result in inconclusive implications and policy recommendations. Second, model-based analysis is further hampered by a lack of transparency often turning the analysis into a 'black box'. This impedes the transfer of knowledge, particularly across disciplines, and thus prevents a collective learning process within the energy modeling community. Both limitations result in current modeling practices that do not account for the complexity inherent in the electric power system and thus might fail to identify most-effective decarbonization strategies.

To address both limitations, we developed the Integrated Energy Systems Modeling Platform (Nexus-e), a platform that combines bottom-up and top-down energy modeling approaches and thus represents a broader scope of the energy-economic system at a regional and national scale. The platform thus accounts for the complexity and interplay of energy demand-supply, macro energy-economic factors, and energy policy drivers across multiple time-scales and levels of aggregation. Nexus-e is based on modularity (i.e., integrate cross-disciplinary, new and existing modules through a flexible structure to capture and develop know-how), transparency (i.e., openly available to researchers, industry, and partners to harmonizes viewpoints, data, and modeling assumptions)[1], and defined interfaces between models (i.e., capture interdependencies between different layers and sectors of the energy system). In Nexus-e, by representing both levels of the electricity system, centralized and distributed, we can holistically assess the supply of flexibility across Switzerland for possible future scenarios. This novel and broad modeling scope is capable of analyzing the rich and varied flexibility applications needed for the *whole* electricity system along with how these applications are supplied among all sources of flexibility, both centralized and distributed.

Using the Nexus-e platform, this report analyses the mutual influences of large-scale centralized and small-scale distributed flexibility providers in light of a transition of the electricity sector. It aims to answer how different flexibility technologies will be deployed and how they influence the whole energy system. In particular, this report answers the following research questions:

- *What are potential pathways for the future Swiss electricity system?*
- *What is the need for flexibility in the projected Swiss electricity system?*
- *Who provides the required flexibility?*
- *What are the macroeconomic and environmental impacts of the future Swiss electricity system?*

To answer the research questions, we simulate three scenarios. First, the Baseline scenario includes the projected development of techno-economic parameters, for example, the runtime of 50 years for nuclear power plants. It also represents the status quo of the Swiss legislative and regulatory framework, such as the financial subsidies for PV systems. We use [5] for the development of capacity developments of neighboring countries and the carbon dioxide (CO_2) price. The Nuclear-60 scenario reflects the discussion on the nuclear power exit. It builds upon the baseline scenario but assumes that nuclear power plants are phased-out with a lifetime of 60 years, instead of the 50 years in the Baseline scenario. As the current Swiss law allows existing power plants to continue to operate as long as they fulfill the

[1] Currently, details of the Nexus-e platform can be found in the module documentation report along with other reports provided to Bundesamt für Energie (BFE). We are also in the process of evaluating options for providing access to the Nexus-e platform for interested parties (i.e., researchers, industry, and other stakeholders.

conditions for safe operation, the accurate prediction of the phase-out of the nuclear power plants in Switzerland is challenging. The High-Flexibility scenario reflects the discussion on the impact and value of an increased supply of distributed flexibility in the power system. It also builds upon the Baseline scenario but assumes lower battery costs and higher demand-side management potential. It is important to note that net-zero emissions targets (for Switzerland or the surrounding countries currently modeled) are not included in any of the simulated scenarios.

The remainder of the report is structured as follows. Section 2 provides an overview of the methods/modules that the Nexus-e platform utilizes: introducing the platform (Section 2.1) and the individual modules (Section 2.2), highlighting the modeling of flexibility (Section 2.3), outlining the module calibration and validation (Section 2.4), and concluding with the system setup and input data (Section 2.5). Section 3 motivates and describes the three simulated scenarios. Section 4 presents the results for the pathways for the future Swiss electricity system (Section 4.1), the system's need for flexibility (Section 4.2), the system's supply of flexibility (Section 4.3), and the socio-economic impact of the Swiss electricity system (Section 4.4). Finally, Section 5 concludes and outlines directions for future research in energy system modeling.

2 Method

This section provides a brief overview of the Nexus-e energy systems modeling platform (Section 2.1), the individual modules (Section 2.2), the modeling of flexibility (Section 2.3), the validation and calibration of the modules (Section 2.4), and the input data (Section 2.5). The full documentation of the Nexus-e modeling platform comprises the following reports as separate documents:

Overarching reports:

- Scenario Results (this report)
- Simulation Framework and Interfaces
- Validation and Calibration of Modules
- Input Data and System Setup

Individual module reports:

- GemEl Module Documentation
- CentIv Module Documentation
- DistIv Module Documentation
- eMark Module Documentation
- Cascades Module Documentation

Within this report, i.e., Scenario Results, only a condensed version of some of the other reports is presented.

2.1 The Nexus-e platform

The Integrated Energy Systems Modelling Platform (Nexus-e) represents the Swiss energy-economic system at a regional and national scale, including the interplay of energy demand and supply, the macroeconomic environment, and energy policies. It aims to identify cost-optimal investments and operation in centralized and distributed energy resources, taking into account their socio-economic impact and changes in the security of supply. The platform combines bottom-up and top-down energy modeling approaches, across multiple timescales and levels of aggregation. It allows for modularity so that different combinations of modules can be combined and used for analyses.

Figure 1 provides an overview of the Nexus-e platform. It integrates five modules (i.e., General Equilibrium Module for Electricity (GemEl), Centralized Investments Module (CentIv), Distributed Investments Module (DistIv), Electricity Market Module (eMark), Network Security and Expansion Module (Cascades)) that can communicate with each other through hard-coded, automated, and well-defined interfaces within three loops (i.e., Investments, Energy-Economic, Security). As inputs, the platform uses data for the Swiss power system, including grid data, generator data, time-series data (e.g., electricity demand data), and the energy-specific input-output table. Additionally, it includes data for neighboring countries, including generator data per technology and hourly electricity demand. As outputs, the platform provides the installed power generating capacities, the costs of these investments, the operating schedules and costs of generators, electricity prices, an assessment of the system security, suggested transmission grid expansions, socio-economic impacts, and CO_2 emissions.

We use the platform to analyze future scenarios of the Swiss power system (see Section 3), where each consists of four years, which we refer to as scenario-years. To simulate a given scenario-year, the Nexus-e platform runs the following steps: First, in the Investments loop, CentIv and DistIv conduct a co-

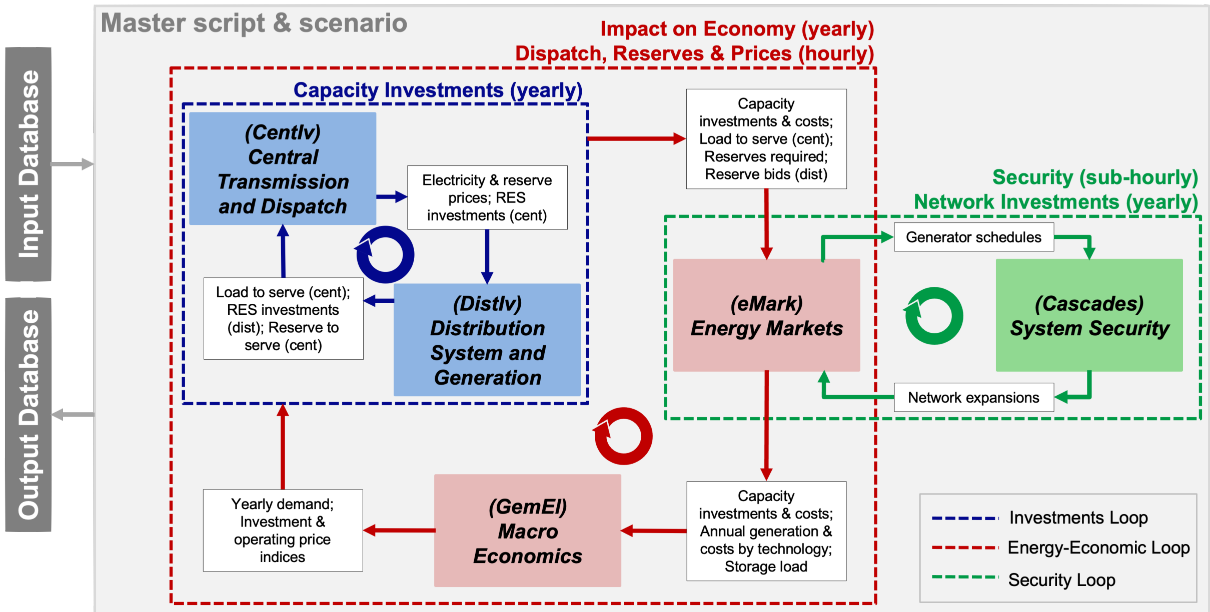


Figure 1: Overview of the Nexus-e platform including the five modules (colored boxes), the three 'loops' (colored arrows), and the interfaces (white boxes). Note that for visualization purposes some of the interfaces are combined in the figure.

ordinated generation expansion planning (GEP) process at the transmission and distribution system levels, accounting for benefits and costs of investments in both systems. Second, in the Energy-Economy loop, eMark uses the resulting investment decisions to determine the hourly generator schedules and operating expenses. Then, it hands over the results to GemEl, which re-establishes the macroeconomic equilibrium and adjusts the electricity demand. In case the adjusted annual demand increases by more than 2%, it begins a new iteration of the Energy-Economic loop, starting with the investment decision by CentIv and DistIv. Otherwise, the Energy-Economic loop reaches convergence. Third, after the Energy-Economic loop converges, the Security loop starts where eMark sends hourly generator schedules to Cascades, which subsequently assesses the system security and proposes investments in the transmission system.

Within each of these loops, modules send data through interfaces. To do so, each module contains functions that extract the relevant results, package them in a specific structure, and send this data structure to other models. Therefore, when a module begins its simulation process, it calls the functions of all modules from which it requires data. Each of these functions extracts, packages, and sends back the required data to the module that has started its simulation process. In one interface, a model can call functions of multiple modules. For example, in the Investments-eMark interface (part of the Energy-Economic loop), both CentIv and DistIv send data to eMark. To allow for dependencies between the scenario-years, the Nexus-e master script establishes a connection with a database that contains the input data and creates a one-to-one copy of it. At the end of each scenario-year simulation, the master script updates the copy and adds all results that are relevant for later scenario-years. This script gathers results from the modules using functions defined within each module that act analogous to the interface functions that are used to send results between modules.

More information on the Nexus-e simulation platform including loops and interfaces can be found in the "Simulation Framework and Interfaces" report.

2.2 Individual modules

As already mentioned above, the Nexus-e Platform consist of the following five interlinked modules (the module documentation reports provide detailed descriptions of each module):

GemEl: The GemEl module is a detail-rich computable general equilibrium (CGE) model for Switzerland based on the most recent actual economic data available. The model simulates the markets for all goods and services produced and demanded. It can be used for almost any policy measure and especially for evaluating the efficiency of energy policy measures as well as new investments in electricity generation. The model also can keep track of emissions and the yearly produced and demanded electricity. The GemEl module simulates the Swiss economy with over 77 sectors using a yearly resolution. All goods and factors markets are cleared simultaneously as GemEl is formulated as a system of non-linear equalities and inequalities resulting in the equilibrium of demand and supply along with the market price for each good.

CentIv: The purpose of the CentIv module is to co-optimize generation investment and operational decisions on the transmission system level for a target year. The module provides results with high temporal (hourly) and spatial (nodal) resolution from the perspective of a centralized decision-maker. In its formulation, the module includes detailed dispatch, reserve, and investment constraints for a wide range of flexibility providers. It gives insight into how centralized power systems could evolve and cope with the increasing variability in distributed energy demand and generation. CentIv has an essential role within both the investment and energy-economic loops of the Nexus-e framework.

The CentIv module co-optimizes operational- and capacity-investments decisions at the transmission system level with an hourly resolution for every other day of a given target year. The overall objective of the optimization problem is to minimize the sum of the investment and dispatch costs of all generation and storage technologies while matching demand and supply and meeting reserve requirements. We include linear transmission network constraints to position candidate units precisely in the system and consider the import/export behavior with other interconnected zones by modeling, albeit at a very aggregated level, their generation as part of the optimization problem.

DistIv: The DistIv Module aims to jointly optimize the investments and operations of distributed energy resources over one year using an hourly resolution. Given the electricity prices from the CentIv module, the model trades-off between investing in local distributed energy resources and purchasing electricity from the transmission grid. The trade-off is realized by jointly optimizing the investments and operations of a distribution system considering different types of storage units, variable and dispatchable generation units, and demand-side management, while taking the exchange of energy and reserve with the transmission system into consideration. To reduce the computational time, the module simulates every other day instead of all hours of the year.

eMark: The purpose of the eMark module is to simulate a market-based clearing of supply offers and demand bids for both electricity and reserves. This module mimics the current sequential structures and timing employed to clear all electricity market products. Additionally, eMark applies realistic constraints for intra-zonal trading that reflect the current market coupling mechanisms. The module provides high temporal (hourly) resolution and moderate spatial (zonal) resolution equivalent to those of the existing market processes. eMark has the critical role in the Nexus-e framework to provide a market-based perspective and enable assessments of future market structures.

The eMark module simulates the energy and reserve market clearing over one year 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 module clears the future market for one month 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 module clears the balancing market for the first week of the same month. All required reserves are supplied over this week (similarly, each reserve requirement is constant over all hours of one week). Third, the module clears the day-ahead market 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 repeats for each day of the week followed by a repetition of the balancing and day-ahead market clearing for the next weeks and, in turn, the future market clearing for the next month. This sequential process continues until the module completes each day, week and month.

Cascades: The purpose of the Cascades module is to, first, assess the system security by testing the capability of a power system to withstand disruptions due to component failures; and, second, to provide a transmission system expansion plan if a target level of security is not satisfied. The Cascades module comprises two models, i.e., a cascading failure simulations model and a transmission system expansion planning model.

The cascading failure simulations model assesses the system security. The model is initialized with sets of contingencies, which are potential critical failures that may trigger cascading events. After an initial failure is introduced, the model identifies island operations and blackout conditions in the power system. Furthermore, the model simulates load-frequency control by deploying available generation reserves. Moreover, the model simulates automatic load shedding in case of system frequency deviations beyond a safety threshold or bus voltage magnitudes below a tolerable limit. To calculate the power flows and bus voltages, the model utilizes an alternating current (AC) power flow algorithm. In addition, the model disconnects transmission elements (lines and transformers) due to overloads, i.e., violation of the branch power ratings. The transmission system expansion planning model relies on two importance lists, which rank the branches from most important to least important with respect to different criteria. Based on the rankings, expansion upgrades are proposed and, in turn, the improvement in the security level is calculated. The branch upgrade that provides the best security improvement is added to an expansion list. The process is iteratively repeated until a predefined level of security is satisfied, or an expansion budget is reached.

2.3 Modeling flexibility

The flexibility of a power system alludes to the capability of the system to cope with rapid changes in supply or demand and preserve seamless service within transmission network operating limits. Flexibility has always been a critical requirement for maintaining power system balance, for example, to overcome unanticipated contingencies and demand forecast errors. However, to enable the shift to a more decentralized and decarbonized energy system, flexibility is increasingly required across a range of timescales [1]. Figure 2 provides an overview and example of flexibility-related issues addressed across all time-domains from sub-hourly to seasonal along with an indication of the Nexus-e modules that capture the different issues.

The shortest flexibility timescale, sub-hourly, helps to provide services for system stability and frequency control, for example, to help balance the unexpected loss of a generator or a consumer as well as to balance deviations between the actual and forecasted electricity demand or supply. The next flexibility timescale, hourly, is necessary to follow the expected pattern of demand and non-dispatchable supply (i.e., wind or PV) over the day, for example, to match a rapidly changing net demand occurring as high PV generation dissipates in late afternoon and demand increases toward early evening. More intermediate length flexibility, daily, helps to address the unit scheduling and generation dispatch differences from day-to-day, for example, between a cloudy or sunny day or between a workday and weekend day. The long-term, seasonal flexibility, helps to bridge seasonal variations in generation and demand, for example, due to hydropower availability, summer solar intensity, or winter heating demand. The following subsections describe how the modules within the Nexus-e framework work together to address the range of flexibility timescales.

	Sub-Hourly	Hourly	Daily	Seasonal
Issues addressed	System stability and frequency control	Changes in the supply/demand	Generation dispatch and operation scheduling	Seasonal variable generation and demand
Example Issues	1) Unexpected loss of system component such as a generator or a consumer 2) RES generation forecast errors	1) Rapid ramping up between sunny afternoon and evening peak demand	1) A very sunny day followed by a cloudy day	1) Hydropower availability 2) Increasing heating demand in winter months
Focus of module	CentIv, eMark, Cascades	CentIv, DistIv, eMark, Cascades	CentIv, DistIv, eMark	CentIv

Figure 2: Power system flexibility covers a broad number of critical issues across a range of timescales. The Nexus-e modeling platform captures these varying needs for flexibility among the interfaced modules. (Adopted from IEA [1])

2.3.1 Sub-hourly

Although the Nexus-e platform does not include power system dynamic aspects that address extremely short-term frequency stability issues, several modules represent the procurement and deployment of reserves that are needed to compensate for sub-hourly effects of unit outages, load variability, and short-term forecast errors. Traditionally, capacity reserves provide the necessary backup power to cover the loss of a generator or a load as well as for balancing the random variability in demand. As more weather-dependent RES resources are integrated, utilizing reserves to compensate for the forecast errors that these resources introduce, is becoming more ubiquitous. To account for this increasing need for flexibility, CentIv utilizes a method previously developed in [6] to quantify the additional reserves needed for any amount of newly installed wind or PV capacity. Details of this method can be found in Appendix A. Additionally, within the dispatch process of both the CentIv and eMark modules, the procurement of these reserves is included to ensure that enough generating capacity is available for supplying the reserves as well as the electricity demand.

The Cascades module also addresses sub-hourly flexibility by simulating the short-term response of under-frequency load shedding (UFLS) along with the deployment of reserves that occur in response to frequency deviations. The system frequency and stability, is affected by systemic failures (contingencies) and the subsequent cascading outages that could ensue. As part of the process to assess the flexibility of the transmission network to handle such contingencies, Cascades simulates the progression and system response to component failures. If the frequency deviation exceeds the predefined margins UFLS is performed. Otherwise, the load-generation balance is restored by frequency control, i.e., primary frequency control responds within a few seconds (active up to 30 seconds), secondary frequency control responds between 15 and 30 seconds (active up to 15 min), and tertiary frequency control responds after several minutes (activated within 15 min). Overall, the system uses the available generating reserves to restore the system frequency. Therefore, the amount of available and dispatchable (flexible) units and their location in the grid will affect system stability and determine if all loads will continue being supplied. In general, the lack of flexibility in the power system will have a negative effect on the system security and, thus, will contribute to the risk of systemic failures. Indeed, the system security is influenced by multiple factors, including the generation mix, the share of dispatchable units in the mix, their ramp rates, the location of the units in the grid, the transmission capacity, the demand, and the imports/export, all of which are captured by the Cascades module.

2.3.2 Hourly and daily

In this work, we combine the hourly and daily flexibility timescales since both utilize the operating capabilities of available generators in the dispatch to balance the various issues that can cause supply and demand imbalances. Within these timescales, hourly flexibility is necessary to provide controllable generation resources that can respond to rapid changes in the demand or supply from one hour to the next. The hourly net load, which is defined as the system load minus production from non-dispatchable RES generators[2], represents the demand profile that all dispatchable (i.e., controllable) generators must match. In this work, we use the net load to represent the need for flexibility on the hourly timescale. Several flexible solutions can be useful to match a rapidly changing net load, including: responsive and fast ramping generators, adjustable imports or exports through interconnections, large or small energy storage units, demand-side management (DSM), aggregated distributed resources, or curtailment of non-dispatchable generators. Historically, depending on weather conditions, the net load could be rapidly changing as demand peaks in the hot summer afternoon or as winter demand peaks in both morning and evening. In the future, the transition toward non-dispatchable RES, in particular PV resources, introduces significantly larger and more rapid fluctuations to the hourly net load, as shown e.g. in the California 'duck curve' [7]. Similar to this California example, the Swiss net load curves shown in Section 4.2.2 highlight the significance of the expected changes for hourly flexibility in a future with significant shares of PV. Within Nexus-e, CentIv, DistIv, and eMark collectively model the use of all available flexible resources that could be used within the hourly dispatch process to constantly match the Swiss net load.

Moving to the longer timescale, daily flexibility is needed to overcome differences from one day to the next that can arise, for example, because one very sunny day is followed by a cloudy day. Another common example of daily variations is a weekday with higher demand followed by a weekend day with lower demand. At this timescale, planning for the commitment of dispatchable units and their operating schedules is necessary to provide available capacities over longer time frames. Again, a range of resources can provide such flexibility, including: conventional generators, hydro dams, large-scale storage units, and imports or exports. In this work, we use the average net load from day-to-day to gauge the need for flexibility on the daily timescale. Similar to the hourly flexibility, the CentIv, DistIv, and eMark modules all address issues related to daily flexibility. Each module includes the generator dispatch process to optimize the use of dispatchable capacities across days to overcome any differences in system conditions from one day to the next.

2.3.3 Seasonal

The longest flexibility timescale, seasonal, is required to bridge the long-term cyclical variations in generation and demand across the year. Strong seasonal weather conditions, such as hot summers or cold winters, can drive the demand for electricity high in particular times of the year. However, for Switzerland, the most critical seasonal variation is the water availability and production from hydro storage generators. For these units, excessive water inflows in spring and summer along with limits to storage

[2] Net Load = Load - (Wind + PV production). In this work we do not subtract the production of hydro run of river (RoR) units from the load as part of the net load calculation. This assumption is consistent with the traditional calculation. Additionally, while it is normal to consider RoR production as non-dispatchable based on river flows, the actual complexity of how RoR plants can operate is much more robust. Furthermore, in this work, the RoR capacity is not changing across scenarios or in future years, and thus, does not have any additional affect on the net load.

volumes compels high production levels in summer. However, their seasonal operation is also motivated by higher electricity prices in winter, which provide greater earning potential. As part of Nexus-e, CentIv addresses seasonal flexibility by capturing all long-term influences in a single yearly optimization. This optimization uses knowledge of the full year to set hourly operation schedules that account for seasonal aspects related to hydro storage units, solar production, and demand. The result includes optimal use of the Swiss hydro dams and their connected storage reservoirs[3].

2.3.4 Centralized versus distributed flexibility

In terms of assessing flexibility providers, great attention has been given to large-scale technologies at the transmission grid level, particularly to hydro systems [8, 9]. However, this centralized, top-down approach tends to ignore the heterogeneity of load profiles and disregards other potentials, such as demand response and distributed storage [10]. This is not in line with the objective to develop a smart grid as it merely addresses the supply side issues and shows a limited understanding of distributed potentials [11].

To overcome this limit, the bottom-up perspective used by DistIv can provide valuable insights into how distributed flexibility providers can enhance the responsiveness within the distribution system and thus improve the flexibility of the overall energy system. But, researching the role of distributed flexibility providers cannot be accomplished by focusing on distribution grids studies alone. In this sense, to analyse interactions between centralized and distributed flexibility providers, modeling both centralized and distributed levels of the system is indispensable. Hence, in Nexus-e we combine modules that represent both levels of the energy system to holistically assess the supply of flexibility across Switzerland for possible future scenarios. This novel and broad modeling scope that is capable of analyzing the rich and varied flexibility applications needed for the *whole* electricity system along with how these applications are supplied among all sources of flexibility, both centralized and distributed. In short, to assess the role of flexibility providers, the project considers their impacts on 1) conventional capacity investments, 2) supporting RES integration, 3) electricity network security, and 4) the system operation and dispatch. Since the role of flexibility providers influences various layers and components of the energy system, the Nexus-e framework represents bottom-up technologies starting from the demand side (distributed generation systems) and analyses the mutual benefits with large-scale flexibility options (e.g., use of hydropower or expansion of gas-fired power plants). In the context of this work, we look at scenarios in which net-zero emissions targets are not included, therefore, we do include conventional thermal generators as investment options.

2.4 Module calibration and validation

The objectives of the validation and the calibration of the Nexus-e modules is to develop trustworthy and high-fidelity modules as well as to adjust the modules to better represent the complexity of the involved real systems and processes. The report on Validation and Calibration of Modules details the processes for the Nexus-e modules. In the following, we summarize the validation or calibration in each of the modules:

GemEl: GemEl uses the 2014 Swiss energy-specific input-output table [12]. However, the top-down economic equilibrium in GemEl is affected by the new power generation investments, the changing generation mix, and the associated costs for the electricity system in the future years. Therefore, GemEl performs a recalibration of the generation technologies and distribution sector to create

[3] Nexus-e does not, however, simulate extreme years or conditions that would allow assessments of capacity or hydro adequacy.

a new starting point for electricity demand. While this process is a type of calibration, it is not a comparison to historical data. It is described in the GemEl module documentation report and the simulation framework report.

CentIv: While CentIv co-optimizes investment and operational decisions, the CentIv calibration focuses on the latter and compares modeled and historical operation in 2015. It aligns values on electricity generation by technology type, import-export flows, and seasonal hydro storage profiles. Improving the modeling of unit operation also results in more realistic investment decision-making as the operation of existing power units affects new investments.

We adjust the model outputs to historical values in five steps: First, we convert to an aggregated representation of the neighboring countries' networks by 1) performing a network reduction; and 2) fine tuning the aggregated line reactance within the neighboring countries to correctly recreate cross border flows. Second, we adjust the hydro inflow profiles (dam and pump) in Switzerland and the neighboring countries. With this calibration step, we achieve a more realistic generation profile from hydro dam units and improved the discharging and charging behavior from pump-storage hydro plants. Third, we adjust the capacity factors of nuclear and biomass units to align their modeled and historical annual electricity production values. Fourth, we adjust the hourly load profiles of the neighboring countries by subtracting the hourly net exports (excluding the electricity trade with any of the five modeled countries). With this calibration step, we prevent excessive generation capacity within the four neighboring countries modeled. Fifth, we adjust the generators' variable operation and maintenance (VOM) cost, which is necessary to help overcome modeling limitations from aggregated generators in non-Swiss regions with constant variable costs. This process is closely linked to the adjustment of network reactances because both impact the injections and splitting of power flows around and through Switzerland. Overall, this calibration process produces results such as production by technology type, import and export flows, and hydro storage seasonal profiles that coincide well with the historical 2015 data, giving us confidence in the ability of our models to accurately predict how these outputs change in future scenarios. The calibration of CentIv and eMark is performed together because they both simulate the dispatch of all centralized generating units.

DistIv: DistIv identifies cost-optimal investments in distributed energy resources, taking into account financial aspects in the objective function and assuming a single investor. However, particularly in distribution systems, investors not always take an economic perspective and might invest in a technology, although it is not economically viable, or do not invest even though it is. Also, investors in the distribution system are very heterogeneous and differ substantially, for example, in financial parameters such as their weighted average cost of capital and desired payback periods. Consequently, results for cost-optimal investments might deviate from historical values. Therefore, we validate DistIv by comparing the simulated results and the historical values in 2018 and gain an understanding of the deviations between them. The insights gained enable us to perform a rationality check on the regional investment results that shows they agree with the factors that drive PV investments (these factors, such as electricity price and solar irradiation, vary regionally).

eMark: We calibrate the dispatch results from the market clearing processes in eMark (i.e., electricity generation by technology type, import-export flows, hydro storage levels) by adjusting the calibration parameters (i.e., network reactances, hydro inflows, generator costs, etc.). The calibration of eMark is performed together with CentIv as they both simulate the dispatch of all centralized generating units. The calibration process for both modules is described in the paragraph for CentIv above.

Cascades: We validate Cascades by comparing the simulation results against the historical blackout (demand not served (DNS)) data of a power system. This comparison provides an estimate of the capability of the algorithm to capture the overall behaviour of the system when single or multiple failures of transmission components occur. Moreover, we perform calibration to achieve a better agreement between the simulation and the historical data. The calibration of Cascades is performed by optimal selection of input parameters (i.e., line power ratings) using a meta-heuristic based optimization.

For demonstration purposes, we calibrated the module against historical data using the reduced Western Electricity Coordinating Council (WECC) power grid (located in the US[4]). Note that the calibrated parameters are not used within the Nexus-e project. We perform this calibration using the WECC system because the DNS statistics of the Swiss power system are not available to us. Hence, the WECC calibration results are used to illustrate how a calibration could be done in case historical data for the Swiss system would be available. For the Swiss system, we can only compute the curve for a particular year, 2015 in this case without actual calibration. Furthermore, we have performed module adjustment (tuning the line ratings, which are defined as the maximum amount of power that lines/transformers should carry) in order to produce a realistic risk curve and avoid initial overloads due to the generation dispatch. This risk curve produced for the 2015 Swiss power system is used to study the deviations of the future scenario-years.

2.5 Input data and system setup

The section gives an overview of the input data for the transmission system (Section 2.5.1) and the distribution system data (Section 2.5.2). The Nexus-e Input Data Report provides more details on all data and sources and the Validation and Calibration of Modules Report provides additional details on aggregation of the neighboring networks.

2.5.1 Transmission system

The Nexus-e framework includes a detailed representation of the transmission system of Switzerland and an aggregated representation of the four neighboring countries (Germany (DE), France (FR), Italy (IT), and Austria (AT)). Figure 3 shows the transmission grid, including planned line upgrades until 2025. We use this transmission system, including the planned upgrades, to simulate the scenario-years 2030, 2040, and 2050, while for 2020 we only include the upgrades that were already completed by then.

For representing the transmission grid, we used data provided by Swissgrid [13] and the European Network of Transmission System Operators for Electricity (ENTSO-E) [14, 15]. We aggregated the fully detailed ENTSO-E network data using a sophisticated network reduction method, which we developed for this project [16]. In the resulting reduced representation, all Swiss cross-border lines going to a neighboring country connect to a single border node, which further connects to the main node of that country through an aggregated line between any two neighboring countries. The neighboring countries are also connected to each other with a single aggregated line. The generator capacities of each neighboring country are placed at the main country node (not at the border node). The line limits of the aggregated lines between Switzerland and the neighboring countries are modified to have transfer capacities that reflect the market-based limits (i.e., net transfer capacity (NTC) or flow-based (FB) limit). Analogously, the aggregated lines connecting the neighboring countries also use modified limits to reflect the market-based transfer capacities. We gathered the data for these limits on market-based transfer capacities from Swissgrid [17] and the ENTSO-E Transparency Platform [18]. We also increase these transfer limits between 2020 and 2050 based on the ten-year network development plan (TYNDP) available from ENTSO-E [14]. In total, the 2020 network model comprises 266 transmission lines, 164 nodes, and 21 transformers. The Swissgrid extensions beginning in 2025 include 67 additional lines, 11 additional nodes, and 5 additional transformers while also removing 52 lines, 2 nodes, and 1 transformer (many of these additional and removed elements are actually upgrades or reroutings of existing elements).

[4]The reduced WECC grid is a meshed transmission system grid with similar size as the Swiss power grid.

For existing Swiss generator capacities and locations, we used data from the BFE [19, 20, 21, 22] and previous studies [6]. Since we do not model the heating sector in Nexus-e, existing combined heat and power (CHP) units operate similar to normal gas-fired or oil-fired power generation units. We do not include CO_2 levy refund for gas-fired CHP plants. Furthermore, we do not include a market premium for hydro power. The generators in the neighboring countries are aggregated to one unit per technology type using data from ENTSO-E [23]. In all scenarios, these generators reflect the installed capacity projections in the period 2020–2050 from [24].

For operational costs, we use data from recent BFE sponsored studies [25, 26] and other European studies [27, 28]. We incorporate adjustments to the fuel and CO_2 portions of the total operating costs using the projections from [24] and we assume constant non-fuel VOM costs, which is consistent with the assumptions of [26][5].

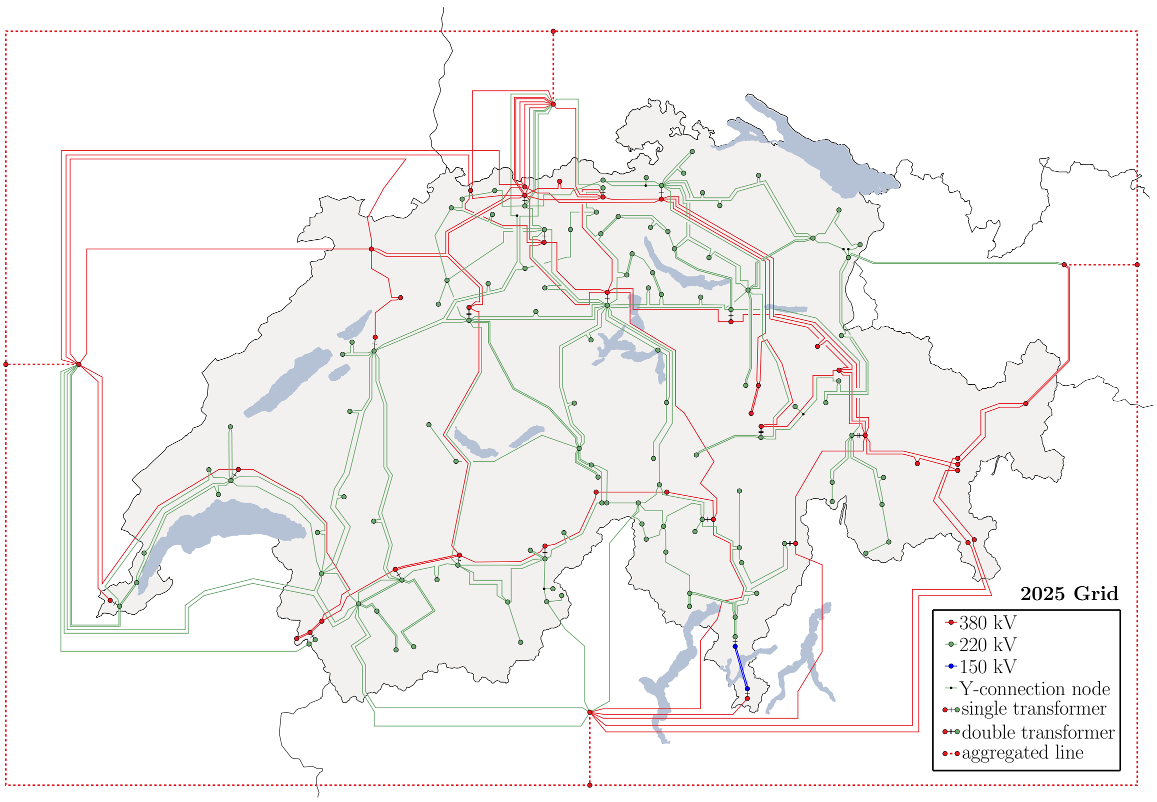


Figure 3: Overview of the 2025 transmission system modeled.

For centralized capacity expansion planning, we include candidate units for gas combined cycle (CC), gas simple cycle (SC), biomass, and wind, as shown in Table 1. For capacities, investment costs, and fixed operation and maintenance (FOM) costs, we use data from [25, 26] and own calculations. It is important to note in accordance with these PSI reports [25, 26], investment costs for these centralized units are assumed constant throughout the scenario-years (see data related to gas-fired power plants in Figure 15.8 of [26] and discussions related to the uncertainty of wind costs in Section 7.3.1 [25] and Section 8.5.5 [26]), and do not include candidate units in the neighboring countries but instead fix future capacities based on the previous European Union (EU) reference scenario from PRIMES [24]. No investment subsidy is included to offset the investment costs for new gas-fired units. The costs of

[5]As indicated in Figure 15.8 in [26], which shows the break-down of the levelized cost of electricity of gas units (both open and closed cycle), the fixed and non-fuel operation and maintenance (OM) portions of the OM costs are constant in the period 2020-2050. A similar trend can be observed in [26] for the coal-fired power plant costs.

biomass reflect current waste incineration subsidies [25, 26], which we expect to continue in the future. The considered subsidies offset a large portion of the investment and operating costs for the candidate biomass units as well as the existing ones. We restrict the total candidate capacity of biomass to account for limited resource availability. We also limit the total candidate capacity of wind power to be in line with the review on the potential of wind power in Switzerland in [26]. Wind candidates are included that in total produce around 4.0 TWh/a, which is also consistent with the Swiss wind energy concept [29]. Due to the uncertainty of future cost projections of wind projects in Switzerland [25, 26], we assume constant investment costs in the period 2020-2050, but also include a sensitivity analysis of wind investments in Section 4.1.5. The current production subsidy (KEV) is not included for wind candidate units since KEV is scheduled to phase out in 2022 and it is unlikely any new wind turbines would get accepted into the KEV before then. We do not consider candidates for new hydro investments because of the need for extensive information about the location and costs for expansion of existing hydro or new hydro units. Therefore, we also do not include investment grants for hydro power. In the scope of this project, we do not include geothermal units as candidates, hence, we do not include subsidies for geothermal. The main reason for not including geothermal capacities was the high level of uncertainty regarding the potential and costs of this technology in Switzerland [25, 26]. Due to this uncertainty, the additional computational burden to simulate geothermal power plants and the researchers' time required to set up all necessary parameters and locations for the candidate units was deemed too high.

Table 1: Investment and FOM costs of candidate units for the transmission system level in Switzerland (2020–2050)

Technology	Investment cost [kEUR/MW/a]	FOM cost [kEUR/MW/a]	Capacity [MW]	Number of Units
Gas CC	58.5	25.0	4200	28
Gas SC	36.1	18.0	700	14
Biomass	124.8	0.0	240	12
Wind	182.4	45.4	1960	7

For the total hourly electricity load, we use data from [30] for Switzerland and from [24] for the neighboring countries. The data from [24], however, only provides annual loads for 2020–2050. Therefore, we scale the 2015 hourly load data from ENTSO-E [31] so that the total annual demand matches the projected totals for 2020–2050 from [24]. These neighboring loads are further adjusted to account for cross-border flows to all other EU countries (e.g., DE-DK, DE-PL) using the 2015 cross-border flow data from ENTSO-E [32]. For the hourly reserve requirements, we use the 2015 data from [33] and calculate additional requirements endogenously when the simulation shows investments in new intermittent RES generators. We derive production profiles for existing PV and wind generators from previous works [6] that included detailed assessments of these RES potentials and generation profiles (this includes profiles for Switzerland and the other regions). As we go into the future, we do not have information or a method to approximate the initial/final storage levels a priori, however both CentIv and eMark require setting the beginning and ending conditions for storages. Therefore, we fix the yearly end levels of all hydro storage reservoirs (i.e., dams and pumped-hydro reservoirs) to the initial levels in 2015 from the BFE [34] and hydro inflows to the calibrated 2015 values derived from BFE [35, 34]. We do not model a Net Zero future for any of the five countries. For the surrounding countries (AT, DE, FR, IT), [24] is used as the main source of capacity development projections. It is important to note that these projections do include significant shares of gas power plants. Additionally in Switzerland, we introduce open/combined cycle gas turbines (without carbon capture) as candidate units.

2.5.2 Distribution system

Nexus-e represents the distribution system on an aggregated cantonal level. While we do not model the distribution grid, we connect the cantonal values (e.g., electricity load profiles) to the nodes of the transmission system. The Investment loop exemplifies this cantonal-node connection: First, CentIv provides to DistIv the nodal electricity load and wholesale prices, along with the Swiss reserve requirements. In turn, DistIv sums the nodal values for each canton and also calculates the cantonal wholesale prices using a weighted average of the prices of all nodes within each canton. The weights are defined as the ratio of the hourly nodal load to the hourly total load in each canton. Similarly, for the reserve requirements, we also use the weighted average. After DistIv identified the cost-optimal investments into distributed energy resources, it sends nodal residual demand and reserve requirements back to CentIv. To allocate the cantonal values to the multiple nodes in the canton, DistIv uses the same weights to disaggregate the cantonal value. Please note that while most cantons have multiple transmission nodes, six cantons have none. We include these cantons in nearby cantons with a transmission node[6].

The modeled distribution system consists of six types of distributed energy technologies, namely PV, biomass wood, biomass manure, CHP, grid-battery, and PV-battery. Grid-batteries charge during low electricity price periods and discharge during high electricity price periods to make inter-temporal market arbitrage. PV-batteries have no direct connection to the grid and in general charge (discharge) when the demand of the PV investor is lower (higher) than his PV generation. Table 2 provides an overview of key parameters for these technologies, using 2018 as the reference year (if not specified otherwise). For the distributed generation technologies we use the data from [36], while for grid-battery and PV-battery, we use the information on the Tesla Powerpack and Powerwall 2 [37]. We assume that PV-batteries have a ratio of 13.5 kWh to 5kW, meaning that a 27kWh battery has a capacity of 10kW. This ratio is based on the Tesla Powerwall 2. PV-batteries are continuously sized, meaning that they can have every size, but they utilize the above mentioned ratio between size (kWh) and capacity (kW). We choose continuous sizing because we consider PV-battery investments on a cantonal level. Furthermore, we do not include any subsidies for batteries. We include four PV categories (i.e., 0-10 kWp, 10-30 kWp, 30-100 kWp, >100 kWp) and limit the maximum installed capacity for each category according to its PV potential, which we calculated based on the Sonnendach data [38]. For PV electricity generation, we use irradiation data from MeteoSwiss [39]. We assume a linear degradation rate of 0.5% per year for PV panels (i.e., each year the annual PV output decreases by 0.5%) [40]. For the investment potential of biomass technologies, we use the data from [36]. We do not limit the investment potential for CHP. In the investment decision for CHP units, we include their carbon emissions and the respective costs due to the CO_2 levy. However, we do not consider the CO_2 levy refund. Furthermore, no investment subsidy is included to offset the investment costs for new CHP. We do not include self-consumption of CHPs and, instead, assume that CHP owners sell the electricity at the wholesale market. We do so, as we assume that larger investors install CHP units and not individual households. For biomass wood, biomass manure and CHP units, we assume a capacity factor of 0.54, 0.78, and 0.28 [36], respectively.

We include decreasing investment and operation costs for PV and batteries until 2050, while all other parameters remain constant. Table 3 presents the assumptions on the development of PV and storage investment and operation costs, presented in percentage of the reference year 2018 based on [36].

To account for the legislative and regulatory framework, we consider investment subsidies, injection tariffs, and tax rebates for PV units. We include investment subsidies for PV units until 2020 based on BFE regulations [41] and assume the subsidy to decrease to 80% of the 2020 level by 2030, and phase-out afterward. The current production subsidy (KEV) is not included for the PV candidate units since KEV is scheduled to phase out in 2022 and it is unlikely any new PV would get accepted into the KEV before then. For the injection tariffs that are set by regional distribution system operator (DSO)s, we use the data

[6] Including data without transmission node into nearby cantons is necessary as input data such as network tariff, injection tariff and investment potentials of different resources are provided on a cantonal level.

Table 2: Parameters for candidate units

Type	Size	Investment cost (EUR/kW)	Variable operation cost (cent/kWh)	Fixed operation cost (EUR/kW/year)	Fuel cost (cent/kWh)	Emissions (eq. g/kWh)	Lifetime (years)	Amortization period (years)
PV	0-10 kWp	2'902	2.73	0	0	0	30	10
PV	10-30 kWp	2'295	2.73	0	0	0	30	10
PV	30-100 kWp	1'570	2.73	0	0	0	30	10
PV	>100 kWp	1'182	1.82	0	0	0	30	10
Biomass wood	50 kWe	6'033	0	675	19.00	35	10	10
Biomass manure	25 kWe	32'909	0	968	8.64	0	15	15
CHP	10 kWe	4'127	3.50	0	7.59	611	20	20
Grid-connected battery	100 kWh	638	0	2.5% of investment cost	0	0	20	20
PV-battery	13.5 kWh	1'156	0	2.5% of investment cost	0	0	15	15

Table 3: Assumptions for future investment and operational costs.

(a) Investment costs

Category	2018	2020	2030	2040	2050
0-10 kWp PV	100%	86%	71%	61%	57%
10-30 kWp PV	100%	87%	71%	57%	44%
30-100 kWp PV	100%	84%	69%	57%	48%
>100 kWp PV	100%	81%	66%	57%	52%
Grid-connected battery	100%	100%	72%	53%	39%
PV battery	100%	100%	72%	53%	39%

(b) Operational costs

Category	2018	2020	2030	2040	2050
0-10 kWp PV	100%	95%	78%	68%	64%
10-30 kWp PV	100%	95%	78%	68%	64%
30-100 kWp PV	100%	95%	78%	68%	64%
>100 kWp PV	100%	95%	78%	68%	64%
Grid-connected battery	100%	100%	72%	53%	39%
PV battery	100%	100%	72%	53%	39%

from ElCom [42] and took an average number for each region. In this work, the regional injection tariffs are assumed to be constant between 2020-2050 due to the uncertainties regarding the development of these tariffs. In the course of the analysis, it became apparent that such an assumption would result in injection tariffs below the wholesale price. This trend is not in line with the planned regulation in Switzerland, so an additional sensitivity simulation was conducted (see Section 4.1.4) where the injection tariff expires in 2025. It can therefore be stated that the PV development in the Baseline scenario is conservative, as is also illustrated by the development in the calculated sensitivity. We also consider a tax rebate of 7.7% on the operation costs and 20% on the net investment costs (excluding the investment subsidy) [43] in all cantons except Luzern and Graubünden due to regional regulations [44]. We assume tax rebates to remain constant until 2050. For the network tariff, we use the consumption group H4 data for 2018 from ElCom (including grid charge and additional fees) [42]. We assume the network tariff to remain constant until 2050.

In addition to the five distributed energy technologies, we also consider DSM. Table 4 presents the values for the total maximum power that can be shifted per hour, and the total energy that can be shifted per day. These numbers represent the socio-technical DSM potential (i.e., acceptance and behavior typically limits the technical potential) and is based on [45, 46], which outline a current socio-economic DSM potential of 0.6-1.15 GW that could increase to 2.5 GW by 2030, particularly due to the uptake of electric vehicles and heat pumps (more details about the DSM limits and costs can be found in the Input Data report).

Table 4: Overview of DSM Potential

DSM Potential	2020	2030	2040	2050
Total maximum power that can be shifted per hour [GW]	0.7	0.9	1	1
Total energy shifted per day [GWh]	2.25	2.75	3	3

3 Scenarios

We analyze three scenarios (**Baseline**, **Nuclear 60**, **High Flexibility**) of the future Swiss power system. Each scenario simulation consists of four years (2020, 2030, 2040, and 2050), which we refer to as scenario-years. Table 5 provides an overview of the key differences between the scenarios. It is important to note that we do not model a Net Zero future for any of the simulated countries and scenarios. For the surrounding countries (AT, DE, FR, IT), [24] is used as the main source of capacity development projections. These projections do include significant shares of gas power plants. In Switzerland, we also introduce open/combined cycle gas turbines (without carbon capture) as candidate units.

Table 5: Overview of scenarios and their key differences

	Nuclear Capacity [MW]				**DSM Potential (maximum power shifted per hour [GW] / maximum energy shifted per day [GWh])**				**BSS Cost Development [% change to starting value in 2018] (Starting value: 1'156 EUR/kWh)**			
Scenario / Year	2020	2030	2040	2050	2020	2030	2040	2050	2020	2030	2040	2050
Baseline	2645	1220	0	0	0.7 / 2.25	0.9 / 2.75	1 / 3	1 / 3	100%	72%	53%	39%
Nuclear 60	3010	2645	1220	0	0.7 / 2.25	0.9 / 2.75	1 / 3	1 / 3	100%	72%	53%	39%
High Flexibility	2645	1220	0	0	1.4 / 4.5	1.8 / 5.5	2 / 6	2 / 6	100%	36%	26.5%	19.5%

The **Baseline** scenario includes the projected development of input parameters as described in Section 2.5, for example, the lifetime of 50 years for nuclear power plants. It also represents the status quo of the Swiss legislative and regulatory framework, such as the financial subsidies for PV systems. This scenario is set as the base case based on the discussions with BFE.

The **Nuclear-60** scenario reflects the uncertainty about the nuclear power phase-out. It builds upon the Baseline scenario but assumes that nuclear power plants are phased-out after a lifetime of 60 years each, instead of the 50 years in the Baseline scenario. The lifetime of the plants is a crucial assumption as it defines the pace of the nuclear exit: While the update of the Swiss energy law in 2018 forbids the construction of new nuclear power plants and fundamental modifications to existing nuclear power plants, existing nuclear power plants may continue to operate as long as they fulfill the conditions for safe operation, which is decided by the Swiss Federal Nuclear Safety Inspectorate (ENSI), an independent federal authority. The lifetime of each individual power plant is, therefore uncertain and is difficult to foresee. It is important to highlight that there are no legal limits on the operating life of reactors besides the safety regulation. Table 6 compares the year of the phase-out of the nuclear power plants in Switzerland when assuming a lifetime of 60 years, compared to the 50 years in the Baseline scenario.

Table 6: Overview nuclear power phase out under 50 and 60 years of lifetime

Nuclear power plant/reactor	**Capacity**	**Operation since**	**Phase-out in year (runtime 50 years)**	**Phase-out in year (runtime 60 years)**
Beznau 1	365	1969	2019	2029
Beznau 2	365	1972	2022	2032
Mühleberg (KKM)	355	1972	-	-
Gösgen (KKG)	1060	1979	2029	2039
Leibstadt (KKL)	1220	1984	2034	2044

The **High-Flexibility** scenario reflects the discussion on the impact and value of an increased supply of distributed flexibility in the power system. The scenario builds upon the Baseline scenario and assumes 50% lower battery costs and 100% higher demand-side management potential for 2030-2050, compared to the Baseline scenario, while leaving the starting values for 2020 unaffected (as shown in Table 5). Thus, we only adjust the cost projections of battery storage and the DSM potential, therefore accounting for the uncertainties in the development of both parameters. For battery storage, a 2018 report by the European Commission outlines observed and reported values for battery pack prices, which range from below 200 €/kWh to above 1400 €/kWh [4]. The report also highlights that while most studies foresee strong technology learning, cost projections for future years vary substantially, for example, ranging from below 50 €/kWh to above 250 €/kWh in 2040. The main driver of battery costs development but also its uncertainty is the electrification of the transport sector and the projected electric vehicle uptake. Similarly, for DSM, calculating its current and future potential for Switzerland is challenging. Results for today's socio-technical DSM potential (i.e., acceptance and behavior typically limits the technical potential) range between 0.6 GW [45] and 1.15 GW [46] and could go up to 2.5 GW by 2030 [46]. Key drivers for increasing DSM potential are the projected uptake of electric vehicles and heat pumps. Again, the drivers of uncertainties are the diffusion of electric vehicles but also the acceptance of their owners to participate in DSM programs. We defined the higher values for DSM potential in the High-Flexibility scenario to reflect the increasing DSM potential suggested in literature [45, 46].

4 Results

This section presents our results for the development of the Swiss electricity system under the three scenarios until 2050. It presents the annual installed capacities and generated electricity in the scenarios between 2015 and 2050 (Section 4.1) and outlines the need (Section 4.2) and supply (Section 4.3) of flexibility. Finally, it addresses the social and environmental impacts (Section 4.4). It is important to note that net-zero emissions targets (for Switzerland or the surrounding countries currently modeled) are not included in any of the simulated scenarios.

4.1 The future Swiss electricity system

This section presents the development of the Swiss electricity system until 2050 for each of the three scenarios. It outlines the installed capacities (Section 4.1.1) and the electricity generation (Section 4.1.2) and compares electricity generation by renewables with the RES targets (Section 4.1.3). Additional sensitivity analyses illustrate the impact of uncertainties on PV investments (Section 4.1.4) and on wind investments (Section 4.1.5).

Key takeaways:

- In all scenarios, PV investment replaces nuclear capacity to a large extent[7], with some additional investments in biomass and PV-batteries (in the High-Flexibility scenario, PV-battery investment is substantial), but no investment in grid-batteries and wind power. However, between 2030 and 2040, the phase-out of investment subsidies makes investments in PV less attractive, resulting in stagnating PV installations. Decreasing PV prices and PV-batteries that improve the economic viability of PV units spur PV installations, resulting in 25.4-31.1 GW PV installations by 2050.
- By 2050, PV is responsible for the largest share (i.e., 32.6-35.5%) of electricity consumption, followed by hydro dam (26.0-28.3%) and hydro RoR (15.9-17.4%). Despite such uptake of PV, it cannot substitute nuclear phase-out fully and, consequently, Switzerland becomes a net importer in 2030 (in the Nuclear-60 scenario in 2040) and remains one until 2050. As nuclear phase-out progresses, imports become a larger contributor, supplying up to 5.7% of the demand in 2050. Critical, however, is the time between 2030-2040, when the PV capacity investments stagnate, resulting in substantially higher net imports of up to 16.5% of the annual demand.
- RES targets are achieved in all scenarios and years. The most critical year is 2040 due to stagnating PV investment. To account for the pronounced uncertainties our results are subject to, we conduct sensitivity analyses related to both PV (i.e., on PV costs, injection tariffs, and wholesale market prices) and wind (i.e., reduced future investment costs).

4.1.1 Capacities and investments

Figure 4 shows the installed generation capacity per technology type (existing and new) between 2015 and 2050 for the Baseline scenario, along with the Nuclear-60 and the High-Flexibility scenarios.

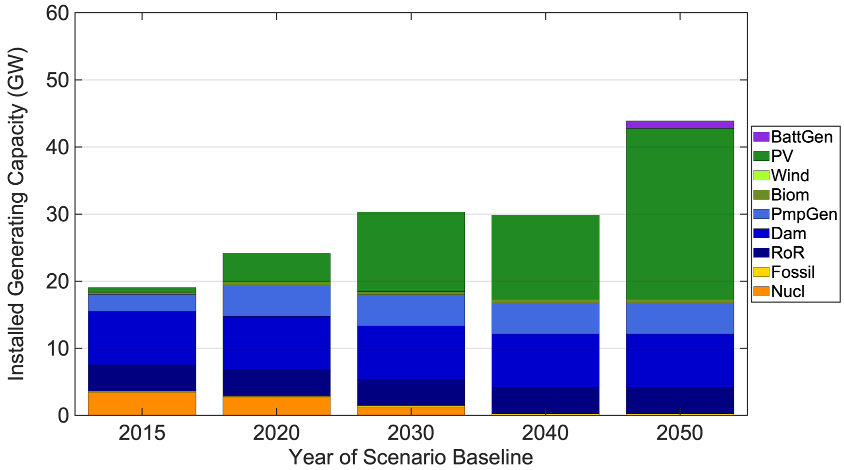
In the Baseline scenario (Figure 4a), the Swiss nuclear fleet is phased-out by 2040, after 50 years of lifetime. The nuclear generation is replaced by four technologies: PV, PV-battery, biomass, and hydro pump storage. The PV total installed capacity achieves 25.4 GW by 2050. PV installations increase

[7] These PV investments are based on a number of assumptions, including a homogeneous investor population. To better understand these assumption as well as their context and limitation please see the discussions in the DistIv module validation (Validation and Calibration of Modules report) and in the sensitivity analysis of PV investments (Section 4.1.4) for more details.

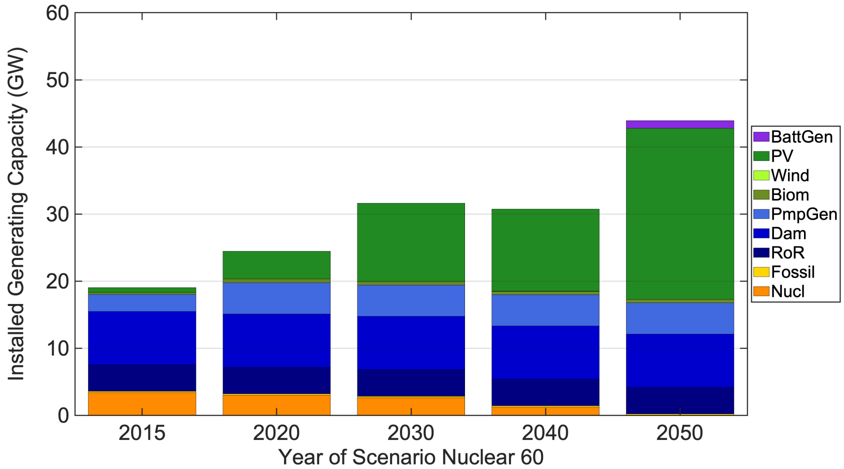
substantially between 2020 and 2030 (by 7.6 GW) but then stagnate until 2040 due to the phase-out of financial subsidies. However, with the decrease in PV costs and the increase in electricity prices, the PV installations rise again significantly between 2040 and 2050 (by 12.9 GW). PV-batteries of 1.1 GW are built in 2050 while no such capacities are built in the prior years. However, no grid-based batteries are built by 2050 as the diurnal wholesale electricity price spread is too small for profits from arbitrage operations. Furthermore, 240 MW of new biomass capacity (waste incinerators) are built in 2020, which include all of the potential units allowed. The pump storage capacity doubles between the 2015 reference year and 2020 scenario-year. These new capacities, which include Limmern (2018), Nant de Drance (2019), and Veytaux (expanded in 2018), are integrated into the electrical grid before 2020, and are not a result of the scenarios. The results show no increase in wind capacity by 2050, although we consider a technical potential from wind capacities of 1.9 GW in the simulations.

In the Nuclear-60 scenario (Figure 4b), the Swiss nuclear fleet is phased-out by 2050, after 60 years of lifetime. The results show that the speed of the nuclear phase-out has only a minor impact on the number of PV installations in 2030 (83 MW less compared to the Baseline) and in 2040 (238 MW less compared to the Baseline). With slightly higher PV investments in 2050 (357 MW more compared to the Baseline), the total installed PV capacity by 2050 of 25.5 GW is almost identical to the Baseline scenario. Also, the decisions on the other capacities such as batteries (1.1 GW), biomass (240 MW), pumped hydro (all before 2020), and wind (none) are the same as in the Baseline scenario.

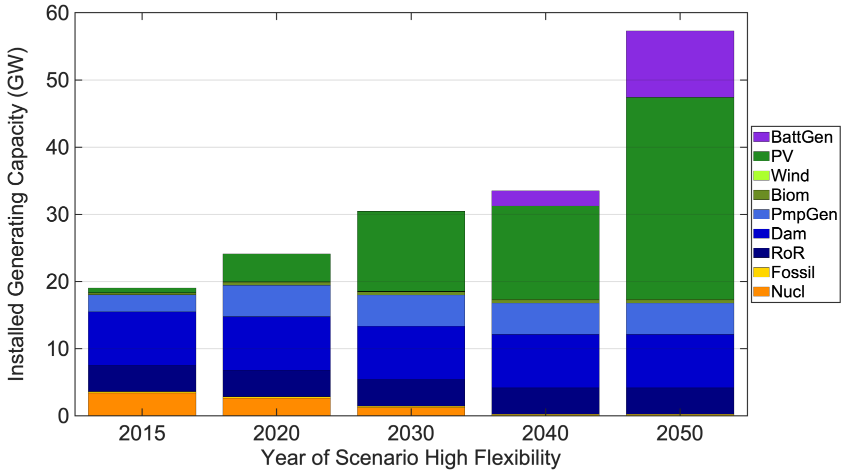
In the High-Flexibility scenario (Figure 4c), we observe a strong increase in PV-battery installations. PV-batteries are already installed in 2040, achieving 9.9 GW by 2050. Compared to the Baseline scenario, PV-battery installations thus start 10 years earlier and achieve an 800% higher capacity by 2050. The stronger battery investments also enable higher PV investments in 2040 and 2050. PV-batteries increase the self-consumption of PV electricity and thereby the economic viability of PV systems. The High-Flexibility scenario results in 30.1 GW of PV installations by 2050, which is 18.3% more than in the Baseline scenario.



(a) Baseline



(b) Nuclear 60



(c) High Flexibility

Figure 4: Comparison of the installed capacity by technology type (existing and new) between 2015 and 2050 for the three scenarios.

4.1.2 Annual production by technology

Figure 5 shows the annual electricity generation and loads between 2015 and 2050 for the Baseline scenario along with the Nuclear-60 and the High-Flexibility scenario.

In the Baseline scenario (Figure 5a), the net load decreases over time, even though the electricity demand increases from 62.6 TWh in 2015 (reference year), to 65.5 TWh in the 2050 scenario-year[8].The decrease in the net load occurs due to the increasing PV electricity generation and results in reduced electricity supply by non-intermittent power plants. However, despite the new PV electricity, Switzerland becomes a net importer starting in 2030, mainly due to the nuclear exit. The increase in annual net imports is particularly pronounced in 2040 (i.e., net-imports of 11.7 TWh) when PV installations stagnate, and the remaining nuclear power plants are phased-out. In 2050, PV generation increases again and reduces net imports to 4.2 TWh. Besides net imports, also the absolute values for both imports and exports increase substantially in 2040 and 2050. One of the reasons for the increased electricity trade is that we define higher NTCs in the simulation of these years[9]. The generation from RoR hydro decreases in 2050 due to curtailments caused by transmission grid congestion and generation surplus. Our model curtails the most expensive units first, and as we assume that the operation of Swiss RoR is more expensive than wind or PV, the model curtails Swiss RoR first. Also in 2050, the 1.1 GW of PV-batteries shift 0.84-0.94 TWh over the year. Furthermore, the use of pumped-hydro (generation and load) increases in 2020 compared to 2015 because of the new stations that are built between 2015 and 2020. Similarly, the biomass generation increases in 2020 because of the investments made in 2020. Biomass production also increases in 2040 because already built biomass plants switch operation from providing reserves to providing energy. Finally, wind generation remains at the low 2015 level, because no new capacities are installed. By 2050, PV is responsible for the largest share (i.e., 32.6-35.5%) of electricity consumption, followed by hydro dam (26.0-28.3%) and hydro RoR (15.9-17.4%).

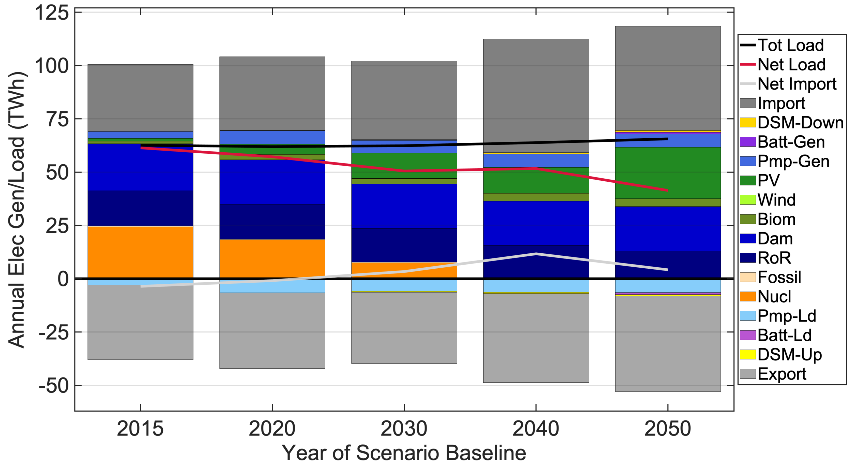
In the Nuclear-60 scenario (Figure 5b), due to their longer lifetime, nuclear power plants produce an additional 10.2 TWh and 7.9 TWh in 2030 and 2040, respectively, compared to the Baseline scenario. In 2030, the higher nuclear production but similar PV production (0.68% less compared to Baseline) allows Switzerland to remain a net exporter (i.e., 6.2 TWh, the highest level of net exports of any scenario and scenario-year).

In the High-Flexibility scenario (Figure 5c), net imports are very similar in 2020 and 2030 compared to the Baseline scenario, slightly lower in 2040 (10.4 TWh compared to 11.7 TWh), and notably lower in 2050 (0.5 TWh instead of 4.2 TWh). The main driver of these differences is the higher number of PV installations in 2040 and 2050 in the High-Flexibility scenario compared to the Baseline scenario. Additional PV investments produce notably more electricity in 2040 (13.5 TWh instead 12 TWh) and 2050 (28.4 TWh instead 24.1 TWh) than in the Baseline. Also in 2050, production/consumption from PV-batteries and DSM becomes more significant (6.3/6.9 TWh and 1.6/1.6 TWh) than in the Baseline. Furthermore, PV-batteries produce and consume similar amounts of electricity as pumped-hydro storage but have twice the installed capacity. In 2050, the 9.9 GW of PV-batteries charge 7 TWh and discharge 6.3 TWh [10], corresponding to a capacity factor of around 15.3% (compared to a capacity factor of 28.7% for pumped hydro in 2050). We explain the low capacity factor of PV-batteries as follows: First, their power-to-energy ratio (i.e., 5 kW/13.5 kWh) is much higher than of a typical hydro storage plant, which means it takes less time for the PV-batteries to be charged fully. Second, the PV-batteries are only charged with PV electricity. Thus, their charging/discharging behavior depends on the amount of generation from the PV units. PV output has a strong diurnal and seasonal pattern. For example, the PV-batteries operate less in winter when most of the PV generation is self-consumed. Approximately 2/3 of the PV-battery charging/discharging occurs within a period of 6 months, namely May to October.

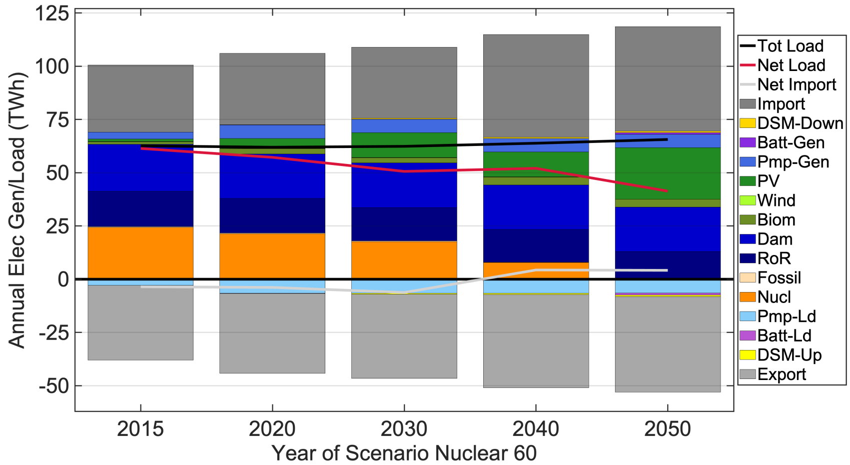
[8]The total demand is an exogenous input. However, these values are the starting points that the macroeconomic model (GemEl) adjusts, which in this case do not change sufficiently to be considered further.

[9]More details on the NTC values are given in the "Input Data and System Setup" report.

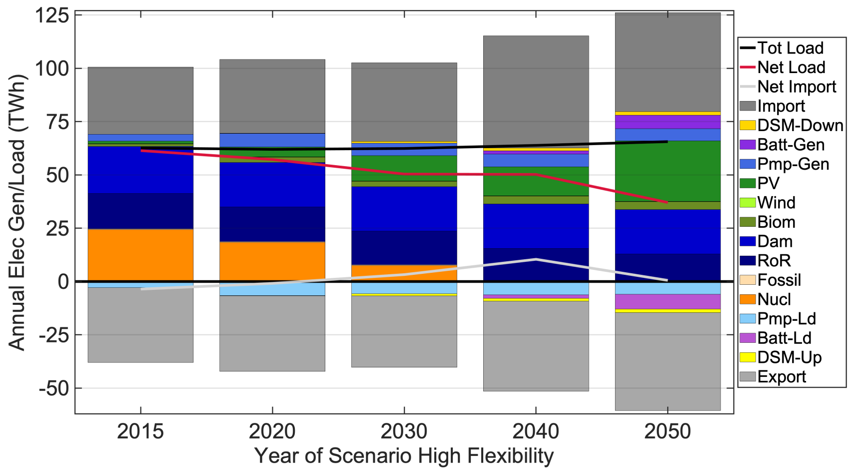
[10]Charging energy is higher than discharging energy due to the battery roundtrip efficiency of 90%.



(a) Baseline



(b) Nuclear 60



(c) High Flexibility

Figure 5: Comparison of the annual generation by technology type between 2015 and 2050 for the three scenarios.

4.1.3 Renewable target versus annual production

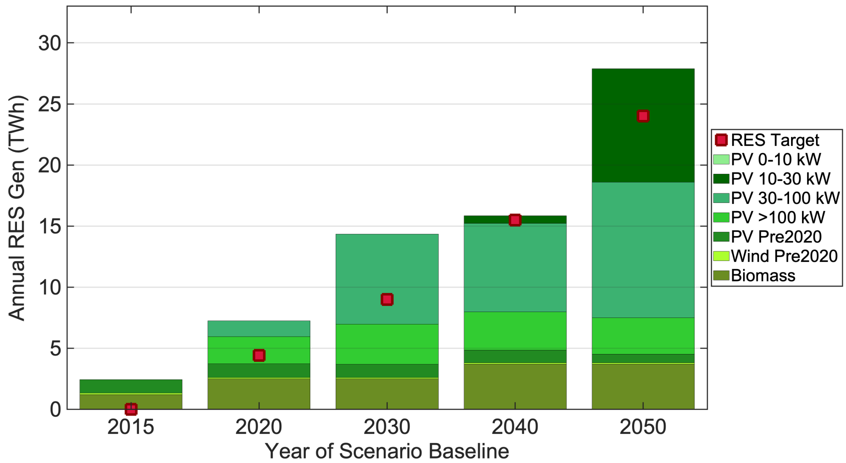
Figure 6 shows the annual electricity generation by non-hydro renewables between 2015 and 2050 for all scenarios and compares it with the annual RES targets. In all scenarios and scenario-years, RES generation exceeds the RES targets, except in 2040 in the Nuclear-60 scenario, in which the RES target is missed by 0.1%. Please note that the assumptions we have made heavily affect our results from the scenario simulations. Therefore, we do not claim that the RES targets are achieved, given the modeled regulatory and legislative framework. However, the results can indicate how the differences in the scenario-inputs (i.e., lifetime of nuclear power plants, investment cost of battery storage, DSM potential) affect RES capacity installations and electricity generation. Also, we conducted sensitivity analyses to understand better how our assumptions on different input parameters (e.g., amortization period) affect the investments in the distributed PV (Section 4.1.4).

The Baseline scenario (Figure 6a) achieves the RES targets in all years, mainly due to investments in PV capacities. In 2040, however, RES generation only barely reaches the target because of the stagnant PV installations in that year. Installed PV capacities differ substantially between PV sizes. While in 2020 and 2030 only larger-sized PV (i.e., PV > 100 kWp, PV 30-100 kWp) units are installed, investment shifts to smaller-sized PV (i.e., PV 10-30 kWp, PV < 10 kWp) in 2040 and 2050. In our model, larger-sized PV units get installed first because their investment costs are lower compared to smaller-sized PV and we do not account for idealistic motivations, i.e., non-economical reasons, to install PV. However, the PV potential per size limits their installations in later years. In 2040 and 2050, with decreasing prices, smaller-sized PV becomes cost-effective in cantons with high solar irradiation. Please note that, in our results, PV with a capacity of 0-10 kWp are not installed by 2050, which is a consequence of the DistIv validation.[11]

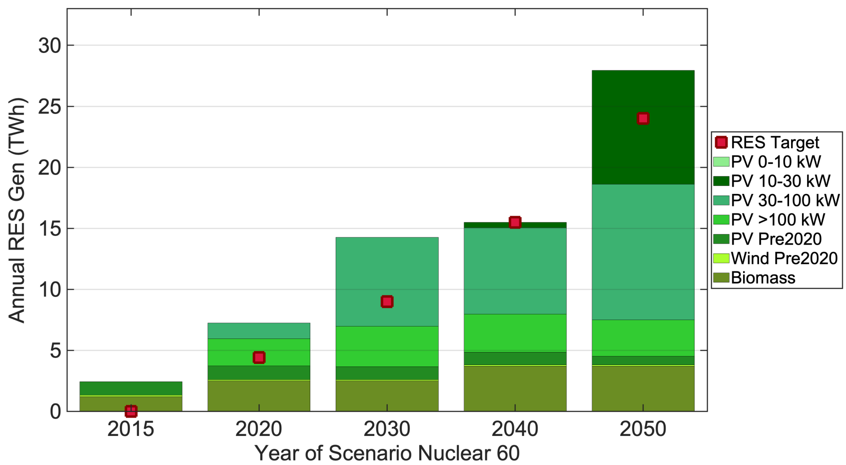
In the Nuclear-60 scenario (Figure 6b) the RES targets are achieved in 2020, 2030, and 2050 but not in 2040. Compared to the Baseline scenario, in 2040, 300 MW less PV capacity is built. Consequently, the RES generation misses the desired RES target by 0.1%. The phase-out of the PV investment subsidy in 2030 and the 60-year lifetime of nuclear power plants, therefore, jeopardizes the achievement of the RES target.

In the High-Flexibility scenario (Figure 6c), the RES targets are all achieved. This scenario also results in the highest RES electricity generation by 2050, amounting to over 32 TWh in 2050.

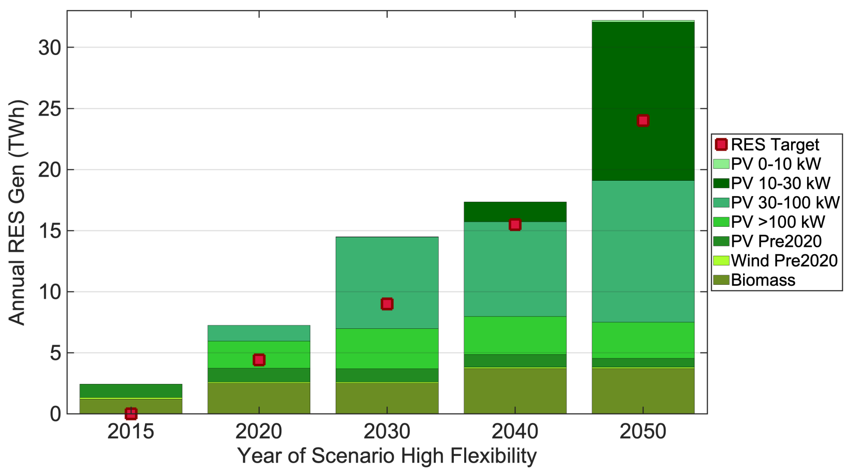
[11] The Calibration and Validation report explains the DistIv validation process in more detail.



(a) Baseline



(b) Nuclear 60



(c) High Flexibility

Figure 6: Comparison of the annual generation by renewables between 2015 and 2050 along with the desired renewable production target for the three scenarios.

4.1.4 Sensitivity analysis of PV investments

As detailed in the DistIv module report, the annual revenue of PV investments consists of savings from self-consumed electricity, profits from injecting excess electricity back to the grid, annualized investment subsidies and tax rebates minus the annualized investment cost and the yearly operating cost. The profitability of PV investments is subject to uncertainties as the future development of PV costs, injection tariffs, wholesale market prices, etc. are unknown. Additionally, in our model, financial parameters such as weighted average cost of capital (WACC) and amortization periods are simplified as a constant value for all modeled PV categories, which is likely not the case in reality[12].

To investigate how the profitability of PV and consequently the investment decisions are affected by our assumptions, in this section, we show the results of conducting a set of one-at-a-time sensitivity analyses of some main financial parameters such as the amortization period, projections of PV costs and PV injection tariffs, while keeping the remaining financial parameters equal to the Baseline scenario value. In addition, we also study the effects of WACC and results are shown in Appendix B. Figure 7 shows the cumulative installed PV capacity for a **5-year**, **10-year** (i.e., Baseline scenario), and **15-year** amortization period, respectively. It highlights that a longer amortization period results in a higher installed capacity. Assuming the yearly revenue is unchanged, a longer amortization period reduces the equivalent annualized capital cost and makes the investment more affordable and more attractive. Furthermore, the sensitivity of PV investments to the length of the amortization period becomes stronger as the amortization period gets shorter, which is a result of the non-linear relationship between the amortization period and the annuity factor [13].

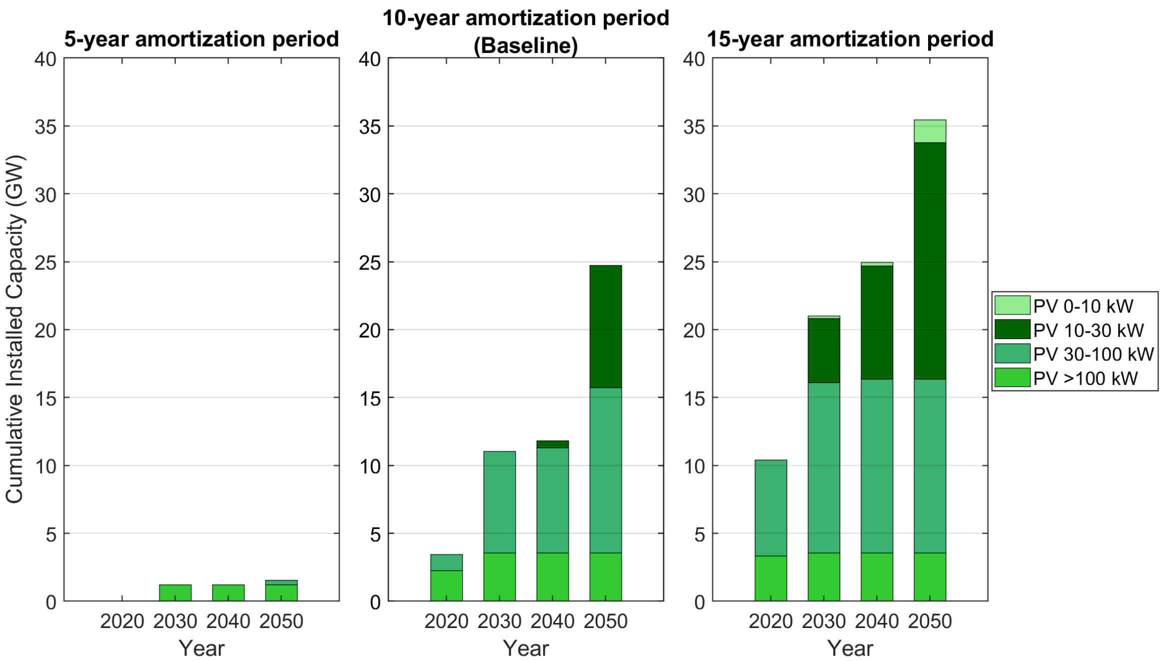


Figure 7: Effects of PV amortization period on the cumulative PV investment capacity.

[12]In fact, different potential investors, from individual homeowners to larger industrial operators, might have different needs regarding their desired payback period as well as different considerations about financing an investment in PV including the amount of debt they take on and the interest rate set by their lender. Additionally, the constant assumptions ignore that some investors have non-economic desires, such as early adopters and innovators who might be driven by environmental issues versus laggards and late majority who might have a higher risk aversion.

[13]The annuity factor is computed by $\frac{r}{1-1/(1+r)^{l}}$, where r is the weighted average cost of capital and l is the amortization period of the candidate unit.

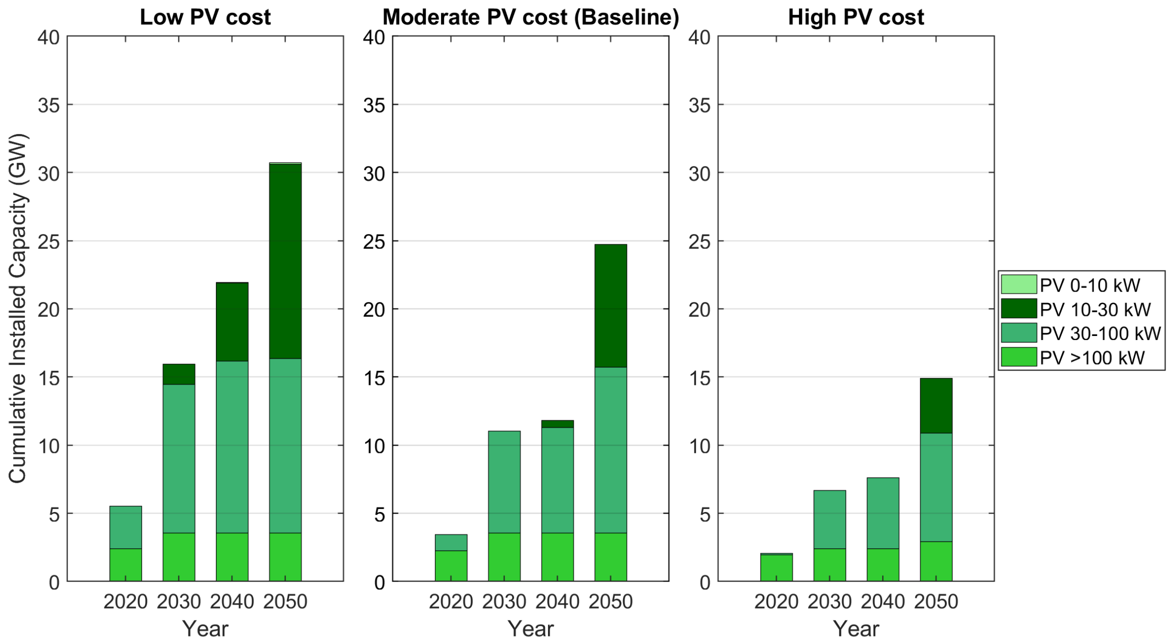


Figure 8: Effects of PV cost projections on the cumulative PV investment capacity.

Figure 8 compares the installed PV capacity for a **low**, **moderate** (i.e., Baseline scenario), and **high** PV cost scenario. The annual decrease in the investment costs per kW of PV in the low and high scenario is in average 9% higher and 9% lower, respectively, than the yearly decrease in the moderate scenario relative to the 2018 reference cost while the operational cost differences between scenarios are minor. Details of the cost projections for these three scenarios based on [36] can be found in Appendix C. The results in Figure 8 illustrate that slightly different projections for the future development of PV prices have a substantial impact on installed PV capacities due to the cumulative effect. Even though the difference between the low and high PV cost scenario is in average only 18% of the reference 2018 cost, with the decreasing PV cost this difference accounts for a growing portion of the future cost and finally the resulting PV investment capacity by 2050 under the high PV cost scenario is less than half of the capacity under the low PV cost scenario.

Figure 9 shows the impacts of the injection tariff on the resulting PV investments for two scenarios: (i) in the **constant** injection tariff scenario the injection tariff remains constant until 2050 at the 2018 level (i.e., Baseline scenario); (ii) in the **2025-expired** injection tariff scenario the injection tariff expires by 2025, after which excess PV electricity is sold at the wholesale market price. The results show that the replacement of the injection tariff by the wholesale market price in 2025 yields more PV investments already in 2030. While not immediately intuitive, this result is mostly due to increasing future wholesale prices that are influenced by future fuel and CO_2 prices[14]. As shown in Table 7, in 2030, the average wholesale electricity price is already higher than the average injection tariff. And although the PV-generation-weighted wholesale electricity price, calculated using the average PV capacity factor, is still a bit lower than the average injection tariff, replacement by the wholesale market price could encourage investments in some regions and possibly higher total PV investments. While the impact on cumulative PV installations is minor in 2030, it is substantial by 2040 (+4.5 GW) and by 2050 (+3.5 GW). To understand the shift from the constant injection tariff to replacing it with the wholesale prices, we investigate the development of the injection tariff and wholesale market prices for 2030-2050 (see Table 7).

[14] The average wholesale prices shown are a result of the assumed projection of fuel and CO_2 prices, the assumed generation capacities in the surrounding countries, and the assumed limits on intra-market trading. While the values in 2050 seem high, they are inline with those reported in the AFEM project, which utilized similar assumptions.

The average wholesale electricity price increases from year-to-year (mainly due to the increasing CO2 and fuel costs) and clearly surpasses the injection tariff in 2040. However, since PV generates electricity only during the daytime when prices tend to be low, the average wholesale price overestimates the value of any excess PV energy injected during these hours. Therefore we instead compare the injection tariff with a PV-generation-weighted price[15] to account for the diurnal electricity generation pattern of PV units. It shows a lower value than the average injection tariff in 2030[16], but higher values for 2040 and 2050. Interestingly, the PV-generation-weighted price in 2050 is lower than that of 2040 due to the increasing PV penetration (i.e., greater PV production in 2050 depresses the wholesale prices during the hours PV tend to generate compared to 2040, even though fuel and CO_2 prices are higher in 2050), which also explains the lower cumulative difference between the two scenarios.

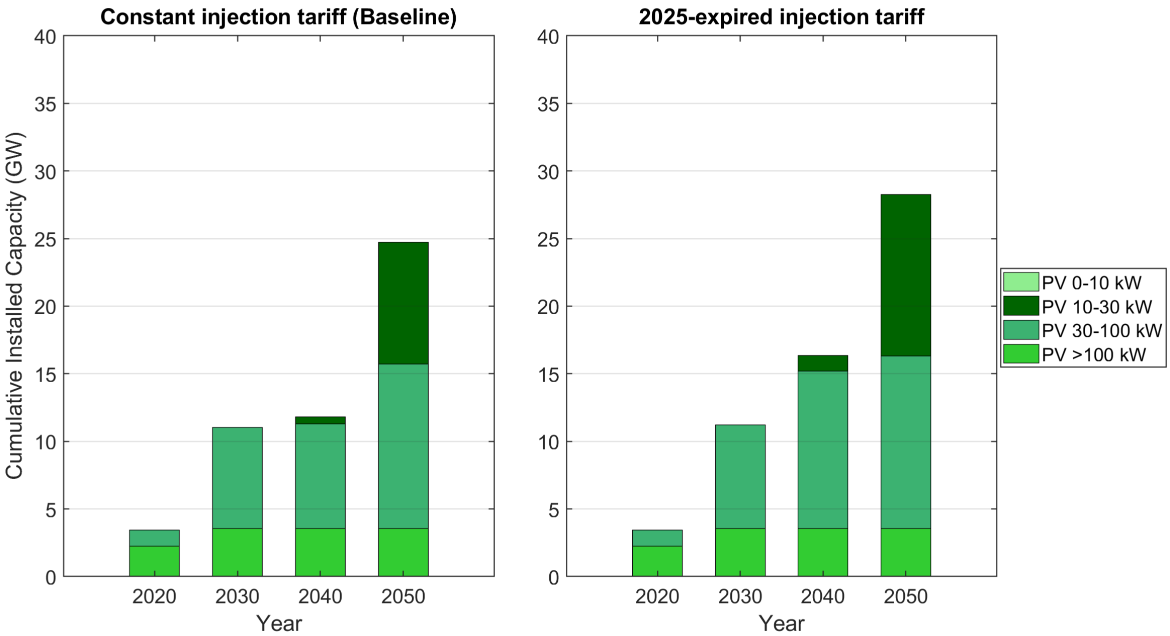


Figure 9: Effects of PV injection tariffs on the cumulative PV investment capacity.

Table 7: Injection tariff and (generation-weighted) wholesale electricity prices for years 2030-2050.

	2030	**2040**	**2050**
Average Injection tariff on 2018 level [cent/kWh]	8.1	8.1	8.1
Average wholesale electricity price [cent/kWh]	8.3	11.0	12.0
PV-generation-weighted wholesale electricity price [cent/kWh]	7.6	9.8	9.5

[15] It is defined as $\frac{\sum_t pr_t^{\mathrm{DA}} p_{p,t}^{\mathrm{cf}}}{\sum_t P_{p,t}^{\mathrm{cf}}}$, where pr_t^{DA} and $p_{p,t}^{\mathrm{cf}}$ are the hourly wholesale price and the hourly capacity factor of PV.

[16] Note that values shown in Table 7 are averaged across all regions and higher injection tariff does not necessarily mean higher PV installations in total.

4.1.5 Sensitivity analysis of wind investments

The preceding results were obtained assuming a constant investment cost for new wind capacities over the 2020-2050 time horizon. This assumption and the cost assigned are based on Swiss-specific studies [25, 26] that both highlight the uncertainty of future cost projections for wind projects in Switzerland. To better understand the impact that the trend of future wind investment costs could have on the results, an additional sensitivity scenario is defined that sets future cost reductions based on additional data in the same Swiss studies [25, 26].

Table 8 lists the wind candidate investment costs selected for each of the 2020-2050 scenario-years for this sensitivity scenario, named Low Wind Cost. Values are provided in (CHF/kW), which is consistent with the referenced reports, as well as converted into (kEUR/MW/a), which is how the values are implemented in Nexus-e. The values for 2020 and 2030 were based on the data provided directly in [25] for both 2020 and 2035[17]. Using the 2020 and 2035 references, a constant percent reduction per year is calculated and applied to estimate the appropriate 2030 wind investment cost (i.e., a reduction of 2.42 % per year is assumed between 2020-2035). However, this study does not provide any specific wind cost values beyond 2035 and instead indicates that wind cost reductions beyond 2035 are "only marginal" and should be "in line with international development". Therefore, the values selected for 2040 and 2050 use the selected 2035 value along with the cost reduction trends for the years 2035-2050 provided in their earlier report [26]. From this earlier study, a constant percent reduction per year is calculated and applied to estimate the appropriate 2040 and 2050 wind investment costs (i.e., a reduction of 0.90 % per year is assumed between 2035-2050). The results presented below for this sensitivity are consistent with the Baseline scenario in all aspects except that they use the adjusted wind investment costs.

Table 8: The assumed wind investment costs (shown in both CHF/kW and kEUR/MW/a) for the 2020-2050 scenario-years in this sensitivity scenario reduce over time compared to the Baseline scenario.

Scenario [unit]	Investment cost				
	2020	**2030**	**2035***	**2040**	**2050**
Baseline [CHF/kW]	2500	2500	-	2500	2500
Low Wind Cost [CHF/kW]	2500	1895	1730	1654	1512
Low Wind Cost [kEUR/MW/a]	182.4	142.7	126.2	120.7	110.3

*This year is not simulated and is only used as a reference for calculating the Low Wind Cost scenario values in 2030, 2040, and 2050

Figure 10 shows the installed generation capacity per technology type (existing and new) between 2015 and 2050 for the Low Wind Cost scenario. Comparing these capacities with that of the Baseline scenario (see Figure 4a), the lower wind investment costs result in a positive economic benefit and therefore investments in wind capacity in 2040. In fact, all included candidate wind capacity is built in 2040, increasing the existing 75 MW of wind capacity in Switzerland to just over 2 GW. While it is notable that all wind capacity is built, this result is partly explained by the assumption of identical investment and operational costs for all wind candidates in a given year. So, when any wind candidate provides a positive economic benefit toward the total system production costs, it is likely that most or all wind candidates provide a similar benefit[18]. The expansion of wind capacity has very little impact on the PV investment decisions in 2040 or 2050.

[17] The report [25] provides values for their assumed 2020 and 2035 levelized cost of electricity (LCOE) but does not provide any break down of these costs. The 2020 LCOE from [25] is in line with the LCOE range given for 2020 within their earlier report [26]; this previous report also does provide a value for the associated investment cost portion equal to 2500 CHF/kW. The 2035 LCOE from [25] is consistent with the LCOE referenced from suisseéole within [25]; suisseéole also does provide a value for the associated investment cost portion equal to 1730 CHF/kW.

[18] Differences in the production profiles and possible required location-dependent curtailments can cause some wind candidates to have better economic benefits than others.

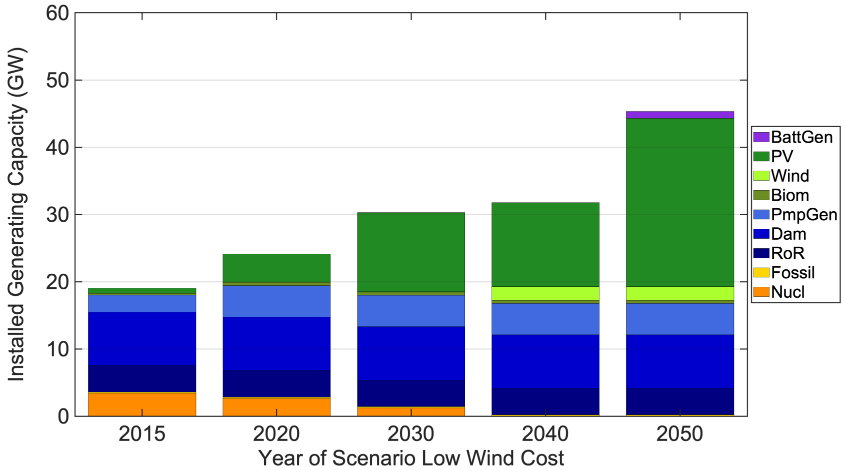


Figure 10: Comparison of the installed capacity by technology type (existing and new) between 2015 and 2050 for the Low Wind Cost sensitivity scenario.

Figure 11 shows the annual electricity generation and loads between 2015 and 2050 for the Low Wind Cost scenario. Comparing these annual generation levels with that of the Baseline scenario (see Figure 5a), the added wind capacity in 2040 makes up a more noticeable portion of the Swiss production portfolio. While still a small portion (i.e., just under 4.0 TWh per year, which is around 5 % of the annual Swiss demand), the wind production contributes the same amount as biomass and a bit over half as much as pumped hydro. This increase in domestic production impacts the imports and exports in 2040 and 2050. Imports reduce by around 2.0 TWh per year while exports increase by around 1.5 TWh per year, leading to a downward shift in the annual net imports by 3.7 TWh in 2040 and by 3.0 TWh in 2050. Looking deeper into the changes reveals that the wind production is mostly offsetting generation from GasCC units in Germany, Italy, and France. However, the amount of production offset from these GasCC units is very small compared to the annual production from GasCC in each country (e.g., a 1.23 TWh reduction of GasCC in Germany compared to the annual production of over 164 TWh in the Baseline scenario).

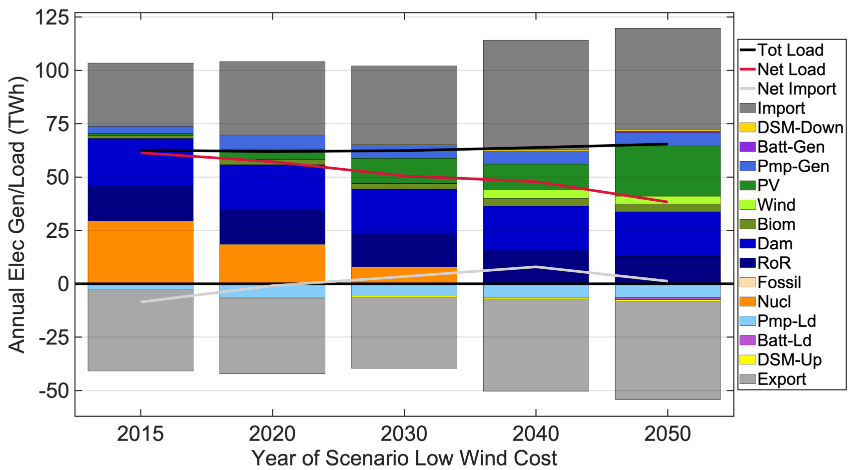


Figure 11: Comparison of the annual generation by technology type (existing and new) between 2015 and 2050 for the Low Wind Cost sensitivity scenario.

Figure 12 shows the annual electricity generation by non-hydro renewables between 2015 and 2050 for the Low Wind Cost scenario and compares it with the annual RES targets. Comparing these RES production levels with that of the Baseline scenario (see Figure 6a), the additional 3.8 TWh of wind production in 2040 more comfortably satisfies the 2040 RES target and only makes a minor reduction in the PV generation in 2050 (i.e., 0.49 TWh less). The additional wind generation is still only about 11.5 % of the total RES production in 2050, which is still mostly supplied by PV (i.e., 76.5 % of the total RES production).

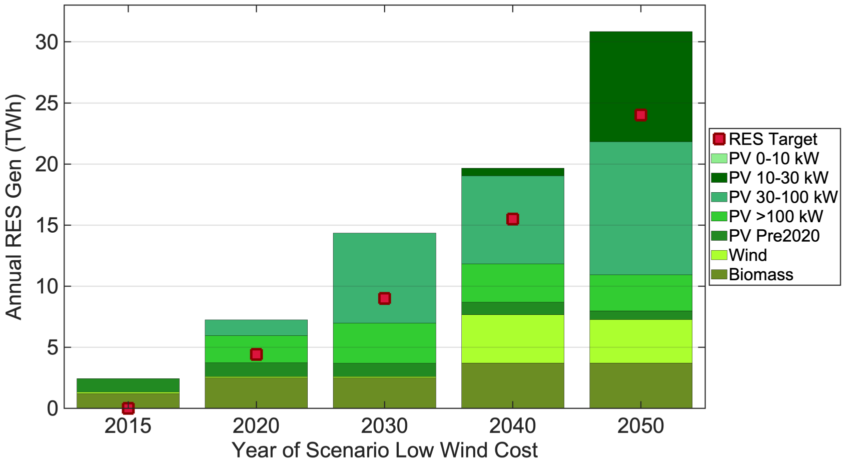


Figure 12: Comparison of the annual generation by renewables between 2015 and 2050 along with the desired renewable production target for the Low Wind Cost sensitivity scenario.

4.2 The system's need for flexibility

This section describes the scenario input data and investment results from the Nexus-e platform, that together provide the basis for the needs of flexibility across the timescales previously introduced (seasonal, daily, hourly, and sub-hourly). The following subsections provide details on how flexibility needs develop for (i) seasonal patterns of generation and demand (Section 4.2.1), (ii) daily and hourly fluctuations in the net load (Section 4.2.2), and (iii) sub-hourly services for system stability and frequency control (Section 4.2.3).

Key takeaways:

- The seasonality of the net load increases in all future years and is more pronounced in 2050 as the PV penetration level is higher. This trend indicates a need for greater seasonal flexibility that could impact the operation of hydro storage power plants or other generators as well as the pattern of imports and exports.
- The increasingly dynamic pattern of the net load on an hourly and daily basis emphasizes the need for fast ramping flexible capacities such as hydro dams along with storage systems and load shifting units like pumped hydro, battery storage system (BSS), or DSM. Furthermore, in future years, more frequent curtailments of non-dispatchable units should be utilized for flexibility.
- Tertiary reserve requirements increase from year-to-year as new PV investments are added. Overall, the increases in tertiary requirements are noticeable, adding around 200 MW to both upward and downward reserves in 2050 compared to the base requirement of 227 MW and 442 MW for upward and downward reserve, respectively.
- The increased share of non-dispatchable units in the system requires more flexibility to manage short-term system stability. A lack of flexibility in the power system will have a negative effect on the system security and, thus, will contribute to the risk of systemic failures.

4.2.1 Seasonal

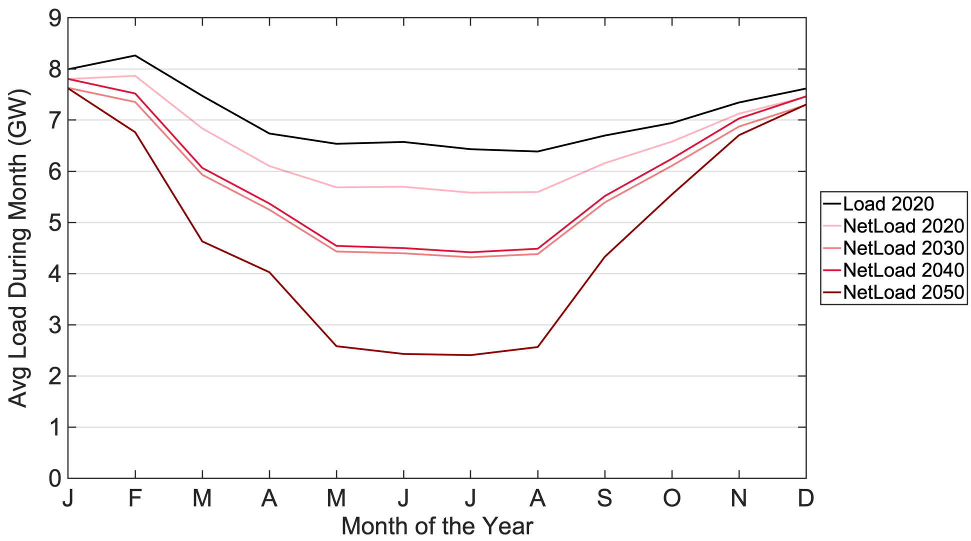
Figure 13 shows the average hourly total load per month for 2020 and the average hourly net load[19] per month for the years 2020 through 2050 for the Baseline and High-Flexibility scenarios, respectively. We do not show the average hourly total load per month for 2030 through 2050, because they only have marginal increases compared to 2020. Furthermore, we do not show the Nuclear 60 scenario, because the average hourly net load per month is very similar to the Baseline scenario. In all scenarios, the total load data are the same (i.e., load is a model input) and are shown to be higher in winter months, with a peak in February, and lower in summer months. The seasonal pattern of load is impacted by higher electricity demand in winter and minimal need for cooling in summer.

In the Baseline scenario (Figure 13a), we see that the net load begins reducing during summer in 2020 as a result of production from PV while remaining high in winter. While the net load remains high in the winter of 2030-2050, it plummets to under 5 GW and under 3 GW in the summer of 2030/2040 and 2050, respectively. The reduction of the net load in the summer months is directly attributable to the cumulative PV installations leading up to each corresponding year. Interestingly, the net load in 2040 is higher than in 2030. Although the PV investments increase slightly between 2030 and 2040, this impact is compensated by the increase in total load. In 2050, we observe the largest seasonal deviation of the net load. In fact, there is a 5.6 GW difference between the highest (7.8 GW) and the lowest (2.4 GW) monthly values in 2050. The progression from 2020 to 2050 highlights the increasing seasonality of the net load profile and the corresponding need for seasonal flexibility in future years. In 2050 we observe a

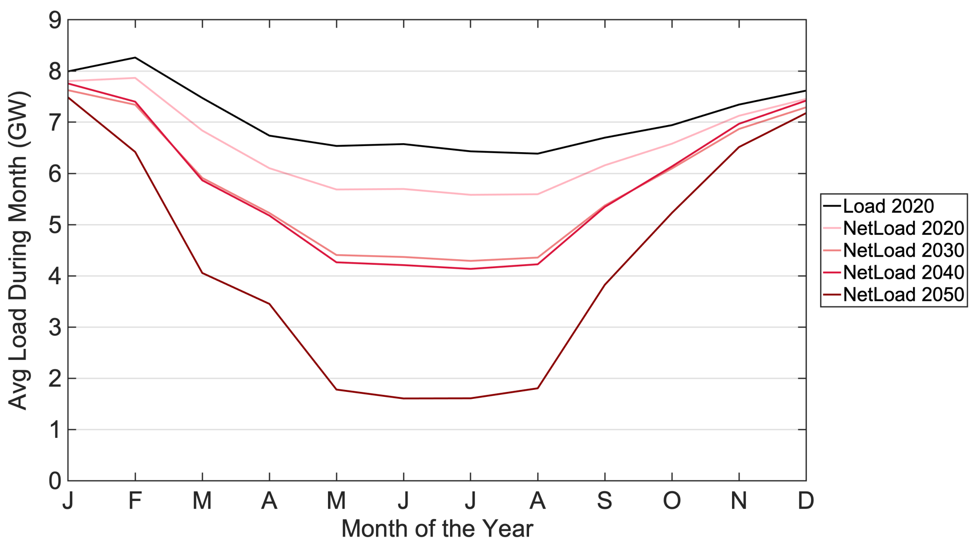
[19] Net Load = Load - (Wind + PV production)

significantly greater demand for power in winter months than in summer. This trend could influence the operational behavior of hydro storage power plants and other power generators as well as the seasonal pattern of imports and exports.

In the High-Flexibility scenario (Figure 13b), the net load plunge during summer is even more pronounced than in the Baseline scenario, especially in 2050 as more PV are installed (i.e., 4.65 GW more by 2050). In 2050, the lowest average hourly net load drops below 2 GW between May and August, resulting in a difference of more than 5.6 GW between the summer and winter seasons.



(a) Baseline



(b) High Flexibility

Figure 13: The need for seasonal flexibility is highlighted in the average hourly load and net load over each month of the year in 2020 through 2050. Data shown are from the Baseline and High-Flexibility scenarios. Nuclear-60 scenario average net loads are very similar to the Baseline scenario.

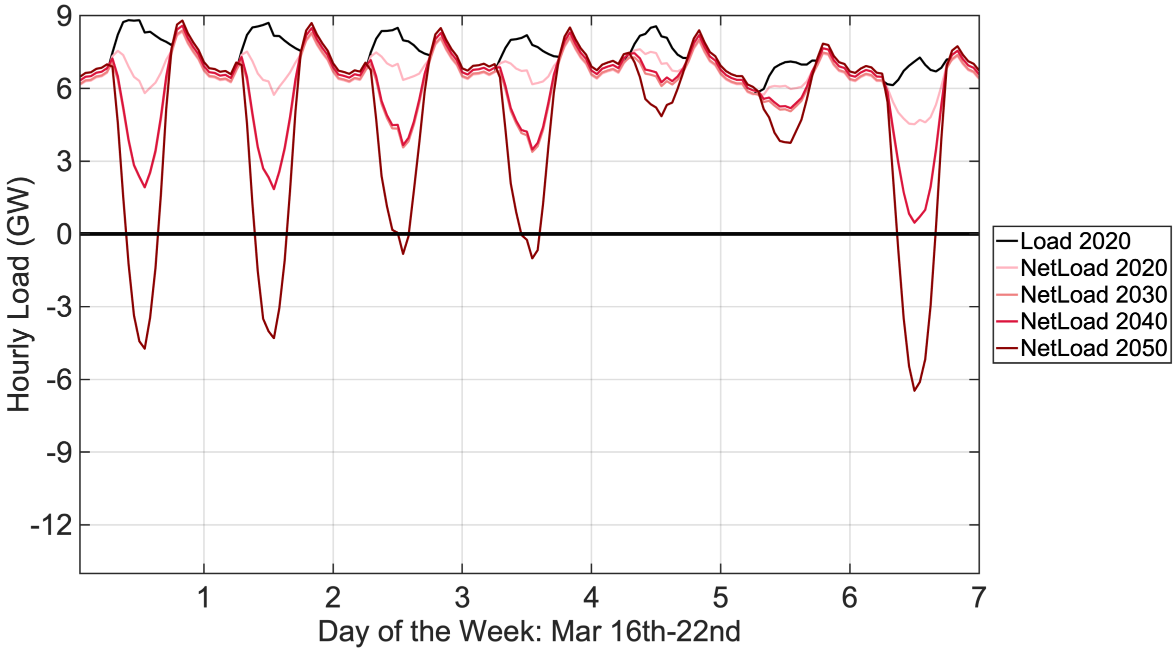
4.2.2 Daily and hourly

Figures 14 and 15 show the hourly load for 2020 and net load for the years 2020 through 2050 for one week in March and one week in May for the Baseline and High-Flexibility scenarios. In this section, and in Section 4.3.2, these two weeks are used to demonstrate the needs and supply of flexibility in Switzerland. The March week is selected because it represents the general load pattern in winter, it is near the period in late winter when the Swiss dam reservoirs are at their lowest levels, and it includes days with both sunny and cloudy conditions. The May week is selected because it represents the general load pattern in the summer and it contains days with both sunny and cloudy conditions. We do not show the hourly total loads for 2030 through 2050, because they only have marginal increases compared to 2020. Furthermore, we do not show the Nuclear-60 scenario, because the hourly net loads are very similar to the Baseline scenario. We selected weeks that show both sunny and non-sunny days because such occurrences, which are common, create more dynamic conditions of the net load profiles that help illustrate the need for flexibility. Once again, the total load profiles are the same in all scenarios. In both weeks, the total load follows a similar pattern with higher consumption during the day and less at night. This pattern is maintained during the weekends (last two days shown in the plots) but the weekdays have a higher load level than that of the weekend[20]. The total demand in both March and May days is relatively consistent between 5-9 GW in each hour, with March having a somewhat higher level. However, the March days are distinguishable from the May days by their double peak behavior, i.e. there is a morning demand peak in winter and then later another evening demand peak. This pattern is common in cold climate regions and is not as distinguishable in the summer when demand is driven more by high afternoon temperatures.

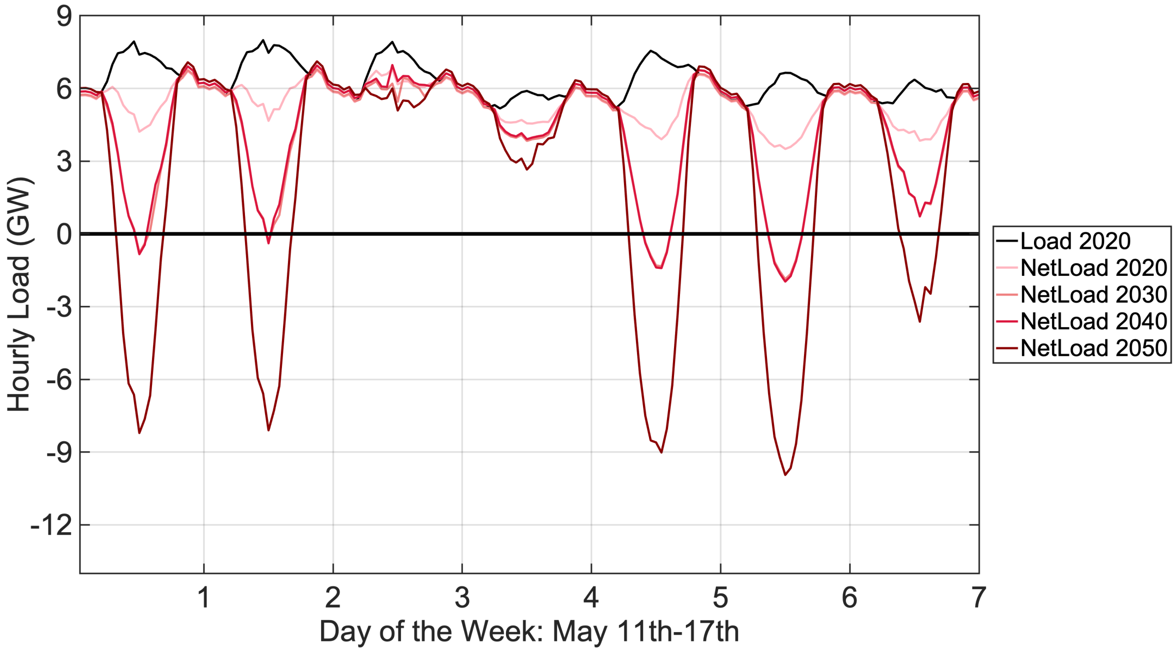
In each week of both scenarios, the net load profiles begin to separate further and further from the total load profile during the afternoon hours when PV is generating. By 2050, every sunny day in either March or May follows a highly dynamic plunge and recovery pattern. The net load profiles of 2030 and 2040 are quite similar because there is only a small increase in both load and in PV installations in 2040. In the Baseline scenario (Figure 14), it can be seen that the average net load can vary drastically from one day to the next (e.g., May 13th and 14th are cloudy days, followed by very sunny days on May 15th and 16th) and also from one hour to the next (e.g., during midday of a sunny day the net load is at a minimum but within hours it climbs all the way back up to the evening peak). Both phenomena become more pronounced as the PV penetration level increases from 2020 to 2050. Day-to-day and hour-to-hour differences become larger (i.e., the variations between a sunny day and a cloudy day are stronger and the afternoon plunge and recovery pattern within a day becomes more drastic). These results highlight that in 2050 on a sunny summer day the Swiss PV production could be twice as much as the total Swiss load, and the net load could ramp down or up by nearly 20 GW within a few hours. The increasingly dynamic pattern of the net load on an hourly basis emphasizes the future need for short-term flexibility resources that can quickly ramp up and down to supply the remaining Swiss demand. Similarly, the diverging daily patterns between sunny and cloudy days asserts the need for flexible resources that can be scheduled and dispatched to make capacities available over daily timescales. Both trends could influence the need for new capacities or operational behaviors of existing generators, such as: dispatchable units like hydro dams and gas-fired generators along with storages and load shifting units like pumped hydro, BSS, or DSM. The highly dynamic hourly trends could also require curtailment of non-dispatchable units like wind, PV, or RoR hydro. Finally, the daily pattern with very low net load in the afternoon could have a significant impact on the operation of storage units that could benefit by charging during the afternoon hours when net load is lowest.

In the High-Flexibility scenario (Figure 15), the hourly net load drops even further and more rapidly during the sunny May afternoon as a result of the additional PV generation compared to the Baseline scenario. However, these net load profiles do not yet account for the load shifting by BSS or DSM that have already been shown to be built in 2050.

[20] The day in the middle of the May week with low demand is a public holiday.

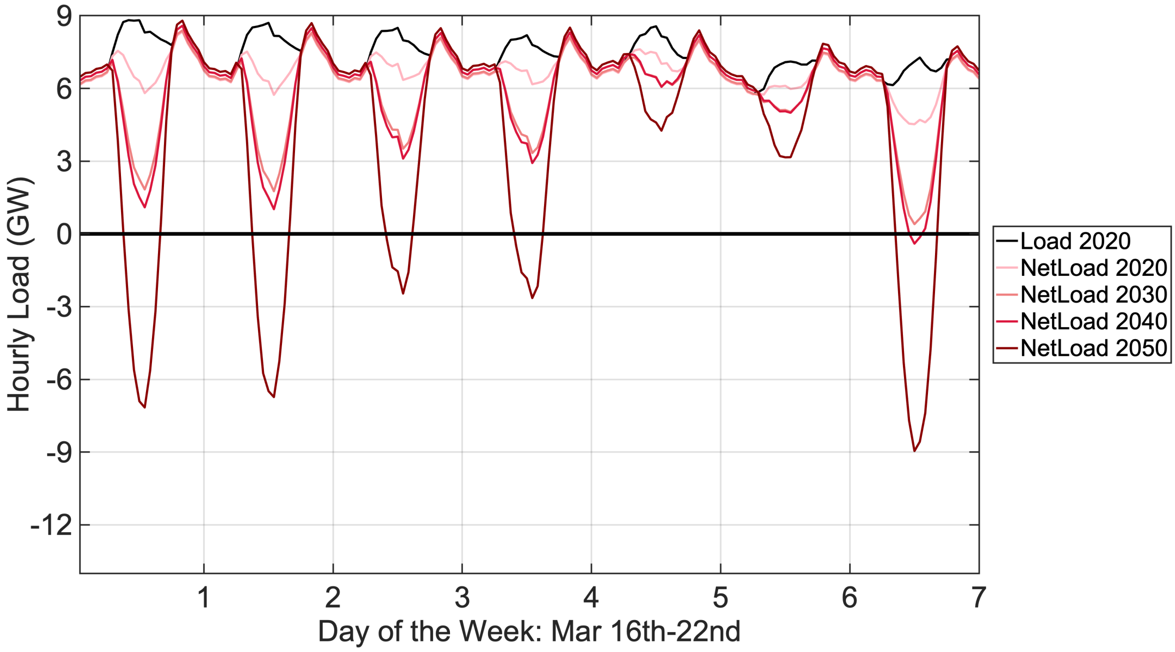


(a) March - Baseline

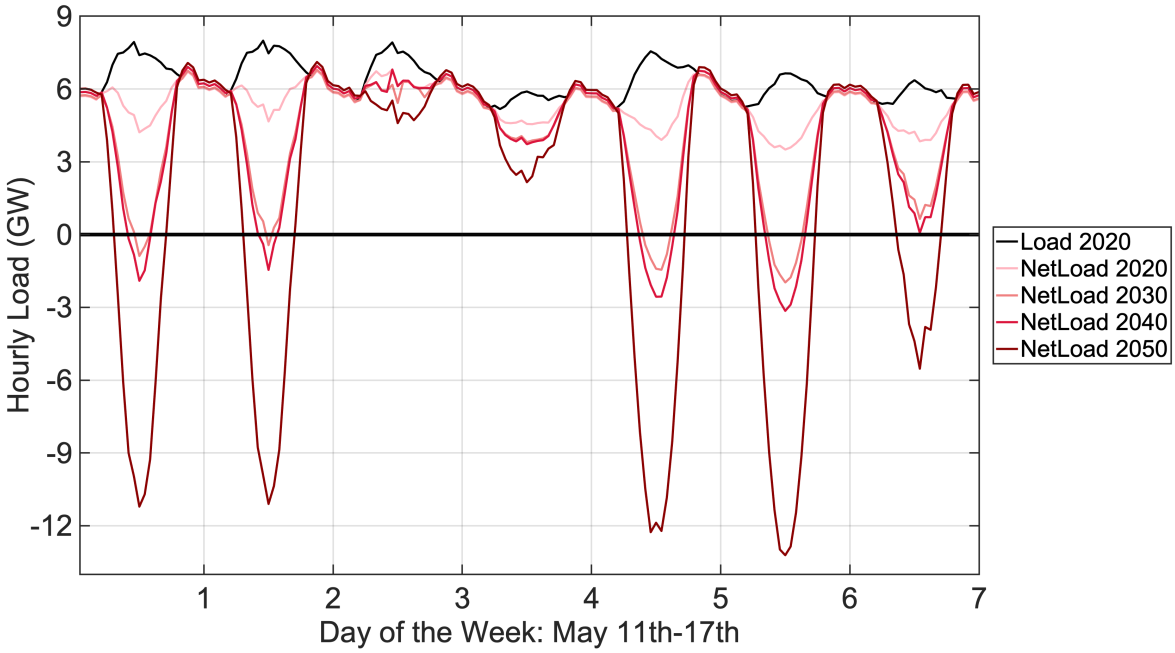


(b) May - Baseline

Figure 14: The need for hourly flexibility is highlighted in the hourly load and net load over a week in March and May of 2020 through 2050. Data shown are from the Baseline scenario. The Nuclear 60 hourly net loads are very similar to those of the Baseline scenario.



(a) March - High Flexibility



(b) May - High Flexibility

Figure 15: The need for hourly flexibility is highlighted in the hourly load and net load over a week in March and May of 2020 through 2050. Data shown are from the High-Flexibility scenario.

4.2.3 Sub-hourly

To provide the basis for the needs of flexibility on the sub-hourly timescales, methods will first be described that account for the need to supply increased reserve requirements to cover the added uncertainties introduced to the supply/demand balance (**Reserve procurement**). A second section will focus on the method of assessing the short-term response of the transmission network and reserves to handle the possible cascading impacts of component failures (**Grid reliability**).

Reserve procurement

Within Nexus-e, several modules represent the procurement and deployment of reserves that are needed to compensate for sub-hourly effects of unit outages, load variability, and short-term forecast errors. Traditionally, capacity reserves provide the necessary backup power to cover the loss of a generator or a load as well as for balancing the random variability in demand. As more weather-dependent RES resources are integrated, utilizing reserves to compensate for the forecast errors that these resources introduce, is becoming more ubiquitous. To account for this increasing need for flexibility, CentIv utilizes a method previously developed in [6] to quantify the additional reserves needed for any amount of newly installed wind or PV capacity. Details of this method can be found in Appendix A. This method utilizes data for the wind speed and solar irradiance across Switzerland on a 10-minute basis [47] along with short term forecasting techniques (less than one hour-ahead) [48] to apply statistical methods for assessing the distribution of forecast errors and associated reserves needed [49, 50, 51, 52] at increasing levels of added wind and PV capacity.

Table 9 shows the starting value (Base) for the annual average hourly reserve requirements[21] along with how the reserves increase over time as new PV investments are added in Switzerland. First, the secondary reserve requirements remain unchanged to reflect the current procedures of Swissgrid to include RES forecast errors into the quantification of only tertiary reserve requirements [53]. In the Baseline scenario, the tertiary requirements increase from year-to-year as new PV investments are added. The larger jumps between 2020–2030 and 2040–2050 correspond to the timing of the PV capacity increases. Overall, the increases in tertiary requirements are noticeable, adding around 200 MW to both upward and downward reserves in 2050 compared to the Base requirement. These additions are substantial considering the Base requirements for upward and downward are 227 MW and 442 MW, respectively.

Table 9: The base reserve requirements and how they increase over time in [MW] for the three modeled scenarios.

Scenario	Reserve	Base [MW]	2020 [MW]	2030 [MW]	2040 [MW]	2050 [MW]
All	Secondary Up	379	379	379	379	379
	Secondary Down	379	379	379	379	379
Baseline	Tertiary Up	227	255	316	322	425
	Tertiary Down	442	471	536	543	653
Nuclear 60	Tertiary Up	227	254	314	318	424
	Tertiary Down	442	471	535	540	653
High Flexibility	Tertiary Up	227	255	317	333	463
	Tertiary Down	442	471	537	554	692

In comparison to the Baseline scenario, both the Nuclear-60 and High-Flexibility scenarios follow similar trajectories for the reserve requirements over time. The most notable difference is seen in the

[21] These ‘Base’ reserve requirements were provided by Swissgrid [33].

2050 High-Flexibility scenario, where the greater amount of installed PV leads to similarly higher tertiary requirements compared to the Baseline.

Grid reliability

Although the Nexus-e platform does not include power system dynamic aspects that directly address sub-hourly imbalance issues, Cascades does represent the short-term response of UFLS along with the deployment of reserves that occur in response to frequency deviations. The system frequency is affected by local contingencies and, possibly, by the subsequent cascading outages (systemic failures), if they result in loss of generator or loss of load in the system. If the frequency decrease is outside the predefined margins, the UFLS is performed. Otherwise, the load-generation-balance is restored by frequency control, i.e., primary frequency control responds in few seconds (active up to 30 seconds), secondary frequency control responds between 15 and 30 seconds (active up to 15 min), and tertiary frequency control responds after several minutes (activated within 15 min). Overall, the system uses the available generating reserves to restore the system frequency. Therefore, the amount of available and dispatchable (flexible) units and their location in the grid will affect system stability and determine if all load will be supplied. In case that insufficient generation flexibility exists, the frequency stability is restored by load shedding. In general, the lack of flexibility in the power system will have a negative effect on the system security and, thus, will contribute to the risk of systemic failures. Note that the system security is influenced by multiple factors, including the generation mix, the share of dispatchable units in the mix, their ramp rates, the location of the units in the grid, the transmission capacity, the demand, and the imports/export, which are collectively captured by the integrated modules of Nexus-e.

Particularly, as the amount of installed PV capacity increases, greater challenges are posed to grid reliability. One example of how the installation of PV may affect the system security is the following scenario: during low power injections from PV, it can occur that much of the dispatchable generation is used to supply the demand, which is more likely to be the case when nuclear power is unavailable. This mode of operation erodes the margin of flexibility provision by dispatchable generation. If in such a scenario, contingencies occur which ultimately lead to a generator trip, there will be a need for the system to restore the load-generation-balance. In such a case, however, the reduced amount of available dispatchable generation will have an effect on the stabilization of the frequency and, therefore, can result in DNS. Details on how the grid reliability evolves over years and under different scenarios are presented in Section 4.3.3.

4.3 The system's supply of flexibility

This section describes the scenario results from the modules of the Nexus-e platform, that together address the supply of flexibility across the timescales previously introduced (seasonal, daily, hourly, and sub-hourly). The following subsections provide details on how flexibility needs are addressed for (i) seasonal patterns of generation and demand (Section 4.3.1), (ii) daily and hourly fluctuations in the net load (Section 4.3.2), and (iii) sub-hourly services for system stability and frequency control (Section 4.3.3).

Key takeaways:

- The phase-out of nuclear power and the increasing investments in PV over time lead to a strong seasonally-dependent net import profile for Switzerland that follows closely the seasonal net load pattern, indicating that imports and exports are essential flexibility providers to balance seasonal variations. Additionally, the dynamics of the seasonal hydro dam pattern increases over time, indicating an increasing importance on hydro dams for providing seasonal flexibility.
- In the Nuclear-60 scenario, Switzerland becomes less import dependent in 2030 and 2040 because the additional nuclear generation drives down imports in winter and increases exports in summer. Similarly, in the High-Flexibility scenario, Switzerland becomes less import dependent in 2050 because the extra PV investments lead to lower imports in winter and higher exports in the summer (the latter impact being the more prominent).
- Swiss generators also have to adjust their operation to account for the increasingly rapid changes in the hourly net load. Hydro dams, hydro pumps, hydro RoRs, BSS, DSM, as well as imports and exports all react rapidly to help provide the necessary supply to match the daily plunge and recovery pattern of the net load. While all these flexible resources are regularly used, the imports and exports along with hydro dams play the leading roles for providing hourly flexibility.
- In the 2050 High-Flexibility scenario, flexible BSS and DSM resources in the distribution system successfully smooth the hourly net load and thus reduce the reliance on imports/exports for hourly flexibility.
- The existing Swiss dispatchable capacities supply the flexibility, in the form of reserves, necessary to cope with the sub-hourly forecast uncertainty of PV investments in all scenarios (e.g., over 30 GW in the High-Flexibility scenario).
- In all cases, the risk of systemic failures increases compared to the 2015 reference year. However, the High-Flexibility scenario is shown to have lower risk than the other scenarios because BSS and DSM improve system flexibility. In all scenarios, system security is restored to a level similar to the 2015 reference year with only a couple of transmission line upgrades.
- In all scenarios, no new gas-fired generators are built in Switzerland, indicating that the existing capacities along with imports and exports and added distribution level units are able to adequately supply the flexibilities required to balance seasonal, daily/hourly, and sub-hourly issues[22].

4.3.1 Seasonal

Figures 16 (2020-2030) and 17 (2040-2050) show the Swiss monthly results for electricity generation by technology type, imports and exports, load, net load, and net imports for each year of the Baseline scenario. Similarly, in Appendix D, Figures 34 and 35 show the monthly results for the Nuclear-60

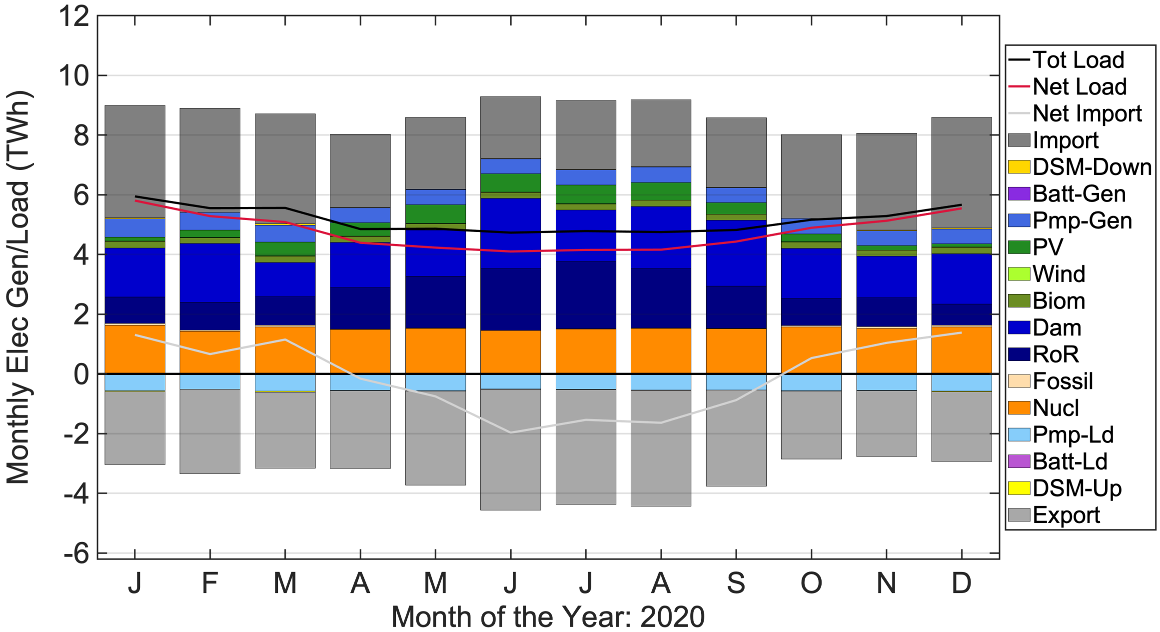
[22]We model four gas power plants in Switzerland in 2015 which we assume to remain operational until 2050 (2 gas SC units (1x27 MW and 1x36 MW) and 2 gas CC units (1x55 MW and 1x46 MW)). The 2 gas CC units are utilized in around 20% of the year 2050 while the gas SC units are utilized in around 0.25% of the year. Together these units provide less than 0.25% of the annual Swiss demand in 2050. Similar results were found in all other years.

scenario while Figures 36 and 37, show the monthly results for the High-Flexibility scenario.

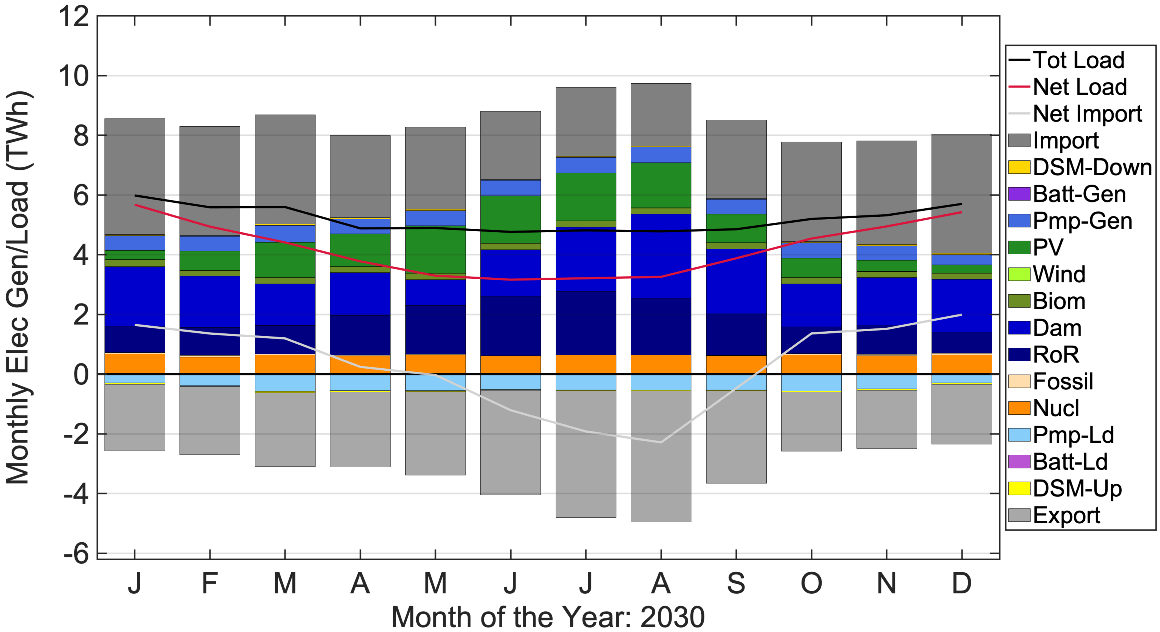
In the Baseline scenario, Figures 16 and 17 show the growth in PV generation in each successive year and the resulting increase in seasonality of the net load profile. In particular, in 2050 the net load in summer months is around 2 TWh while in 2020 it was twice as high. Additionally, the Swiss net imports (light grey line) are increasing during the winter months in all future scenario-years, and are particularly high in 2040. On the other hand, exports predominantly occur in the summer months in all years except in 2040. The latter is a result of the completed nuclear-phase out and minimal increase in PV installations in 2040. In the summer months, mostly solar and hydro (and nuclear when available) supply the demand. While in the winter months, mostly hydro and imports (and again nuclear when available) supply the demand. We can observe RoR is producing more in summer than in winter, because of the higher natural inflows in summer. However, the RoR production in the summer of 2050 is lower because of curtailments, which help to achieve the low summer net load during that year. Figures 16 and 17 also show that the net imports in all years follow a seasonal pattern (high in winter and low in summer). From year-to-year this pattern becomes more seasonally pronounced (i.e., even higher in the winter and even lower in the summer). The increase in the dynamic of this pattern more and more begins to follow the seasonal dynamic of the net load pattern. Finally, hydro dams continue to follow a general seasonal pattern but similarly, the dynamic of that pattern increases as more production is shifted to the winter months and less in the spring and fall months (also a little reduction in some summer months, but also an increase in some summer months).

The Nuclear-60 scenario (Figure 18 shows 2030 for both the Baseline and the Nuclear-60 scenarios for easier comparison), has significantly higher exports in the summer months in 2030 and 2040 (not shown) compared to the same years in the Baseline scenario. In particular, in 2030, the annual net exports are over 6 TWh, which is the highest for any scenario and year simulated. No other significant difference exists between these two scenarios in terms of the seasonality of the power supply. And by 2050, the two scenarios are nearly identical.

In the High-Flexibility scenario (Figure 19 shows 2050 for both the Baseline and the High-Flexibility scenarios), all the scenario-year results are very similar to the Baseline except 2050. The greater PV investments in the 2050 High-Flexibility scenario lead to even higher net exports in the summer months compared to the Baseline scenario. Furthermore, there is significant participation of the PV-batteries in providing flexibility during the more sunny months in 2050.

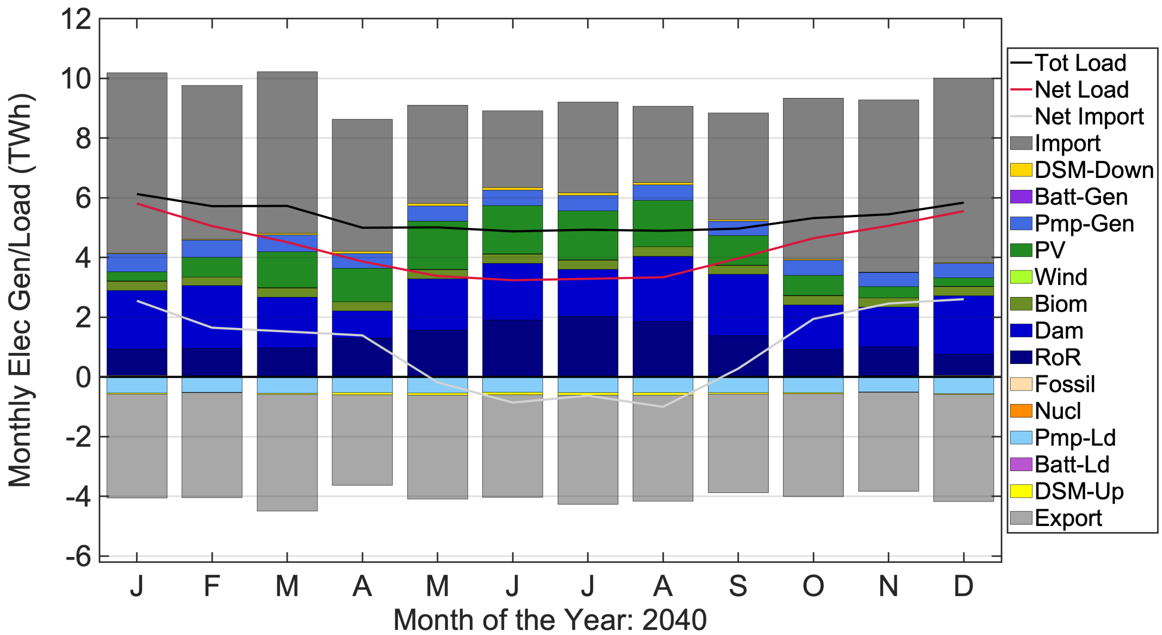


(a) 2020 - Baseline

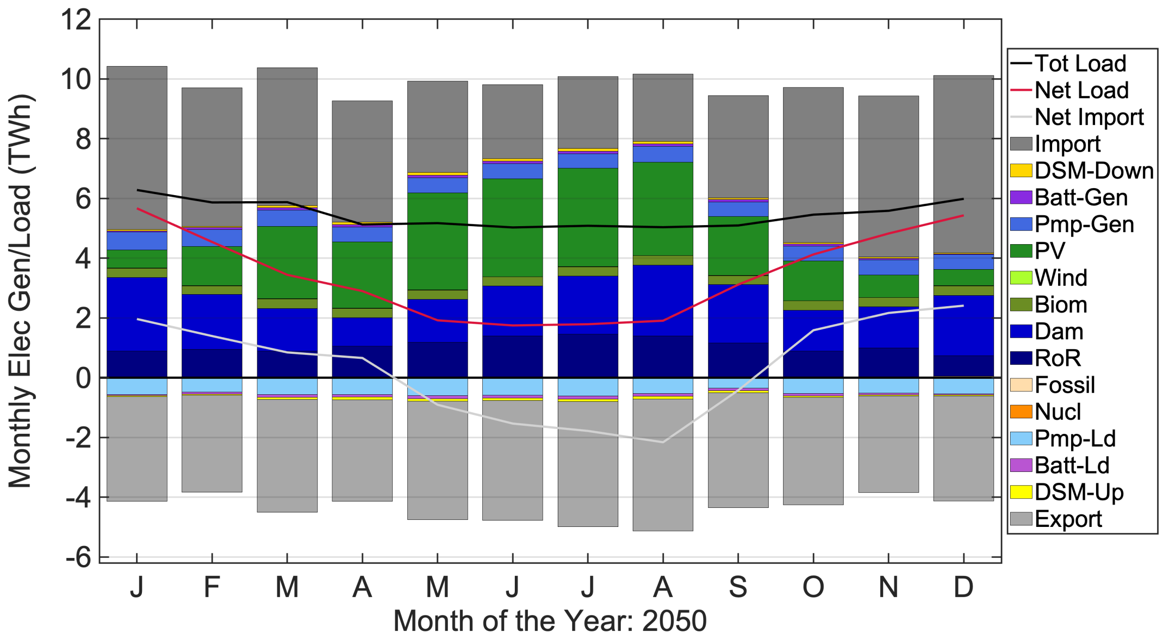


(b) 2030 - Baseline

Figure 16: Monthly electricity generation by technology type for the years 2020 and 2030. Data shown are from the Baseline scenario.

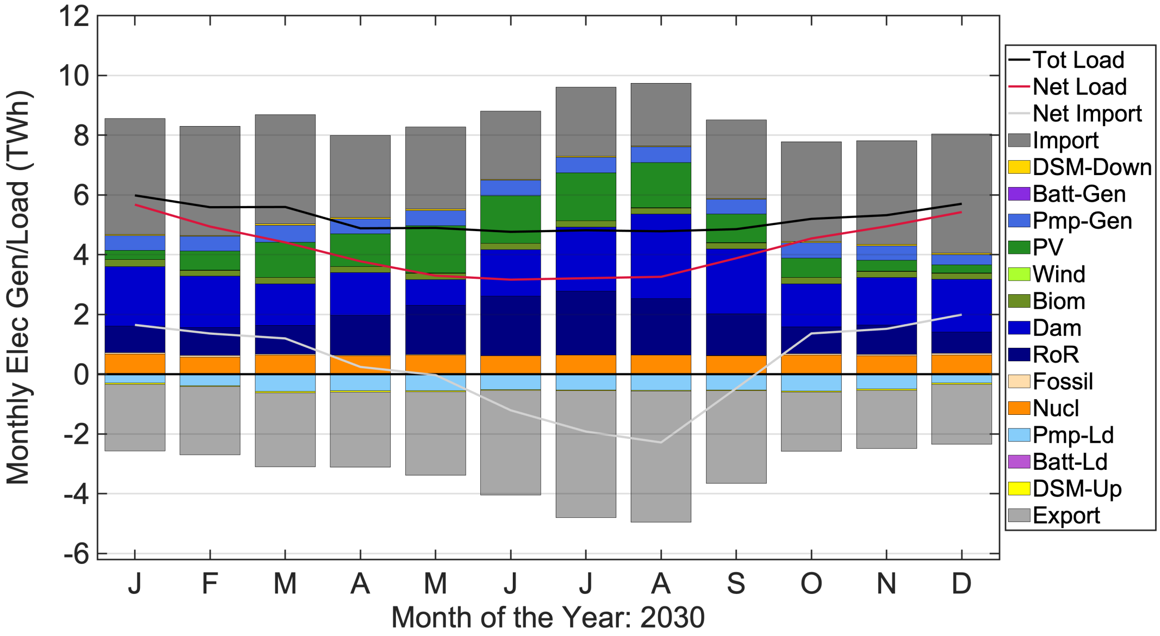


(a) 2040 - Baseline

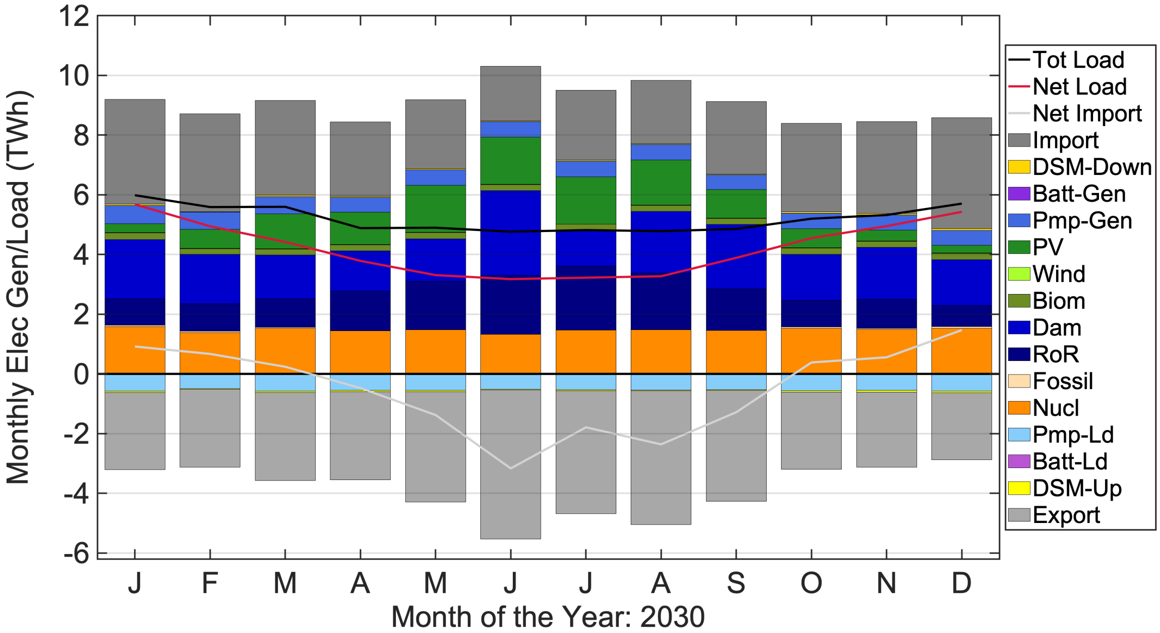


(b) 2050 - Baseline

Figure 17: Monthly electricity generation by technology type for the years 2040 and 2050. Data shown are from the Baseline scenario.

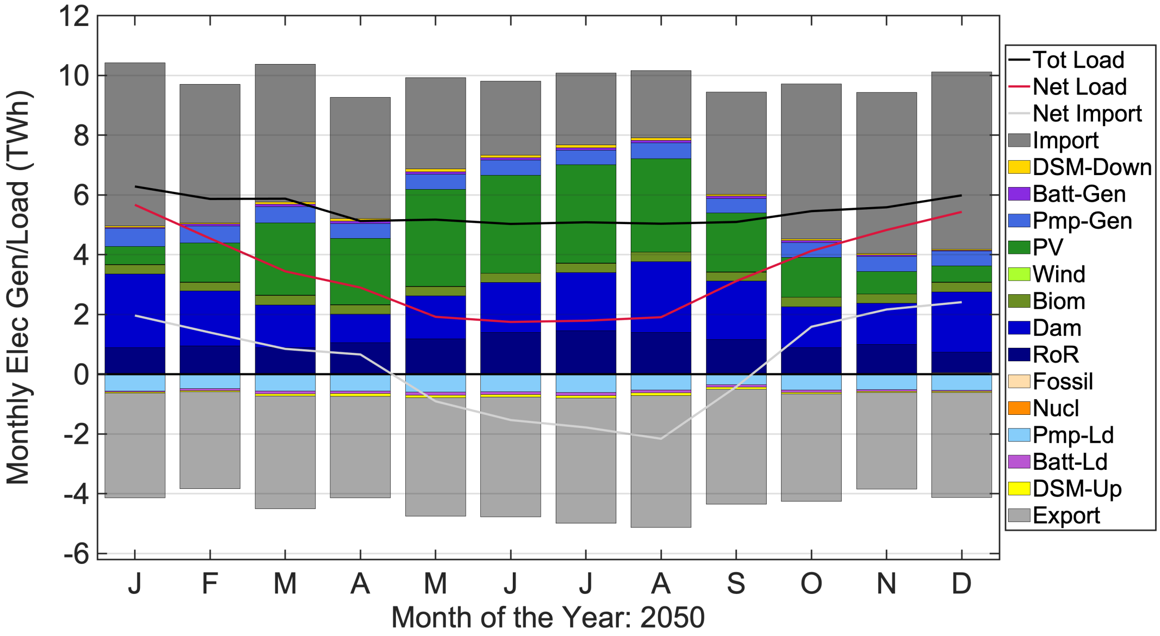


(a) 2030 - Baseline

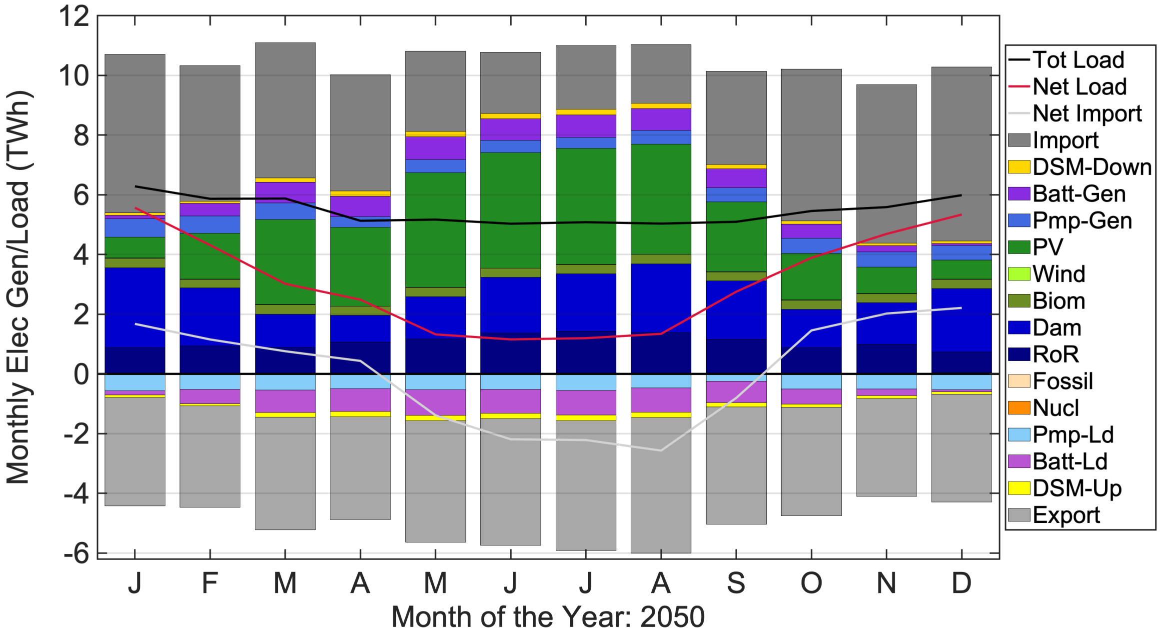


(b) 2030 - Nuclear 60

Figure 18: Differences in the monthly generation by technology type in 2030 between the Baseline and Nuclear-60 scenarios. The presence of more nuclear capacity in the Nuclear-60 scenario drives down net imports.



(a) 2050 - Baseline



(b) 2050 - High Flexibility

Figure 19: Differences in the monthly generation by technology type in 2050 between the Baseline and High-Flexibility scenarios. The greater PV investments in the High-Flexibility scenario lead to even higher net exports in the summer months.

4.3.2 Daily and hourly

To present the results for the supply of flexibility on the daily and hourly timescales, we show first the results that account for production from both the centralized and distributed levels (**Full system perspective**). These results will highlight the dynamic behaviour of all flexibility providers across all scenarios and scenario-years. A separate section will focus on the distribution level (**Distribution system perspective**) to highlight the key differences in the use of BSS and DSM in 2050 in the High-Flexibility scenario.

Full system perspective

Figure 20 shows the Swiss hourly results for electricity generation by technology type, imports and exports, load, net load, and net imports for the May week of the 2020 Baseline scenario. It highlights that Switzerland is both importing and exporting in almost every hour. Clearly the supply of Swiss demand is very dependent on both imports and exports but Switzerland is also an important transit country for power coming from some neighboring countries and going to other neighboring countries (i.e., from Germany/France to Italy). All remaining hourly plots will instead show only the Swiss net imports (light grey line) to improve visualization and enable better understanding of how the import and export behavior changes in response to the increasing need for rapid net load ramping. Note that the consistent pattern of two consecutive similar days is an artifact of the simulation methods of both CentIv and DistIv that only model every other day of the year to reduce simulation runtime[23].

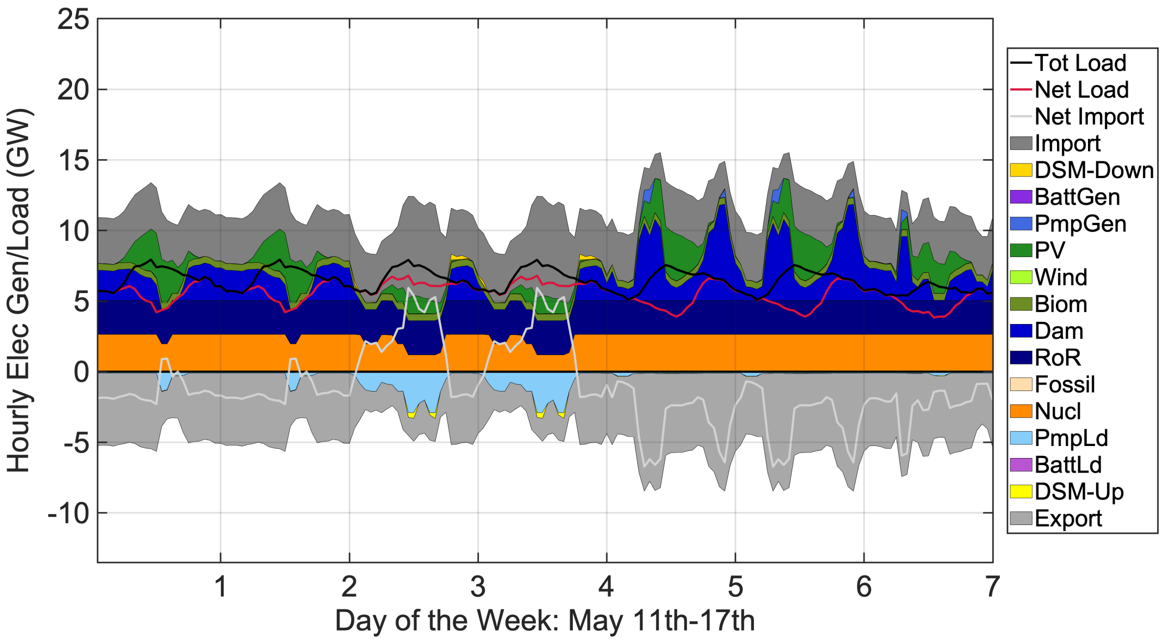


Figure 20: The hourly generation by technology type over a week in May in 2020. Data shown are from the Baseline scenario.

Figure 21 shows the Swiss hourly results for electricity generation by technology type, load, net load, and net imports over a week in March and May for each year of the Baseline scenario. Similarly,

[23]Both CentIv and DistIv include large-scale mixed-integer linear programming (MILP) formulations which are difficult to solve. To speed-up computations, while maintaining high temporal resolution and chronological accuracy, every other day of the year is simulated with hourly resolution (days in between are assumed to be identical to the previously simulated day).

Figures 38 and 39, presented in Appendix D, show the hourly results for the Nuclear-60 and High-Flexibility scenarios, respectively.

In the Baseline scenario, as was shown in Section 4.2.2, the net load variation increases as the PV investments grow from one year to the next. The severity of the net load dynamic behavior has a strong influence on the operation of Swiss generators as well as on the net behavior of imports and exports. The need for flexible resources to match the highly dynamic net load is most pronounced in the March and May weeks of 2050, shown separately and enlarged in Figure 22. During these weeks, hydro dams, hydro pumps, hydro RoRs, BSS, DSM, as well as imports and exports all react over a few hours to help provide the necessary supply to match the repeating plunge and recovery pattern of the net load. These net load ramping needs (especially in 2050) are satisfied mainly by the flexibilities provided by:

- Hydro dams: Dams transition toward being a 'peak' provider, generating during nights to better coordinate with the PV generation during the day;
- Pumped hydro units: Pump consumption behavior increases over the years and changes to consolidate charging into the minimum net load hours (middle of the day when PV is generating the most) and discharging during the early morning and evening hours when net load is high;
- Hydro RoR: RoR production is increasingly curtailed in the afternoon hours when PV generation peaks[24];
- Battery storage: in 2050, the BSSs provide flexibility by charging in the afternoon to absorb the excess PV generation and discharging during the evening when net load peaks;
- DSM: DSM helps to balance the net load variations by shifting the load within the day (i.e., decreasing load in the evening and early morning and increasing load during the most severe afternoon hours);
- Imports and exports: PV generation is increasingly exported to neighboring countries during mid-day hours while the electricity deficit in the evening is satisfied by importing.
- No new gas-fired generators are built in Switzerland in any scenario, which indicates such units are not needed to help balance the daily or hourly supply-demand mismatches that arise.

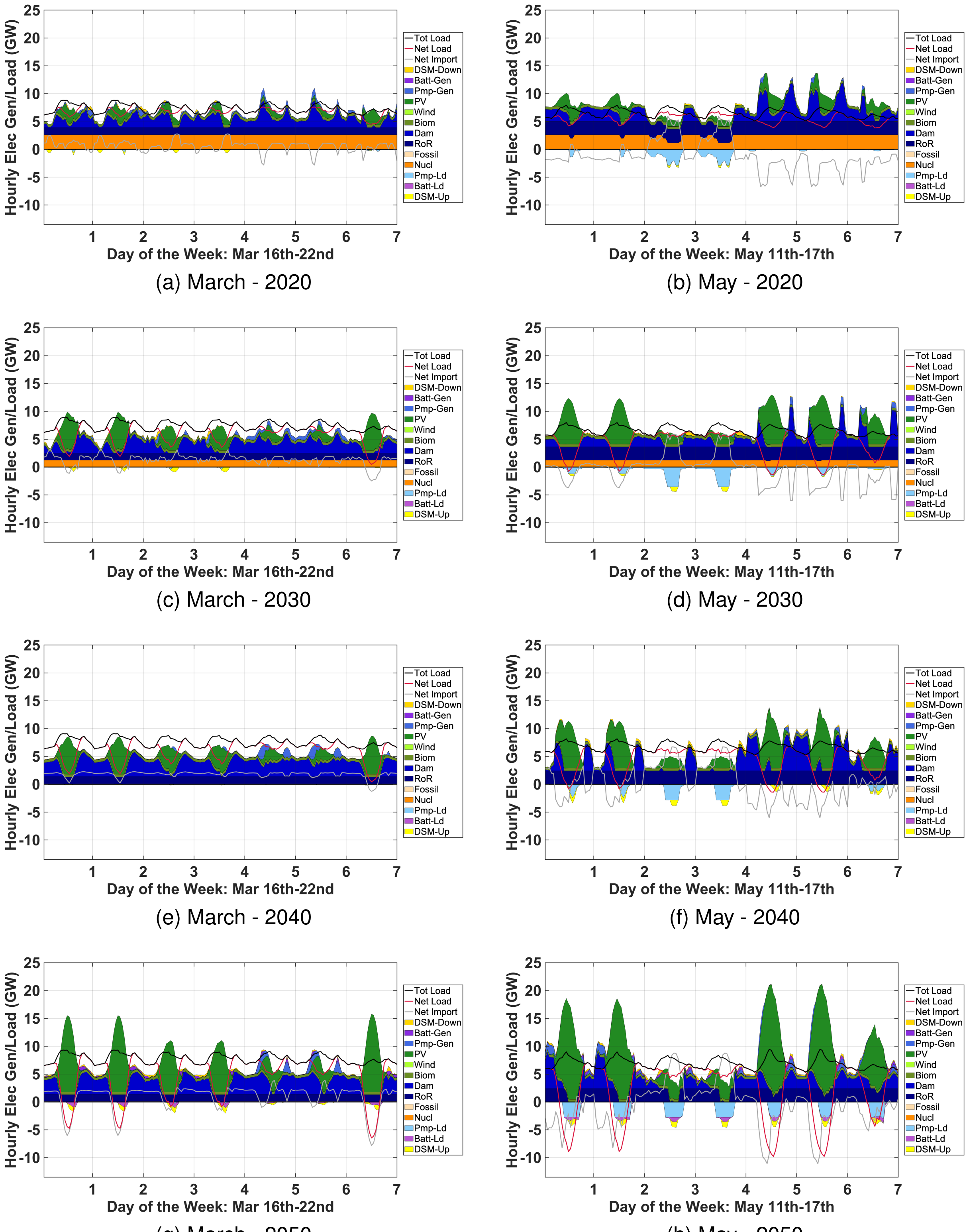
All forms of flexibility appear to be used regularly, but the operation of imports and exports along with hydro dams are the most prominent throughout the different years. From day-to-day, in many of the weeks shown, Switzerland transitions from an importer on a cloudy day to an exporter on the following sunny day. From hour-to-hour, Switzerland changes from an importer in the early morning to an exporter over a few hours. Hydro dams appear to have less operating differences from day-to-day but do show a highly dynamic behavior that becomes more concentrated in the evening and early morning hours in the later years. The results also show that during cloudy days, Switzerland imports more in the afternoon, likely because electricity prices are still low in these hours based on PV production in the neighboring countries. Similarly in the May week of 2020, Swiss nuclear production ramps down to take advantage of these hours when exporting is not needed but the prices of importing from the neighboring countries is still very low (this behavior is also attributable to our assumption that the operating cost for Swiss nuclear units is higher than the nuclear units in France and Germany). It is worth mentioning that the capability of modeling hourly dynamics allows Nexus-e to capture new behaviors of hydro pumps, BSS, and DSM across the unique scenarios, which is critical for modeling the Swiss electricity system and supply of flexibility.

The hourly results of the Nuclear-60 scenario are similar to that of the Baseline scenario except that the additional nuclear generation in 2030 and 2040 drives down imports in March (Figure 23 shows March 2030 for both scenarios) and increases exports in May (Figure 24 shows May 2030 for both scenarios). This shift toward greater exports results in a significant annual difference in the Swiss net import of electricity between the two scenarios. While in the Baseline Switzerland has annual net imports of 3.4 TWh and 11.7 TWh (in 2030 and 2040, respectively), in the Nuclear-60 scenario, Switzerland is

[24] By default, the most expensive units are curtailed first, and since Swiss RoR is modeled as more expensive than wind or PV, it is curtailed first

actually an annual net exporter of 6.2 TWh in 2030 and an annual net importer of 4.3 TWh in 2040 (i.e., shifts toward more exporting / less importing of 9.6 TWh and 7.4 TWh in 2030 and 2040, respectively). While their behaviors differ between scenarios, hydro dams and imports/exports play the leading roles for providing flexibility, with prominent dynamics shifts on an hourly basis.

The hourly results of the High-Flexibility scenario are similar to that of the Baseline scenario except in 2050 when there are higher investments in BSS and PV leading to even more PV production along with greater use of DSM because of the relaxed shifting limitations (Figure 25 shows May 2050 for both scenarios). While the immediate impact of the added PV production is an even deeper plunge and recovery of the net load (going to below -13 GW), the increased use of BSS and DSM result in a reduction of the necessary exports during the peak afternoon hours. The amount of RoR curtailments in the afternoon is also reduced. Additionally, the battery and DSM discharging, occurring over night, tends to shift the Swiss imports down during these hours to where Switzerland is actually a net exporter. Generally, the presence of more flexible resources in the distribution system, in the form of BSS and DSM, reduces the use of imports and exports as one of the main sources of flexibility compared to what would be expected for this higher PV production if the BSS and DSM were kept at a level equivalent to the Baseline scenario.



(a) March - 2020

(b) May - 2020

(c) March - 2030

(d) May - 2030

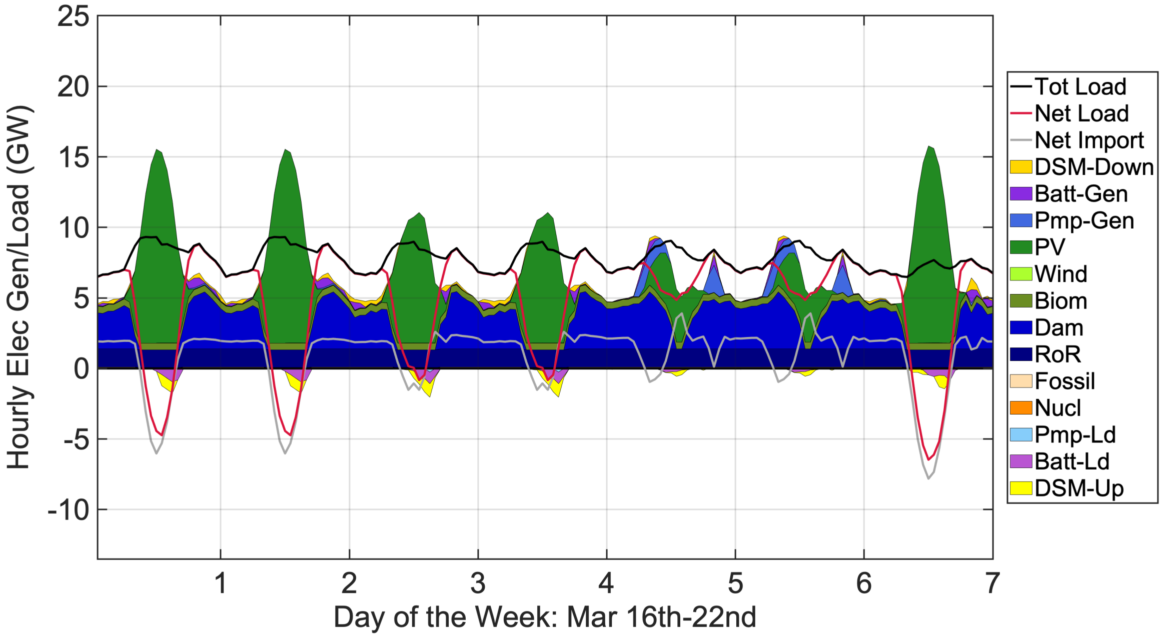
(e) March - 2040

(f) May - 2040

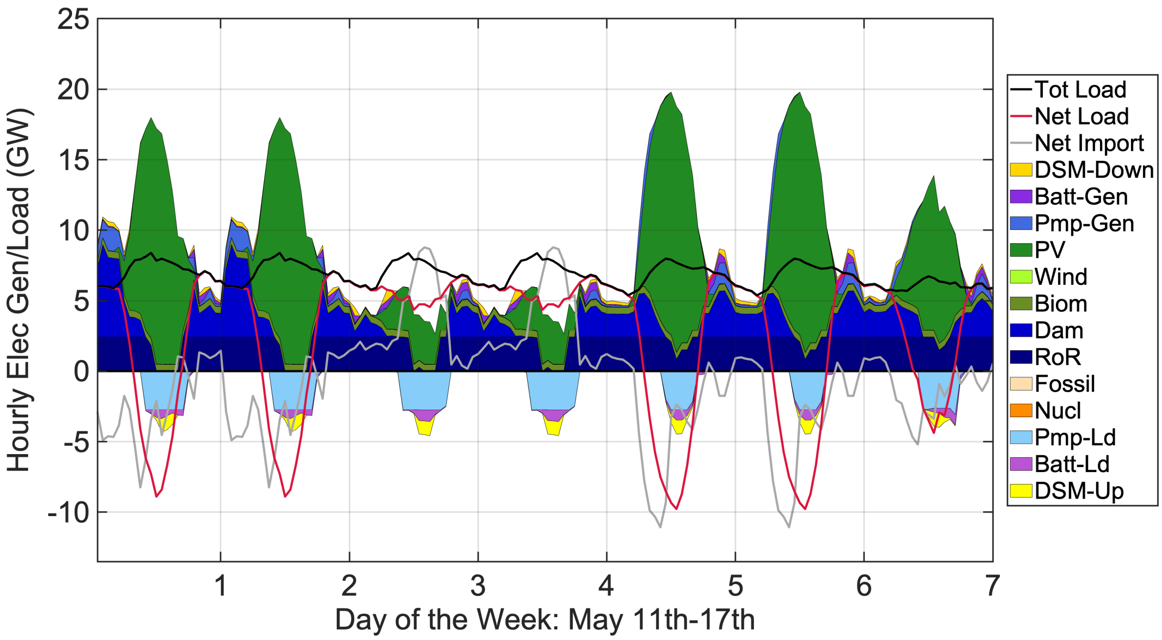
(g) March - 2050

(h) May - 2050

Figure 21: The supply of hourly flexibility is illustrated in the hourly generation by technology type over a week in March and May in 2020 through 2050. Data shown are from the Baseline scenario.

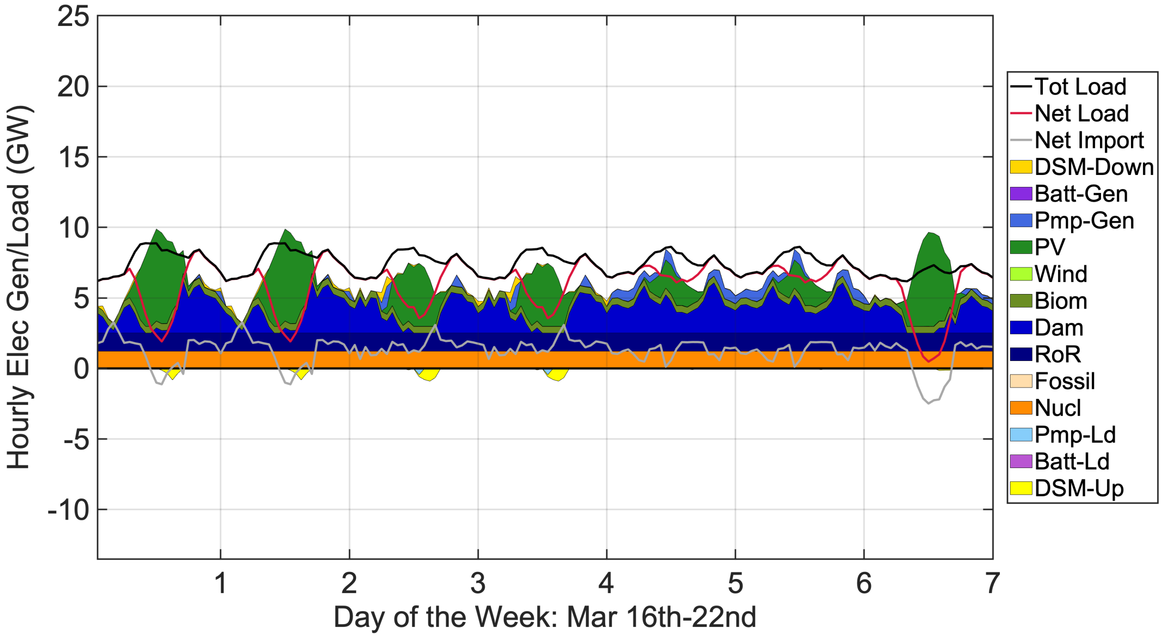


(a) Baseline - March - 2050

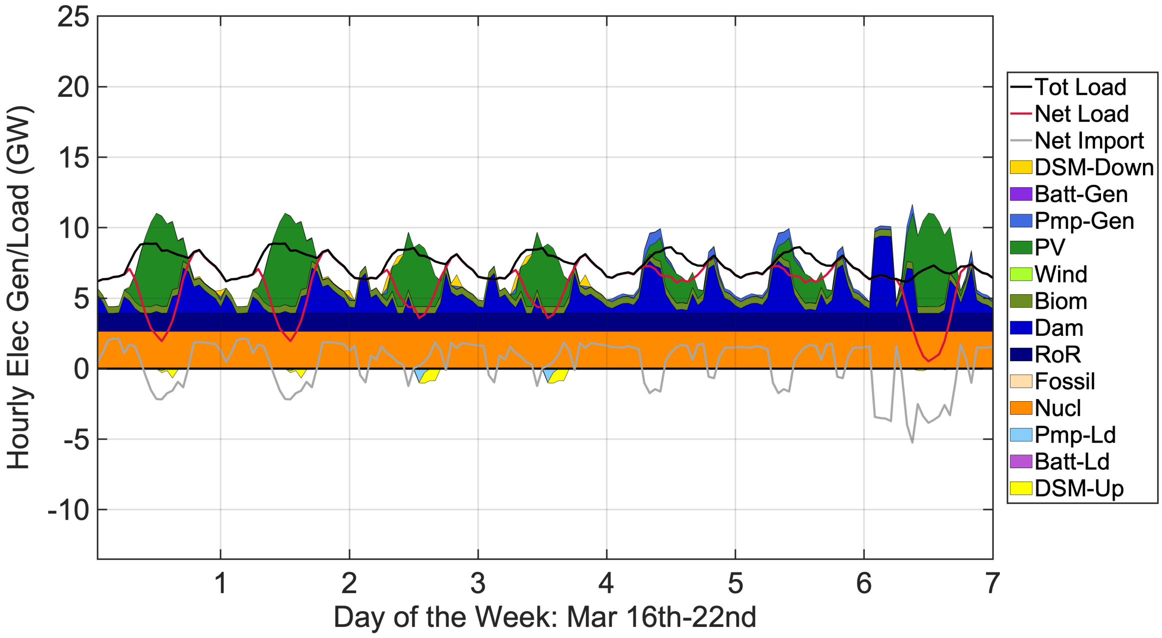


(b) Baseline - May - 2050

Figure 22: For the Baseline scenario, the need and supply of hourly flexibility is most severe in 2050. Hydro dam, hydro RoR, pumped hydro, BSS, DSM, as well as imports and exports all react over a few hours to help provide the necessary supply to match the massive plunge and recovery of net load.

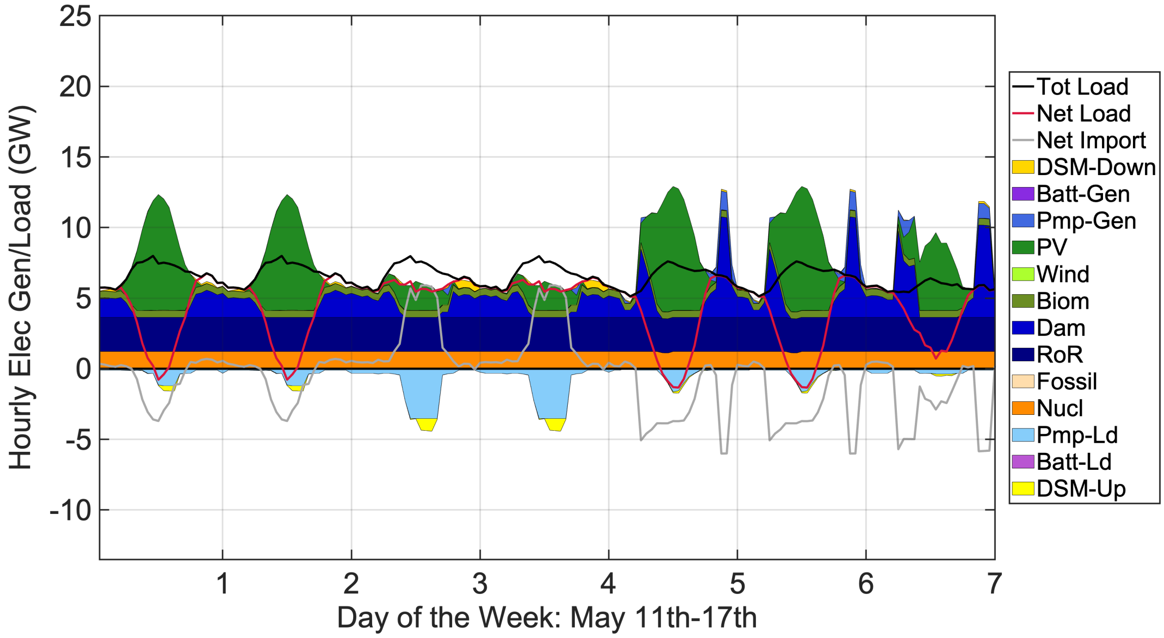


(a) Baseline - March - 2030

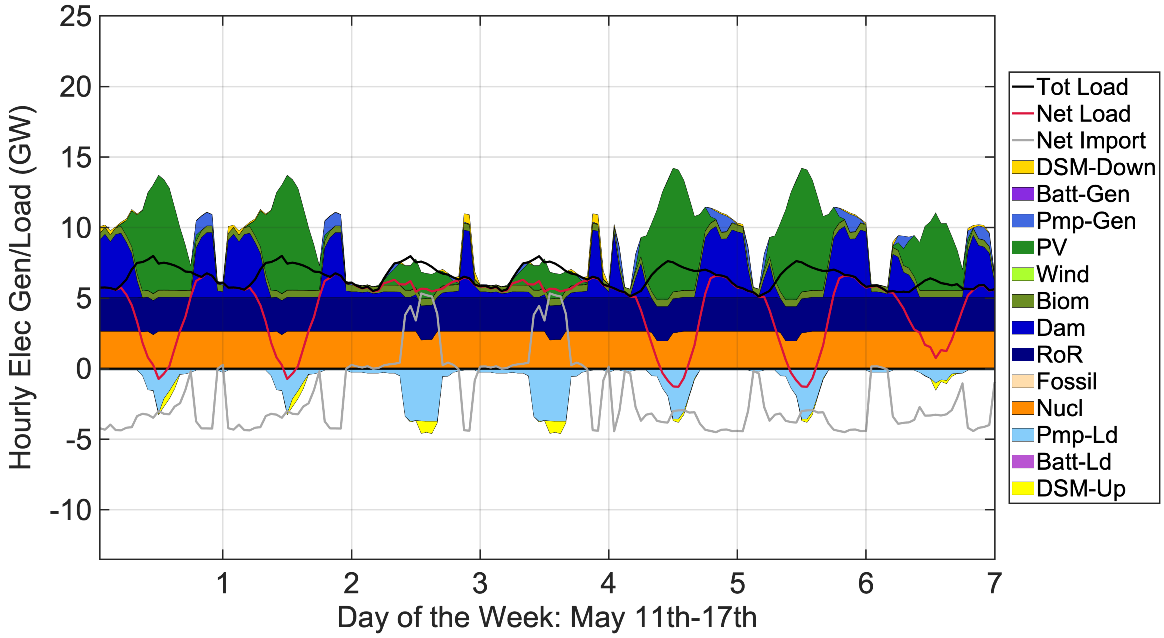


(b) Nuclear 60 - March - 2030

Figure 23: Differences in the hourly generation by technology type over the March week in 2030 between the Baseline and Nuclear-60 scenarios. The presence of more nuclear capacity drives down imports.

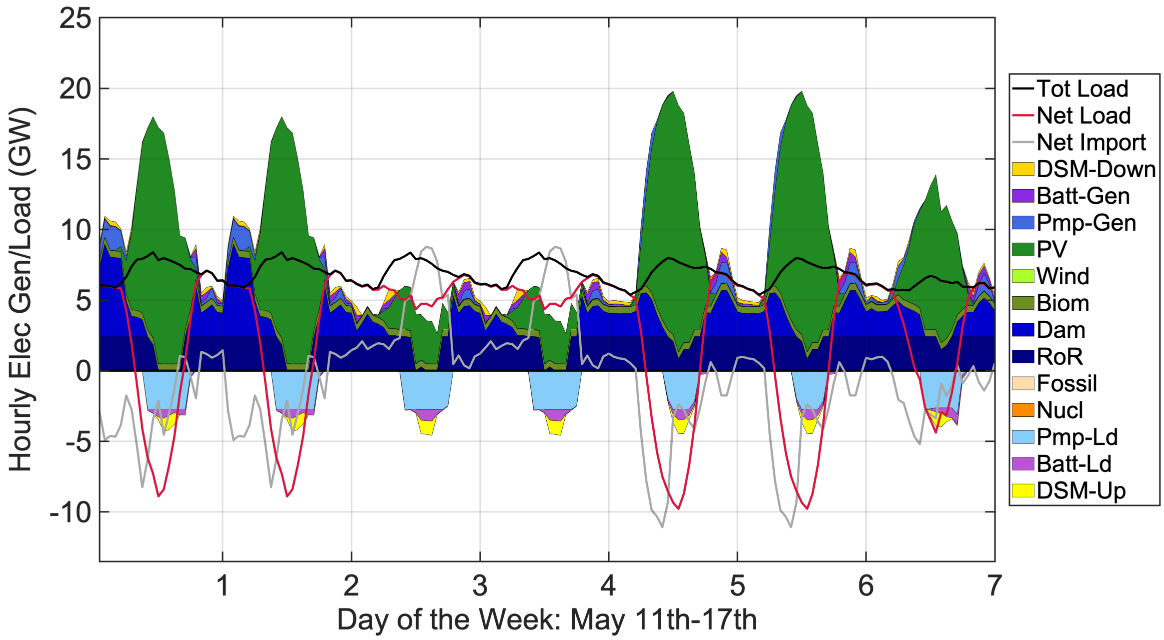


(a) Baseline - May - 2030

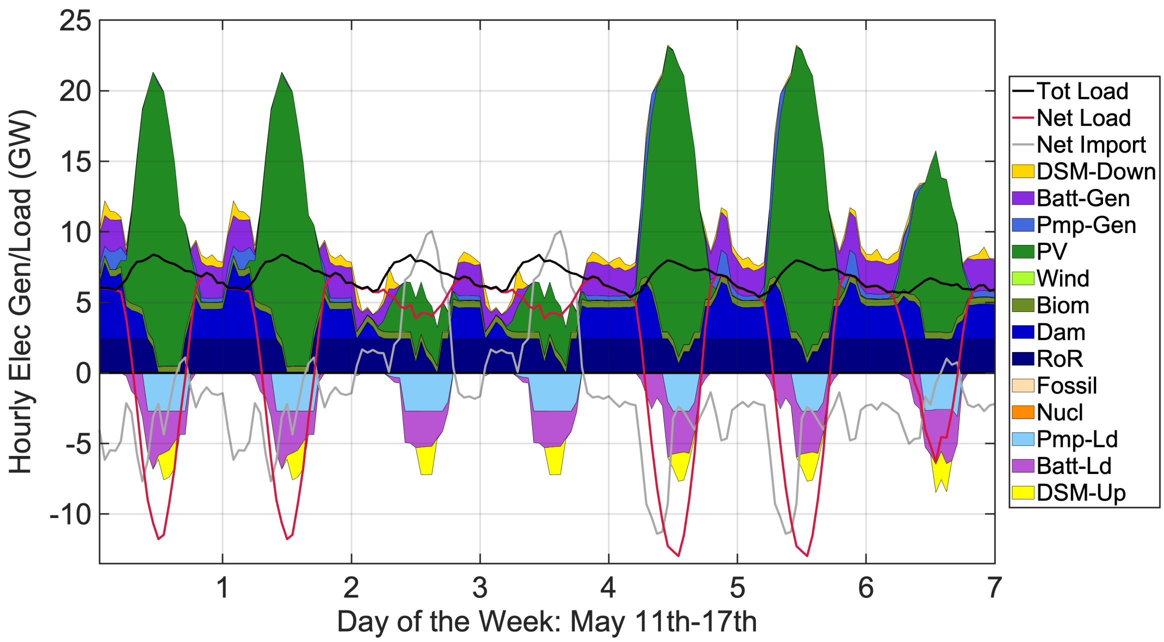


(b) Nuclear 60 - May - 2030

Figure 24: Differences in the hourly generation by technology type over the May week in 2030 between the Baseline and Nuclear-60 scenarios. The presence of more nuclear capacity drives up exports.



(a) Baseline - May - 2050



(b) High Flexibility - May - 2050

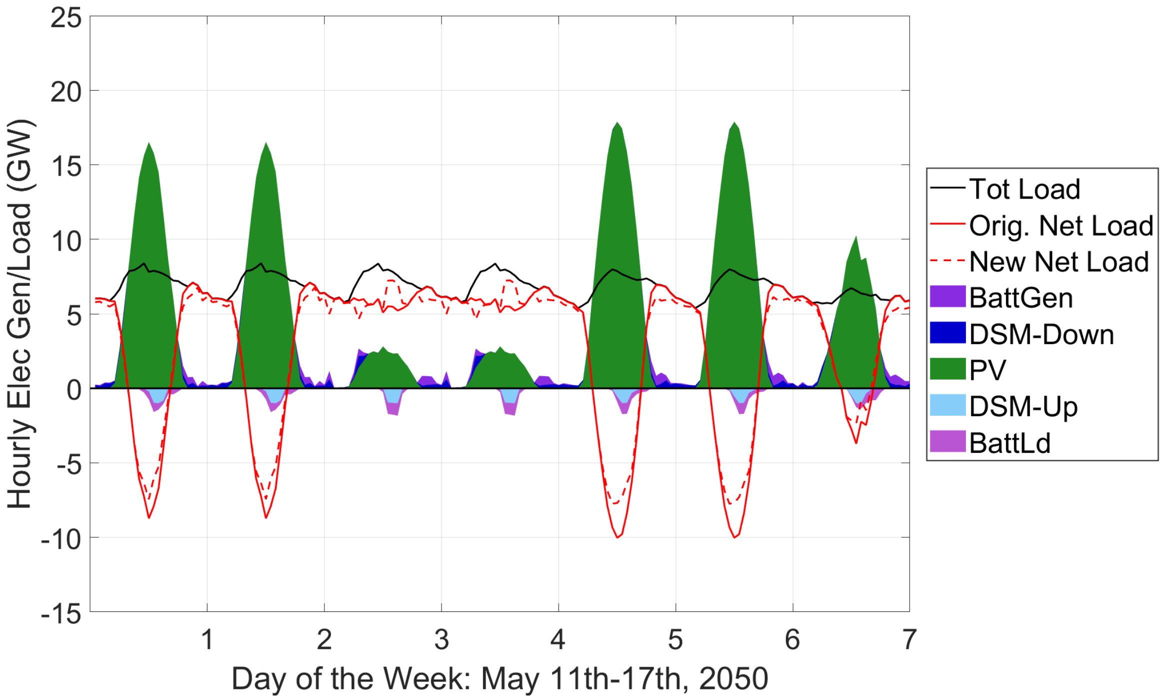
Figure 25: Differences in the hourly generation by technology type over the May week in 2050 between the Baseline and High-Flexibility scenarios. The presence of more flexible resources in the distribution system, in the form of BSS and DSM, reduces the use of imports and exports as one of the main sources of flexibility.

Distribution system perspective

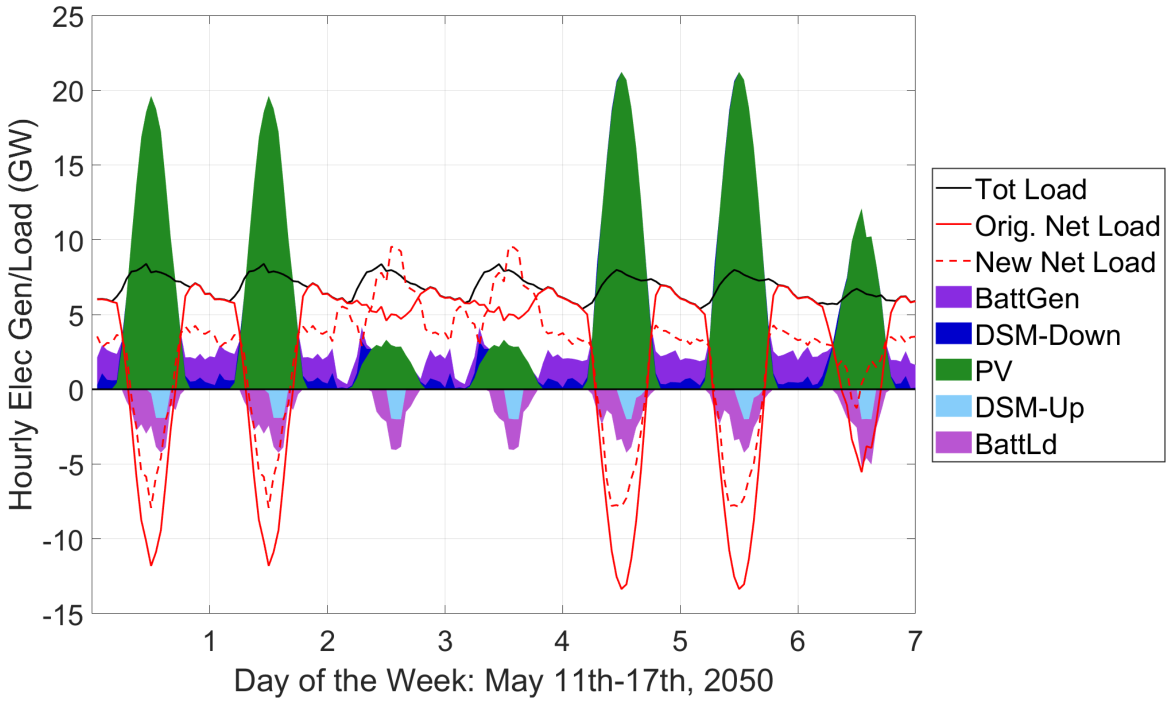
Figures 26 and 27 show the hourly generation, total load, ‘original’ net load, and ‘new’ net load of all distribution system resources modeled by DistIv for the Baseline and High-Flexibility scenarios of a May and a March week in 2050, respectively. The original net load is the total load minus PV generation, whereas the new net load also accounts for demand shifting from both BSS and DSM.

The figures show that in both scenarios the BSS and DSM shift demand from hours of low PV generation to hours of high PV generation to reduce the consumers’ supply costs by increasing their self-consumption rate. The PV-battery behaves similarly to the DSM, but it has the ability to store energy and therefore has higher flexibility. The PV self-consumption rate can be increased to more than 60% with the installation of PV-batteries. When there is a generation surplus of the PV system (i.e., PV generation is higher than the system demand), PV-batteries charge to absorb the excess energy then discharge during evening hours when no PV generation is available. In this way, the PV investor reduces his electricity bill by increasing his self-consumption rate. This behavior is especially prominent during the May week when the PV generation during the afternoon is much higher than the demand levels.

Moreover, it can be seen that for both scenarios the flexibility provided by DSM and PV-batteries helps to smooth the distribution system net load. This effect is strengthened in the High-Flexibility scenario where lower battery cost and higher DSM potential are modeled. Compared to the Baseline Scenario, more PV is installed in the High-Flexibility scenario since lower cost of battery units encourage the installation of PV-batteries and thus increases the self-consumption rate and profitability of investing in PV. Hence, even though the variation of the original net load is higher in the High-Flexibility scenario, thanks to the additional flexibility provided by the DSM and PV-batteries, the resulting new net load is even smoother than the one in the Baseline scenario.

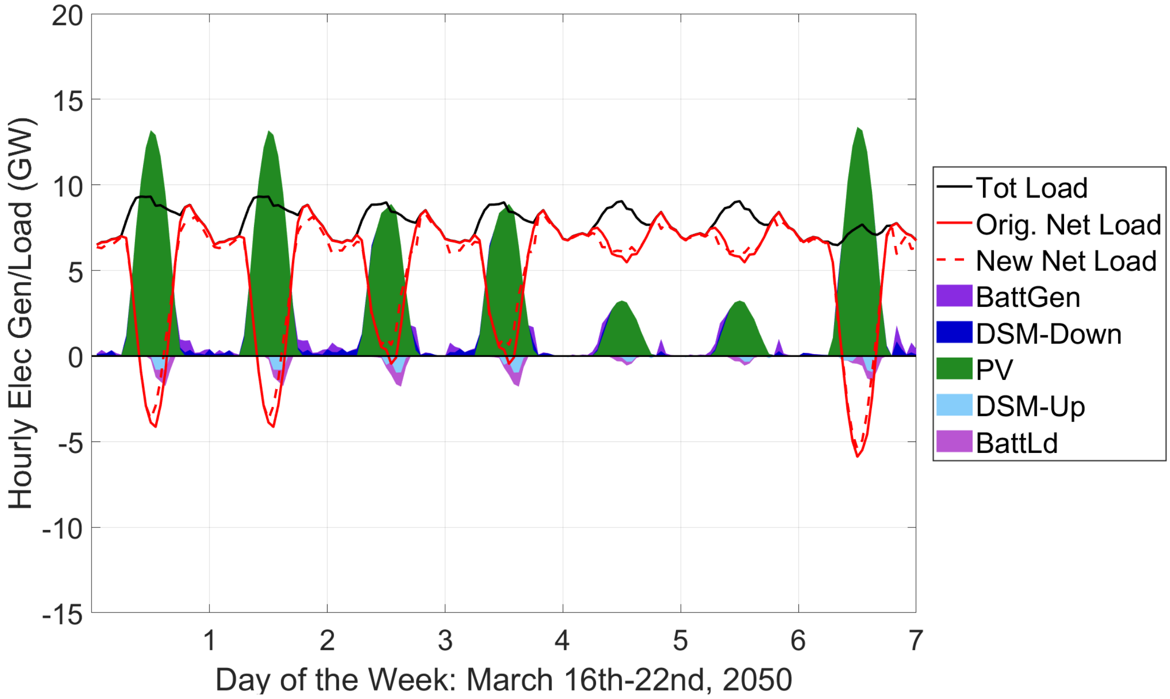


(a) Baseline - May - 2050

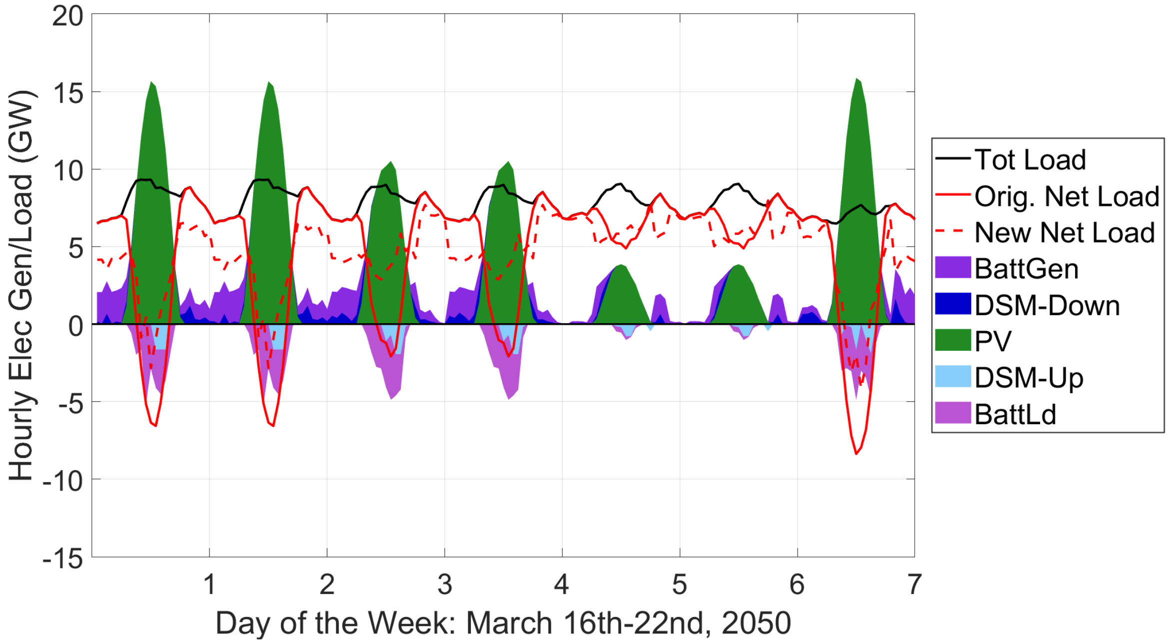


(b) High Flexibility - May - 2050

Figure 26: Flexibility provision by DistIv for a May week in 2050.



(a) Baseline - March - 2050



(b) High Flexibility - March - 2050

Figure 27: Flexibility provision by DistIv for a March week in 2050.

4.3.3 Sub-hourly

To present the results for the supply of flexibility on the sub-hourly timescales, results will first be presented that account for the need to supply increased reserve requirements to cover the added uncertainties introduced to the supply/demand balance (**Reserve procurement**). A second section will focus on the short-term response of the transmission network and reserves to handle the possible cascading impacts of component failures (**Grid reliability**).

Reserve procurement

Within Nexus-e, several modules represent the procurement of reserves, which determine the source of the required flexibility supply among the various generators available and allowed to provide reserves. These reserved capacities are held on standby, ready to compensate for sub-hourly effects of unit outages, load variability, and short-term forecast errors. The results for reserve requirements, shown in Table 9 of Section 4.2.3, illustrate that as more weather-dependent RES resources are integrated, the tertiary requirements increase from year-to-year. Overall, the increases in tertiary requirements are noticeable, adding up to 250 MW to the upward or downward reserves by 2050 compared to the Base tertiary requirements (which are 227 MW and 442 MW for upward and downward, respectively).

One question this assessment aims to answer is: are new dispatchable capacities needed in Switzerland to supply the necessary reserves to cover RES integration targets? This question is important to consider since reserve capacities cannot currently be procured from generators outside Switzerland[25]. Considering the magnitude of the required secondary and tertiary reserve capacities in 2050 as shown in Table 9 (total upward maximum of 842 MW and total downward maximum of 1071 MW in the High-Flexibility scenario, shown in Table 9) compared to the installed capacities of dispatchable generators that currently exist and remain until 2050 (nearly 8000 MW of hydro dam, over 4500 MW of pumped-hydro, 230 MW of biomass, and another 190 MW of other conventional units), the hypothesis is that these existing dispatchable capacities are more than enough to supply the extra reserves. Indeed, the simulation results confirm this expectation since the only new dispatchable capacities are the new biomass units, but these units are built based on their favorable economics in 2020. Furthermore, in 2020 the added reserves are less than 30 MW. Since no other dispatchable capacities are built, it is evident that the existing Swiss dispatchable generators are able to supply the additional flexibility necessary to cope with the forecast uncertainty of over 30 GW of added PV investments.

One additional issue that arose related to the reserve supply is that after the nuclear phase-out, the amount of generation scheduled under long-term contracts will likely reduce, which could impact the availability of downward reserve capacities. Since the reserve market clears one week ahead, the day ahead schedules of generators are not set at that point in time. So, each balancing group is limited in offering downward reserves based on the generators they already know will be operating under their long-term contracts and also based on the generators they expect to be dispatched in the day-ahead market. However, offering downward reserves with capacities that are expected to be cleared in the day-ahead comes with the risk that these units will not actually be cleared. So, the removal of baseload nuclear units without replacing them with other capacities that tend to be scheduled under long-term contracts could eventually reduce the offers in the downward reserve markets to a detrimental point. However, since the market is based on balancing group offers and not individual generator offers, this issue should be less critical. Indeed in both the CentIv and eMark simulation results, all downward reserves are supplied; but this issue is a potential problem based on the weekly timing of the reserve products and should not be ignored.

[25] With the exception of primary reserve, which the Swiss market currently allows generators in France, Germany, and Austria to supply [54]. However, in Nexus-e we take a more conservative approach and assume primary reserve must also be provided by Swiss generators

Grid reliability

This section answers two questions with respect to the security of the supply of the future Swiss electricity system. First, is the Swiss electricity grid prepared for the future power generation? Second, which are the needed grid expansions?

The power grid analyses are performed within the Security loop, which comprises the Cascades module that is interfaced with the eMark module. To assess the system security, the Cascades module uses the risk curve[26], which represents the complementary cumulative distribution function (CCDF), or exceedance probability of the DNS. The risk curve serves as an indicator of the risk of systemic failures in the electrical power grid. For this project, we use the risk curve of the 2015 Swiss power grid as a reference risk curve, which allows us to assess changes in the risk of systemic failures in future scenario-years. We derive the risk curves for the reference- and scenario-years by using stochastic sampling of the contingency sets[27] and loading conditions (in total 36000 simulated contingency events)[28].

Figure 28 shows how the risk of systemic failures evolves through the scenario-years in the Baseline scenario. The risk plots for the Nuclear-60, and High-Flexibility scenarios are similar, and are shown in Figures 40 and 41 in Appendix E. Each figure shows the risk of systemic failures in the 2015 Swiss grid (black curves), in the scenario-years without transmission system upgrades (red curves), and in the scenario-years with transmission system upgrades (green curves). In all future scenarios and scenario-years, the risk of systemic failures is higher than the 2015 reference year, when no transmission system updates are made, i.e., in all cases, the number of DNS events and the intensity of DNS events increases. However, the proposed transmission systems upgrades [29] are able to mitigate the increased systemic risks to the level of the 2015 reference year. In 2020, in all scenarios, although the overall risk of systemic failures after the expansion is reduced to the 2015 level, there are low probability events with higher DNS that are still remaining. This is because the transmission expansion planing model looks at the overall risk and not the individual events in the risk curve when making the decision of whether to make a gird expansion. Furthermore, we can observe that in the 2050 High-Flexibility scenario (Figure 41 in Appendix E), after the expansion, there are more DNS events in comparison to the 2015 reference year, nevertheless these events are very small (smaller than 1 kW).

The main difference between the 2015 reference year and the future years is that the stable baseload units are replaced by the variable PV. Thus, during days with high solar irradiation in Switzerland, PV power generation exceeds domestic demands and even adds to the export (as we can see in Section 4.2). These changes affect the system operations, including the utilization of the flexible generators, the nodal power injections and thus the power flows. One example of how the installation of PV may affect the system security is given in Section 4.2.3. Furthermore, the change in the net load and the large increase in imports and exports affect the utilization of the grid capacities. In occasions with these high imports and exports, the interconnectors and some of the internal Swiss lines and transformers are loaded more then before (i.e., the 2015 reference year). Therefore, if contingencies occur in such scenarios the likelihood of cascades with DNS as consequence increases.

Figure 29 visualizes the distribution of the average loading of each line/transformer in the grid for all scenario-years in the Baseline scenario, in comparison with the 2015 reference year. The average loading of lines/transformers is calculated from the power flows in each component at each hour for a scenario-year. The power flows are calculated using the AC formulation and the market dispatch for each hour of the corresponding scenario-year. The figure shows that the median of the average

[26] The risk curve gives the exceedance probability of observing DNS (blackout intensity), larger than the value reported on the x-axis.

[27] A single or multiple line/transformer failures, modeled stochastically (Monte Carlo process).

[28] In a previous study, we have performed sensitivity analyses that show that the selected amount of simulations is sufficient for systems with this size.

[29] We use Swissgrid transmission system data, including planned line upgrades until 2025 (see Section 2.5.1).

loading of lines/transformers decreases, especially in 2030. However, there are more extreme average loadings (above 100% of the rated power) in the future years that are causing an additional burden to grid operations. The reason for loadings larger than 100% are: 1) the market dispatch does not account for the internal Swiss line limitations and we do not perform redispatch; 2) the aggregated border nodes and surrounding country networks adds restrictions to how flows split across the Swiss border lines going to each neighbor. The distributions of the average loading of lines/transformers in the Nuclear-60 and the High-Flexibility scenarios are similar, and are shown in Figures 42 and 43 in Appendix E.

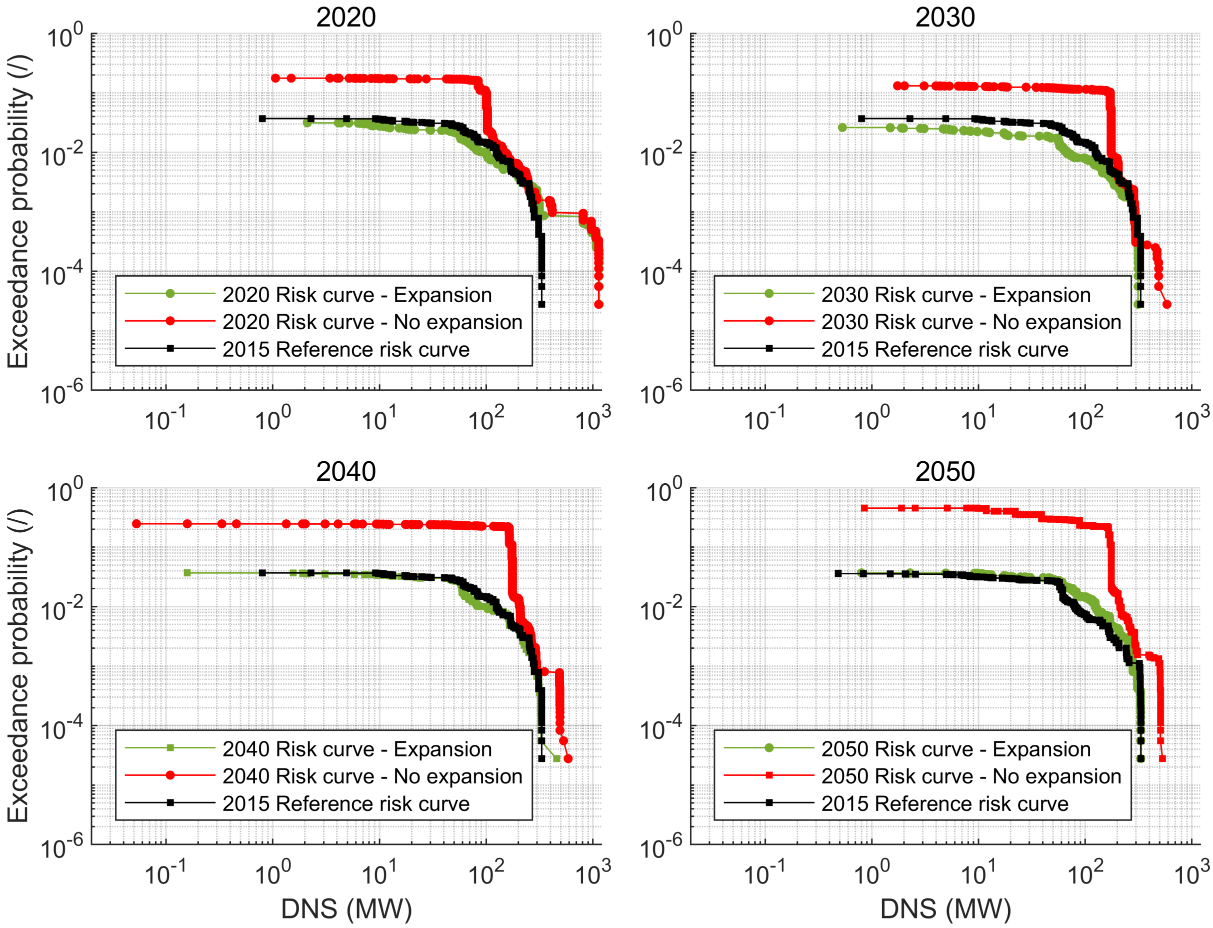


Figure 28: Risk curves for the Baseline scenario: reference (black), scenario-year without expansion (red), scenario-year with expansion (green).

To bring system security in the future scenario-years to a similar level as in 2015, the transmission system expansion planning of Nexus-e proposes grid line upgrades. Figure 30 shows the proposed expansion of the transmission system, which amounts at retrofitting an existing interconnector with Italy (CH AllAcqua 220 - Italy[30]). This line is proposed for upgrade across all scenario-years in all scenarios, i.e., the line is doubled, with the exception of scenario-year 2050 in the Baseline and Nuclear-60 scenarios in which the line is tripled. It is important to note that in the scenario-year 2050 in the High-Flexibility scenario this line is only doubled due to the lower risk of systemic failures compared to the Baseline and Nuclear-60 scenarios. To identify grid line upgrades, the Cascades module as indicators uses the impact of line failures on the DNS and the frequency of line overloads[31]. Before a decision is made, the module

[30]We use a grid simplification such that all interconnectors from Switzerland to a neighboring country ends in a single node at the respective country.

[31]The detailed description of the Cascades module and the transmission system expansion planning method is given in the

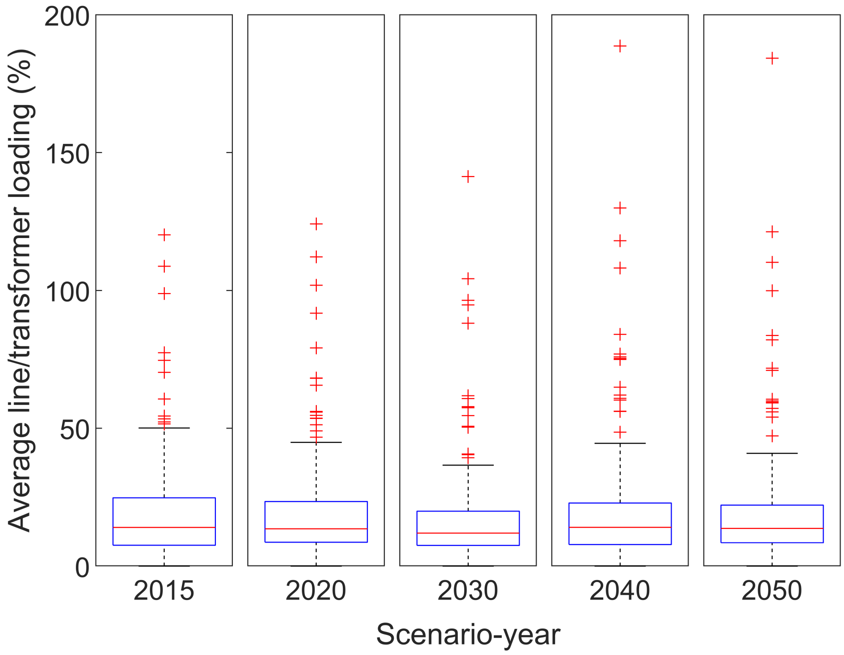


Figure 29: The distribution of the average line/transformer loadings in the reference- and scenario-years for the Baseline scenario. The blue box denotes the interquartile range of the data (25th to 75th percentile); the red line denotes the median (50th percentile); the red crosses denote the outliers; and the whiskers denote the most extreme points, not considering the outliers.

compares the results using both indicators and then selects the one offering the best risk improvement. The proposed upgrade, i.e., CH AllAcqua 220 - Italy, is identified using the frequency of line overload indicator. This means that the line is not selected because of its direct impact on the DNS, but because of its effect on the development of cascades in the grid, which can result in DNS subsequently. Due to its lower capacity, this line is frequently overloaded when a failure occurs in another interconnector with Italy or a line in the south of Switzerland. The overload in the selected line often results in cascades that reduce the transmission capacity, which in some occasions, cause voltage violations/instabilities in the South of Switzerland. Further investigation would be needed to understand the effects of these failures on the voltage stability.

Figure 31 illustrates the change in risk of systemic failures in the future scenario-years (without expansion planning) in comparison to the 2015 reference year. Each point in the figure represents the distance between the 2015 reference risk curve and the scenario-year risk curve. The results show that, before the transmission system upgrades are introduced, the risk of systemic failures in all scenario-years for all scenarios is higher than in the reference year. Moreover, the Baseline scenario and the Nuclear-60 scenarios have a similar rate of risk increase, while the High-Flexibility scenario shows a higher increase in 2030 but a lower risk increase in 2040 and 2050. In 2030, there is more PV installed (no PV-batteries) in the High-Flexibility scenario compared to the Baseline and Nuclear-60 scenarios. However, the main difference among the scenarios is the significantly larger amount of PV-batteries installed in 2040 and 2050 in the High-Flexibility scenario, as well as the higher potential for DSM. It can be concluded that the batteries and the DSM improve the system flexibility and, thus, have a positive impact on system security.

Figure 32 shows the use of positive and negative generation reserves that have been activated during systemic failures for all scenario-years in the Baseline and the High-Flexibility scenario without

Cascades module documentation.

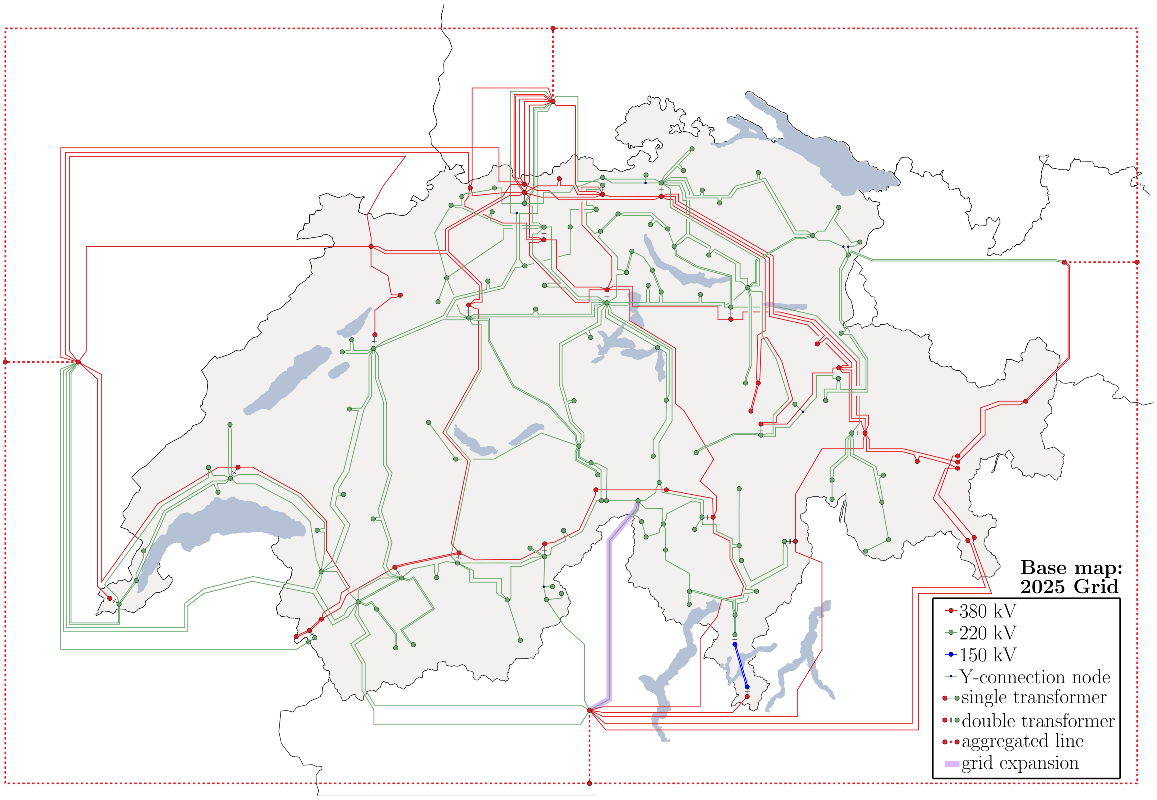


Figure 30: The proposed grid expansion needed to achieve a similar level of security as the 2015 reference year requires upgrades to an interconnector with Italy.

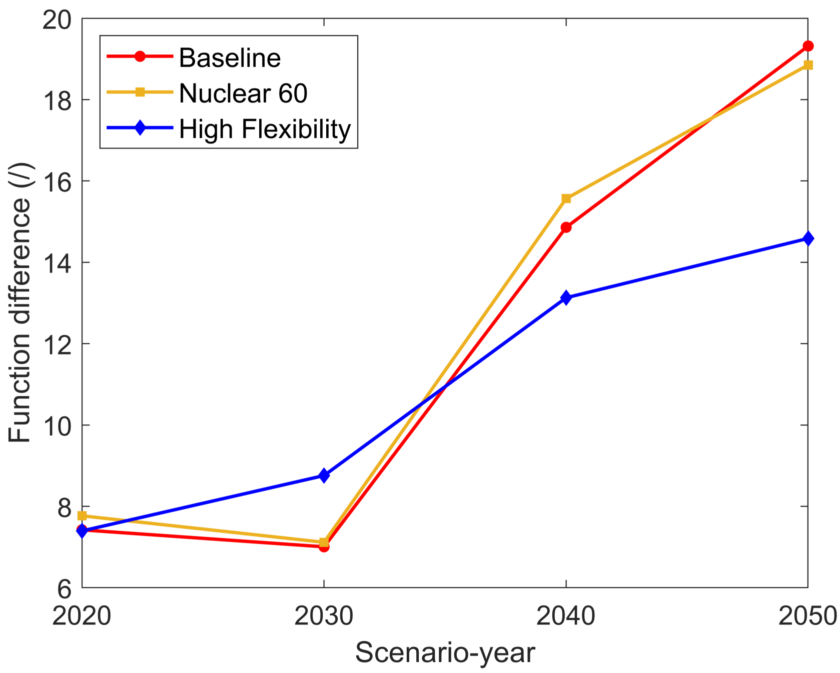


Figure 31: The change of risk of systemic failures in each scenario-year and scenarios - without expansion planning.

expansion planning. In both scenarios, the utilization of positive and negative generation reserves in all scenario-years increases compared to the 2015 reference year. The system uses these reserves to balance the frequency instabilities after a loss of generator or load, which can occur after the initial contingencies and subsequent failures in the power grid. In 2030, in comparison to 2020, there is a significant reduction in stable nuclear generation and a significant increase in variable PV generation, hence the increased need for flexibility. In the same period, we can observe that there is a significant increase in the utilization of the generation reserves. Furthermore, Figure 29 shows that there is an increase in the extreme loadings of the grid components. The extreme loadings in combination with contingencies increase the likelihood of cascades that disconnect nodes with generators and loads, thus increasing the need for utilization of reserves[32]. Moreover, the High-Flexibility scenario uses less positive and negative reserves for all scenario years. These results also show that the increased amount of PV-batteries and DSM potential in 2050 reduce the need for generation reserves on the transmission system level.

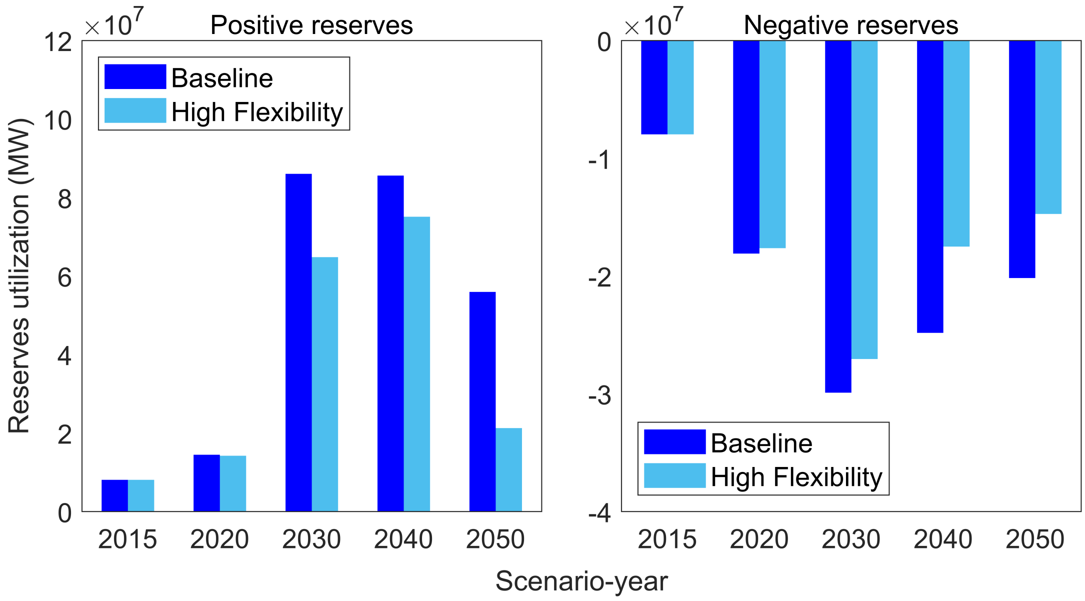


Figure 32: Total utilization of available positive and negative reserves for the Baseline and High-Flexibility scenarios - without expansion planning.

The analyses show that in general the Swiss electricity grid can take on the challenges that the future power generation transformation brings. Furthermore, specific upgrades, i.e., power lines in the transmission system, can maintain the system security at a level similar to the 2015 reference year.

[32]The utilization of the generation reserves is affected by the selected contingencies and loading conditions.

4.4 Comments on economic and environmental impacts

This section briefly compares the economic and environmental impacts across scenarios with a focus on the GDP, the gross investment, and the CO_2 emissions of Switzerland. Note that since this project focuses on the flexibility of the Swiss electric power system, our varying scenario inputs (i.e., the runtime of nuclear power plants, battery cost development, DSM potential) are not expected to introduce substantial economic and environmental differences.

We calculate the percentage differences in GDP, gross investment, and CO_2 emissions (national and economy wide) under the Nuclear-60 and High-Flexibility scenarios compared to the Baseline scenario for each year, and averaged it through 2020-2050. The results are shown in Table 10. For GDP, the difference is less than 0.01%, which is negligible compared to the annual GDP growth of Switzerland (e.g., the GDP growth of Switzerland from 2017 to 2018 was 2.8%[33]). Similarly, the difference of the gross investment is also minor across scenarios, despite the strong investment into batteries in 2050 in the High-Flexibility scenario. This is because the annualized investment costs are only a fraction of total investments in Switzerland. Furthermore, there is a *crowding-out effect*, which describes the phenomenon that investments into one part of the market reduces the investments into the remainder of the market. For the CO_2 emissions, the difference is also minor, indicating that different scenario-inputs do not affect CO_2 emissions substantially. The slight change in electricity net import (Figure 5) does not bring a significant change in the national CO_2 emission.

Table 10: Percentage changes in GDP, gross investment, and CO_2 emissions compared to the Baseline scenario.

	GDP	**Investment**	**CO_2 emissions**
Nuclear 60	-0.007%	0.020%	0.149%
High Flexibility	-0.001%	-0.012%	-0.080%

[33] https://www.bfs.admin.ch/bfs/en/home/statistics/national-economy/national-accounts/gross-domestic-product.html

5 Conclusion

The Swiss Energy Strategy 2050 envisions a future Swiss power system that is characterized by the integration of high shares of renewables and distributed energy resources, the nuclear phase-out, the increase of energy efficiency, the interplay with the energy transitions in other European countries, and a consistent level of system security and resilience. One key challenge to achieve the envisioned power system is the increasing variability and uncertainty of power supplied by renewable energy sources, which need to be matched with higher flexibility across a range of timescales. In order to study the future development of the Swiss electricity system as well as its need and supply of flexibility, we developed the Integrated Energy Systems Modeling Platform (Nexus-e), which comprehensively represents the Swiss energy-economic system and aims to identify the cost-optimal investment in and operations of centralized and distributed energy resources, taking into account their socio-economic impact and changes in the security of supply. In this report, using the Nexus-e platform, we present results from three scenarios (Baseline, Nuclear 60, and High Flexibility) and answer the following questions:

What are the potential pathways for the future Swiss electricity system?

> In Section 4.1, we showed that new PV installations replace nuclear capacity to a large extent, with some investments in biomass and PV-batteries (in the High-Flexibility scenario, PV-battery investment is substantial, achieving almost 10 GW by 2050), but no investment in grid-batteries and wind power. Between 2030 and 2040, the phase-out of investment subsidies makes investments in PV less attractive, resulting in a stagnating PV capacity. Decreasing PV prices and the uptake of PV-batteries that improve the economic viability of self-consumption, spur PV installations, resulting in 25.4 - 31.1 GW of PV capacity by 2050. By 2050, PV is responsible for the largest share (i.e., 32.6-35.5%) of electricity consumption, followed by hydro dam (26.0-28.3%) and hydro RoR (15.9-17.4%). Additionally, as nuclear gets phased out, imports become a larger contributor to the supply of electricity in Switzerland with up to 5.7% in 2050. Critical, however, is the time between 2030-2040, when the stagnating PV capacity cannot substitute nuclear phase-out fully, resulting in substantially higher net imports of up to 16.5% of the annual demand. Yet, RES targets are achieved in all scenarios and years, even in 2040. Please note that all results presented in this report are subject to pronounced uncertainties and assumptions. Therefore, we do not claim that the current legislative and regulatory framework is sufficient to achieve the RES targets.

What is the need for flexibility in the projected Swiss electricity system?

> In Section 4.2, we highlighted the increasing need for flexibility across a range of timescales. First, the seasonality of the net load increases in all future years and is more pronounced in 2050 as the PV penetration level is higher. This trend indicates the need for greater seasonal flexibility that could impact the operation of hydro storages or other generators as well as the pattern of imports and exports. Second, the increasingly dynamic pattern of the net load on an hourly and daily basis emphasizes the need for fast ramping flexible capacities such as hydro dams and gas-fired generators along with storages and load shifting units like pumped hydro, BSS, or DSM. Third, tertiary reserve requirements increase from year-to-year as new PV investments are added. Overall, the increases in tertiary requirements are noticeable, increasing upward and downward reserves by almost 100% and 50%, respectively, by 2050. Fourth, short-term system stability is jeopardized by the increased share of non-dispatchable units.

Who provides the required flexibility?

In Section 4.3, we outlined how the need for flexibility is met. We showed that net imports play a crucial role for addressing the increasing requirement for seasonal flexibility. By 2050, the monthly net imports follow closely the seasonal net load pattern. Also, the seasonality of the hydro dam generation becomes more pronounced by 2050, making hydro dams essential for providing seasonal flexibility. Extending the nuclear lifetime to 60 years allows Switzerland to be less import-dependent in 2030 and 2040, particularly in winter months. Besides providing seasonal flexibility, Swiss generators also have to adjust their operation to account for the increasingly rapid changes in the hourly net load. Mostly imports and exports as well as hydro dams, but also hydro pumps, hydro RoRs, PV-batteries, DSM react rapidly to help provide the necessary supply along with more frequent curtailments of non-dispatchable units in future years. However, higher shares of flexible PV-batteries and DSM resources successfully smooth the hourly net load and thus reduce the reliance on imports/exports for hourly flexibility. Furthermore, the existing Swiss dispatchable capacities are expected to be able to supply the reserves that are required to cope with the sub-hourly forecast uncertainty of PV investments in all scenarios. In all projections for the future Swiss power systems, the risk of systemic failures initially increases but can be addressed by upgrading one transmission line. PV-batteries and DSM can even further reduce such risk and strengthen system security.

What are the macroeconomic and environmental impacts of the future Swiss electricity system?

In Section 4.4, we also assessed the macroeconomic and environmental impacts of the future Swiss electricity system. However, the differences between the scenarios for GDP, gross investments, and carbon emissions are below 0.02%. Therefore, we conclude that, as expected, our varying scenario inputs (i.e., the runtime of nuclear power plants, battery cost development, DSM potential) do not introduce substantial macroeconomic and environmental differences.

Obtaining these thorough results is enabled by conducting holistic simulations of the Swiss electricity system with the Nexus-e platform. The platform combines bottom-up and top-down energy modeling approaches and thus represents a broader scope of the energy-economic system at a regional and national scale with a high time resolution. Its modularity and well-defined interfaces allow us to connect various domains (e.g., electrical engineering, power markets, economics), network levels (centralized and distributed), and timescales (from sub-hourly to yearly) into one integrated platform. Thus, we capture the interdependencies of a wide range of components, sectors and layers of the entire Swiss electricity system. With such a comprehensive representation, we are able to show that Switzerland could achieve both the nuclear phase-out and RES targets while supplying sufficient flexibility and maintaining system security.

The Nexus-e platform has several limitations of which we highlight a few in the following. First, we only consider the power system and the electricity grid, thus neglecting the increasing coupling with the heating system and the ongoing electrification of the building and transport sectors. As future research, we plan to include a bottom-up representation of buildings' electricity and heating demand, including a model of the natural gas grid. We also aim to better represent electrification of the building and mobility sectors by utilizing realistic load patterns that evolve from year to year and differ from node to node. These enhancements will also expand the scope of Nexus-e across multiple energy sectors for complimentary operation and will enable assessments that account for the possibility to implement these new, often distributed, infrastructures in grid-friendly ways. Second, the representation of Switzerland's surrounding countries is highly aggregated. However, increasing the level of detail of the European power system causes higher computational complexity and longer simulation time. Therefore, in a next step, we need to find a balance between the level of detail and the simulation time, for example, by using a common level of aggregation for all European countries in the ENTSO-E. Third, we currently only improve the system security by updating the transmission grid. In the future, we plan to enhance this process to include additional capabilities for achieving the desired system security, such as: adjusting the market dispatch using risk-based indices, and introducing a redispatch procedure after the market-clearing simulation. Fourth, we independently perform the generation and transmission network expansion planning decisions. In the future, Nexus-e could instead include coordinated generation and transmission expansion planning in order to make more optimal decisions. Fifth, we model investment behavior using a cost-minimization objective and assuming one central investor. A future version of Nexus-e should account for a heterogeneous investor population, including, for example, varying risk profiles and cost-unrelated objectives such as peer-effects. These enhancements toward a distributed consumer perspective would enable assessments on the impacts of changes to the network fees, distributed PV injection tariff, and consumer time-of-use pricing on the integration of distributed capacities and on the need for central investments. In addition, all Nexus-e modules have individual limitations (see individual model reports). Therefore, in the next phase, we plan to perform numerous improvements and extensions of all Nexus-e modules. For example, CentIv does not represent the full hydrological network and connections between reservoirs and hydro generators. Another example is the simplification of the distribution grid through aggregating electricity demand and generation on cantonal level in DistIv. Besides addressing these limitations, we also plan to design and create new scenarios. One example is the evaluation of future Swiss power market designs and regulations such as enabling local markets.

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Appendices

A Methodology for quantifying additional reserves needed from RES investments

The modules in Nexus-e include a detailed representation of positive and negative secondary and tertiary balancing markets in Switzerland. These include both the country wide demand for balancing capacity (included in CentIv and eMark) as well as the deployment of balancing energy in response to contingencies (in Cascades). To account for the need for larger amounts of balance reserves, Nexus-e builds on the methodology used previously in the project AFEM (Assessing Future Electricity Markets) [6]. The description of this methodology below is drawn from previous documentation and updated according the implementation within Nexus-e.

The current methodology employed by Swissgrid to quantify the amount of secondary and tertiary reserves needed uses a robust probabilistic approach [53]. This work assumes that the amounts currently being procured approximately represent the amount of reserves needed to cover for conventional issues (load variability and generator outages). During each hour of the year, Swissgrid procures on average 379 MW of Secondary reserves (upward and downward) along with 227 MW of Tertiary upward and 442 MW of Tertiary downward reserves [33]. These amounts are set as the base reserve requirement, (B^{+0}_{mcyt}) for upward and (B^{-0}_{mcyt}) for negative, in MW, for a given balancing market (m) in region (c) in year (y) and hour (t) and combined using a geometric sum (eqs. (1) and (2)) with the appropriate contribution to from wind, (B^{+w}_{mcyt}) or (B^{-w}_{mcyt}), and PV, (B^{+s}_{mcyt}) or (B^{-s}_{mcyt}), in MW, to cover their uncertainties and to quantify the total positive (Bal^{+}_{mcyt}) and negative (Bal^{-}_{mcyt}) reserve requirements in MW .

$$Bal^{+}_{mcyt} = \sqrt{B^{+0}_{mcyt} + B^{+w}_{mcyt} + B^{+s}_{mcyt}} \qquad \forall m, c, y, t \tag{1}$$

$$Bal^{-}_{mcyt} = \sqrt{B^{-0}_{mcyt} + B^{-w}_{mcyt} + B^{-s}_{mcyt}} \qquad \forall m, c, y, t \tag{2}$$

The method that is used to quantify the additional amount of secondary and tertiary reserves needed to cover for the added uncertainty of any new wind or PV capacity installed, is based on statistical calculations and methods of forecasting wind and PV generation. To quantify the contributions that wind and PV uncertainties would have, the forecast errors are calculated for every 10-minutes using time-series data for wind speed and PV irradiance in Switzerland that were provided by IDAWEB [47]. Using the Swissgrid confidence threshold of 99.9%, the reserve contribution factors from eqs. (1) and (2) are calculated from the wind and PV forecast errors and combined with the base reserve requirements to yield the total system reserve requirements.

Wind and solar energy both add to the uncertainty that operators must overcome because these resources rely on wind speeds and solar irradiances that cannot be perfectly predicted. For this work, large amounts of renewable energy will therefore imply the need for an increased degree of flexibility in terms of system-wide energy production capability to account for possible fluctuations in RES generation. This will entail that a higher operating margin could foreseeable be required in terms of primary, secondary, and tertiary operating reserves.

While the utilization of operating reserves is universally employed among power systems, there is no common methodology for dimensioning the amount of reserves that should be procured. Across the world, power systems employ different unique procedures to quantify their desired reserve requirements. Often, these procedures are heuristically determined through past experiences, are static over long time periods, and have been in place for many years or even decades. While these procedures may be efficient for traditional sources of imbalance like generator outages, whose probability of being forced offline does not generally change over time, they lack the ability to use updated system information to improve the efficiency of the reserve requirement, which could more effectively compensate for real-time load or RES generation conditions.

The selected reserve methodologies for quantifying operating reserves necessary for added wind and PV power represent some of the most recent and advanced literature [49, 50, 51, 52]. The most relevant literature surveyed was from the various renewable integration studies conducted by researchers and electricity markets around the world [55, 56, 48, 57]. We feel that we have chosen a methodology that advances what is seen in all operating reserve markets today and is in line with the most state-of-the-art research-based methods. The selected methodology will be able to quantify the necessary flexibility required to compensate for the additional uncertainty of wind and solar power and better enable a reliable and stable electric grid.

For wind power, the reserve procedure uses a synthetic forecast created assuming persistence of wind power production from one time period to the next (eq. (3)) where the forecasted power output ($\hat{q}^R_{r_w c_s (t+1)}$) of the renewable wind resource (r_w) in the Switzerland region (c_s) for the next time interval ($t+1$) is equal to the actual wind power output ($q^R_{r_w c_s t}$) at the current time interval (t). This type of persistence forecast, while computationally simple, has been shown to match more complex forecast methodologies for short-term forecast horizons of up to one hour ahead [48].

$$\hat{q}^R_{r_w c_s (t+1)} = q^R_{r_w c_s t} \qquad r_w \subset r, \quad c_s \subset c, \quad \forall t \tag{3}$$

For PV, the reserve procedure is enhanced to include the impacts of the known daily behavior of the sun. Instead of assuming the persistence of solar power output, the method uses a synthetic forecast created assuming persistence of cloudiness and accounts for the change in the clear sky solar irradiance from one time period to the next. To begin, the Solar Power Index (SPI) at each time step (t), is defined in eq. (4) as the ratio between the actual solar power output ($q^R_{r_s c_s t}$) and the clear sky solar power output ($\tilde{q}^R_{r_s c_s t}$) of the renewable solar resource (r_s) in the Switzerland region (c_s) to represent the current cloudiness level.

$$SPI_t = \frac{q^R_{r_s c_s t}}{\tilde{q}^R_{r_s c_s t}} \qquad r_s \subset r, \quad c_s \subset c, \quad \forall t \tag{4}$$

Next, the clear sky solar power ramp (($\Delta\tilde{q}^R_{r_s c_s (t+1)}$)) is defined as the difference between the clear sky solar power outputs ($\tilde{q}^R_{r_s c_s}$) from one time interval (t) to the next ($t+1$), as shown in eq. (5), and is used to account for the known movement of the sun within the forecast.

$$\Delta\tilde{q}^R_{r_s c_s (t+1)} = \tilde{q}^R_{r_s c_s (t+1)} - \tilde{q}^R_{r_s c_s t} \qquad r_s \subset r, \quad c_s \subset c, \quad \forall t \tag{5}$$

Combining these to the estimate the forecasted solar power output ($\hat{q}^R_{r_s c_s (t+1)}$) for the next time interval ($t+1$), the actual solar power output ($q^R_{r_s c_s t}$) at the current time interval (t) is added to the upcoming clear sky solar power ramp ($\Delta\tilde{q}^R_{r_s c_s (t+1)}$) scaled by the cloudiness index (SPI_t) (eq. (6)).

$$\hat{q}^R_{r_s c_s (t+1)} = q^R_{r_s c_s t} + SPI_t * \Delta\tilde{q}^R_{r_s c_s (t+1)} \qquad r_s \subset r, \quad c_s \subset c, \quad \forall t \tag{6}$$

Rearranging yields a simplified version, shown in eq. (7), that shows this method is equivalent to assuming the forecasted solar power output for the next time interval is equal to the actual solar output in the current time interval multiplied by the ratio of the clear sky solar output ($\tilde{q}^R_{r_s c_s}$) between the two time intervals.

$$\hat{q}^R_{r_s c_s(t+1)} = q^R_{r_s c_s t} * \frac{\tilde{q}^R_{r_s c_s(t+1)}}{\tilde{q}^R_{r_s c_s t}} \qquad r_s \subset r, \quad c_s \subset c, \quad \forall t \tag{7}$$

For this work, the forecast equation is simplified further by assuming that the ratio of the clear sky solar power output ($\tilde{q}^R_{r_s c_s}$) between the two time intervals is equal to the ratio of the clear sky global horizontal solar irradiance ($\tilde{I}^R_{r_s c_s}$) (eq. (8)) between the two time intervals. Substituting yields the final equation for the solar power forecast (eq. (9)).

$$\frac{\tilde{I}^R_{r_s c_s(t+1)}}{\tilde{I}^R_{r_s c_s t}} = \frac{\tilde{q}^R_{r_s c_s(t+1)}}{\tilde{q}^R_{r_s c_s t}} \qquad r_s \subset r, \quad c_s \subset c, \quad \forall t \tag{8}$$

$$\hat{q}^R_{r_s c_s(t+1)} = q^R_{r_s c_s t} * \frac{\tilde{I}^R_{r_s c_s(t+1)}}{\tilde{I}^R_{r_s c_s t}} \qquad r_s \subset r, \quad c_s \subset c, \quad \forall t \tag{9}$$

This last assumption takes advantage of the fact that the size of the PV panels does not change over time and therefore the ratio for a single unit area (i.e. 1 m2) would be the same as the ratio for all solar panels. While this method would yield more accurate forecasts if it used the tilt and orientation of every individual PV panel, assuming a per-unit-area ratio eliminates the computational complexity of creating a forecast for each individual panel. However, this assumption does ignore that the panel efficiency could change slightly between the two time intervals based on a change in panel temperature. But, we assume that as long as the time step is small (i.e. an hour or less), the change in panel temperature will be minor and therefore the change in panel efficiency will be minimal. Additionally, by assuming a horizontal surface, this simplification omits the slight change in the solar zenith angle from one time period to the next. Once again, because the time step is small, the change in solar zenith angle and its impact on the global irradiance should be minimal.

Before utilizing this solar forecast method, we first had to develop a mathematical way to calculate the clear sky global horizontal solar irradiance over the full year with a time step size equal to that of the forecast step size (as small as 10 minutes). Once again, we conducted a thorough literature review and identified several mathematical models for clear sky solar irradiance, including the Bird model [58] and Frouin model [59]. Both of these models calculate the global solar irradiance on a horizontal surface for a given zenith angle along with corrections for attenuation in the atmosphere due to scattering and absorptance. The Bird model was selected for this analysis because it provides the additional benefit of calculating global as well as direct and diffuse irradiance values. In addition, several models were considered for calculating the solar position (zenith angle, air mass, etc.) for any given global position and time of year including the methods of Spencer [60], Michalsky [61], and Meeus [62, 63]. The methodology from Meeus was selected for this work based on its balance between accuracy and complexity. Once combined, these models are able to estimate the solar irradiance at any location on earth over a one-year period using any user-defined time step.

Using the forecast equations for wind (eq. (3)) and PV (eq. (9)), the forecast errors are quantified for every 10-minute period over the year and the 99.9% confidence threshold is applied to calculate the wind and PV contribution factors included in eqs. (1) and (2). This process is applied to a multitude of wind and PV production profile derived from AFEM's Swiss renewable potential analysis, described in [6], to establish all contribution factors (i.e., wind (B^{+w}_{mcyt}) (B^{-w}_{mcyt}) and PV (B^{+s}_{mcyt}) (B^{-s}_{mcyt})) for these profiles. The results of this process provide the total upward and downward reserve necessary for multiple combinations of installed wind and PV capacities.

In a final step, we fit functions to the unique values of the resulting reserve requirements that will allow us to estimate the requirements for any value of installed wind and PV capacity. However, since the geometric sum in eqs. (1) and (2) is nonlinear, CentIv utilizes a simplified version of these functions to keep the investment model computationally tractable. Specifically, we assume a linear relation between reserve demand and the amount of installed renewable capacities:

$$Bal^{+}_{mcyt} = B^{+0}_{mcyt} + b^{+}_{wmcyt} CAP^{R}_{wcy} + b^{+}_{smcyt} CAP^{R}_{scy} \qquad \forall m, c, y, t \tag{10}$$

$$Bal^{-}_{mcyt} = B^{-0}_{mcyt} + b^{-}_{wmcyt} CAP^{R}_{wcy} + b^{-}_{smcyt} CAP^{R}_{scy} \qquad \forall m, c, y, t \tag{11}$$

where (B^{+0}_{mcyt}) and (B^{-0}_{mcyt}) are the same base demand, in MW, as in eqs. (1) and (2) for positive and negative balancing capacity. (b^{+}_{wmcyt}) and (b^{-}_{wmcyt}), in MW/MW$_w$, are the slope coefficients for all newly installed wind (w) capacity (i.e., MW of additional reserve per MW of new wind capacity) and (b^{+}_{smcyt}) and (b^{-}_{smcyt}), in MW/MW$_s$, are the slope coefficients for all newly installed solar (s) capacity. Therefore, the detailed methodology is used to quantify reserve demand for all types of reserve for all possible combinations of wind and solar power capacity.

B Additional information: sensitivity analysis of WACC

Cost of capital is defined as the expected rate of return that market participants require in order to attract funds to a particular investment [64]. The value of WACC varies over time and between different technologies, e.g. 0-10 kWp and 10-30 kWp PV units are mainly invested by households, who face lower WACC than investors of greater-sized PV units. In the reference scenario, we assume a constant 5% WACC for all four PV categories. More realistic would be to use different distributions of these parameters for each PV category, but this requires additional input data and increases the implementation overhead.

Figure 33 analyzes the effects of WACC on PV installations by comparing the reference case against a case with WACC equalling to 2.5%, 2.5%, 7.5% and 10% for 0-10 kWp, 10-30 kWp, 30-100 kWp and >100 kWp PV categories, respectively. It can be seen that increasing WACC decreases the profitability of PV investment as an increase in WACC means an increase in risks and a decrease in valuation. By differentiating the WACC that different groups of investors face, PV investments shift from larger-sized toward small-sized PV categories.

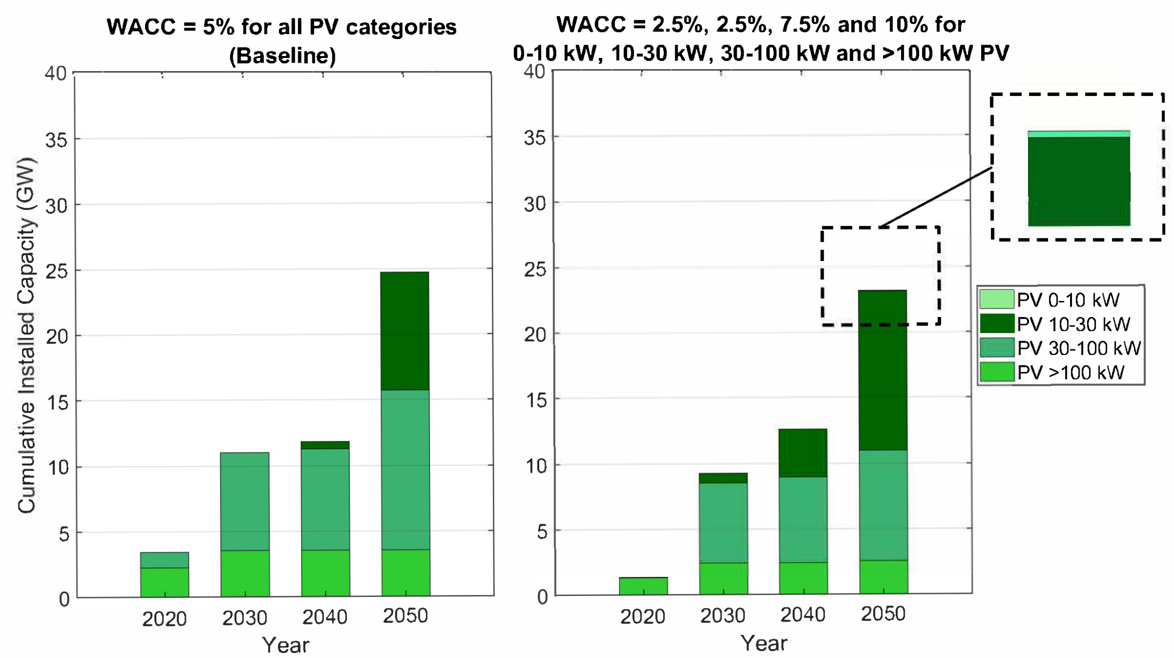


Figure 33: Effects of weighted average cost of capital.

C Additional information: input data of a low, moderate and high PV cost scenario

Table 11: A low, moderate and high cost scenario of PV investment and operational cost developments for years 2020-2050 as a percentage of the 2018 cost based on [36].

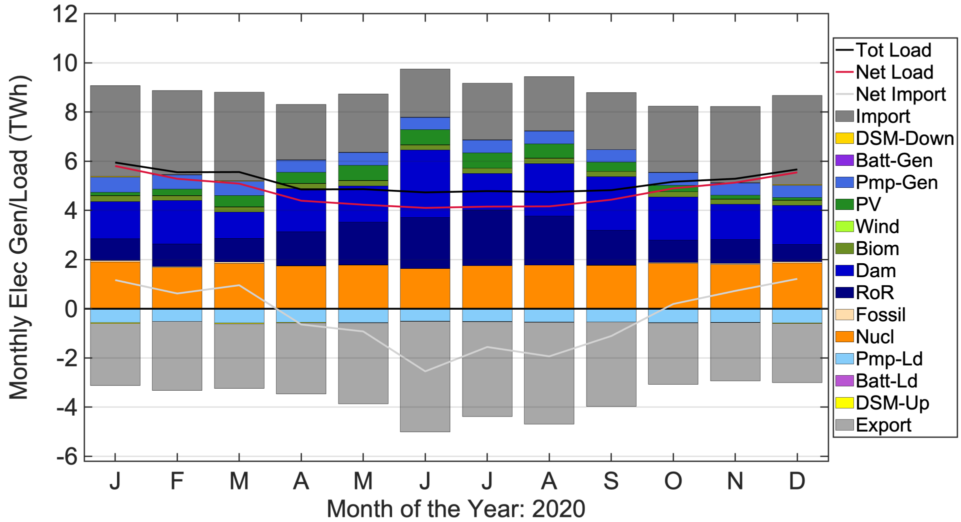
(a) Investment costs

Category	2018	2020			2030			2040			2050		
(kWp)	ref.	low	mod.	high	low	mod.	high	low	mod.	high	low	mod.	high
0-10	100%	81%	86%	96%	62%	71%	80%	51%	61%	71%	49%	57%	64%
10-30	100%	81%	87%	92%	62%	71%	81%	47%	57%	67%	36%	44%	51%
30-100	100%	78%	84%	90%	59%	69%	79%	46%	57%	68%	39%	48%	57%
>100	100%	75%	81%	88%	55%	66%	78%	44%	57%	69%	41%	52%	63%

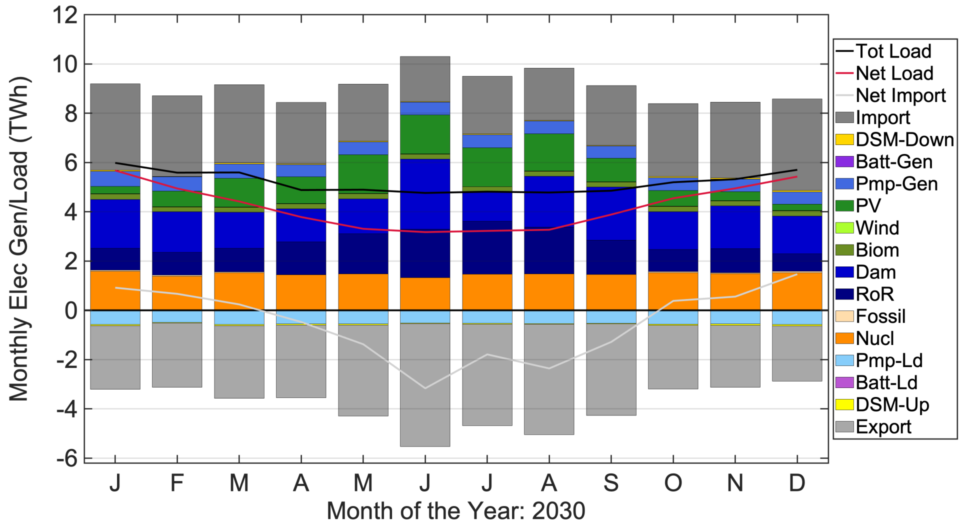
(b) Operational costs

Category	2018	2020			2030			2040			2050		
(kWp)	ref.	low	mod.	high	low	mod.	high	low	mod.	high	low	mod.	high
0-10	100%	94%	95%	96%	76%	78%	80%	66%	68%	69%	64%	64%	63%
10-30	100%	94%	95%	96%	76%	78%	80%	66%	68%	69%	64%	64%	64%
30-100	100%	94%	95%	96%	76%	78%	80%	65%	67%	69%	63%	64%	64%
>100	100%	94%	95%	96%	75%	78%	80%	65%	67%	69%	63%	64%	64%

D Additional figures: electricity generation by technology type

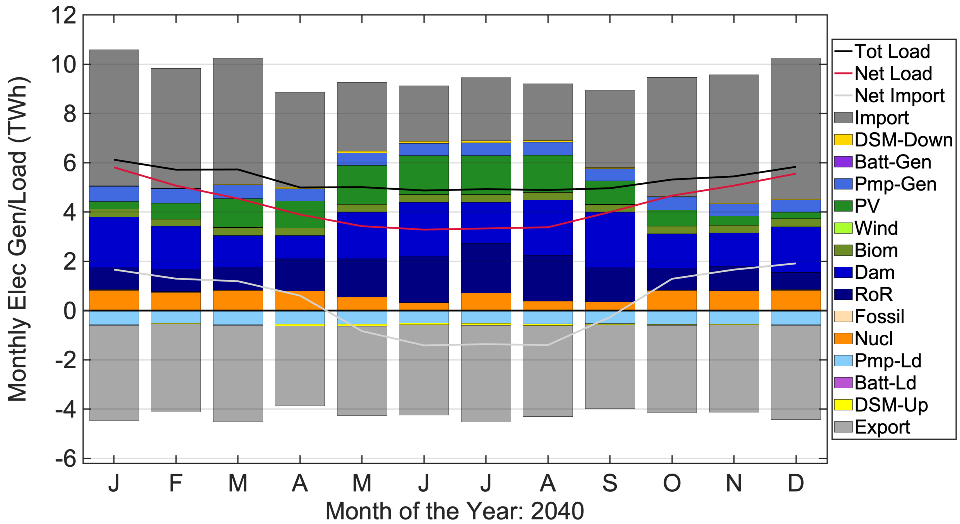


(a) 2020 - Nuclear 60

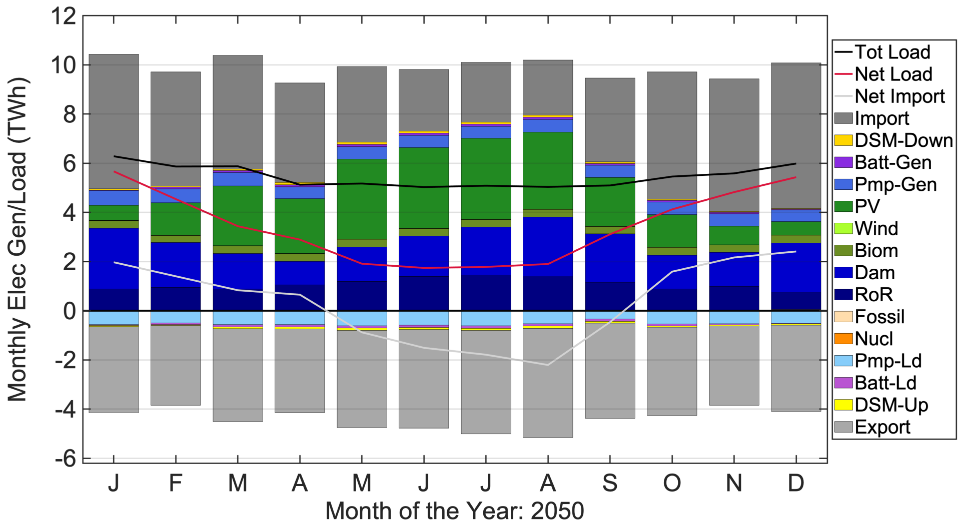


(b) 2030 - Nuclear 60

Figure 34: Monthly electricity generation by technology type for the years 2020 and 2030. Data shown are from the Nuclear-60 scenario.

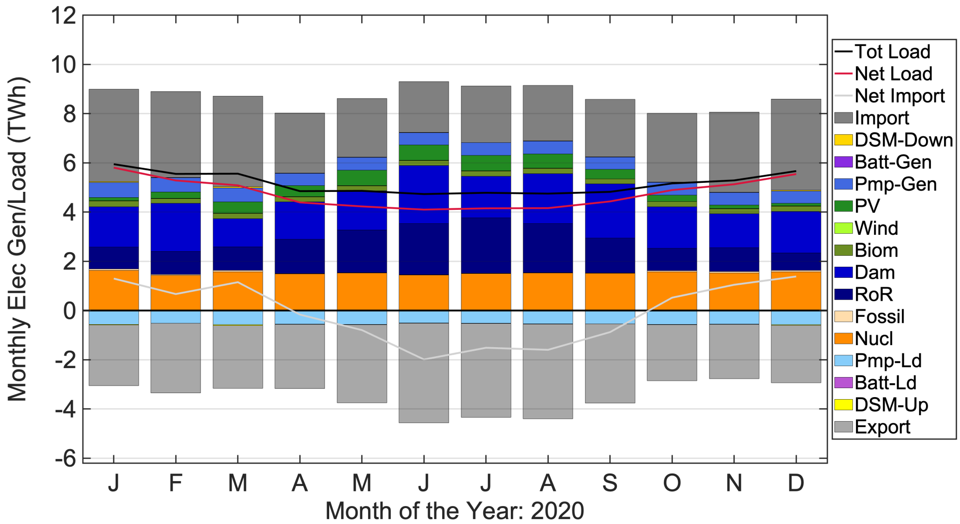


(a) 2040 - Nuclear 60

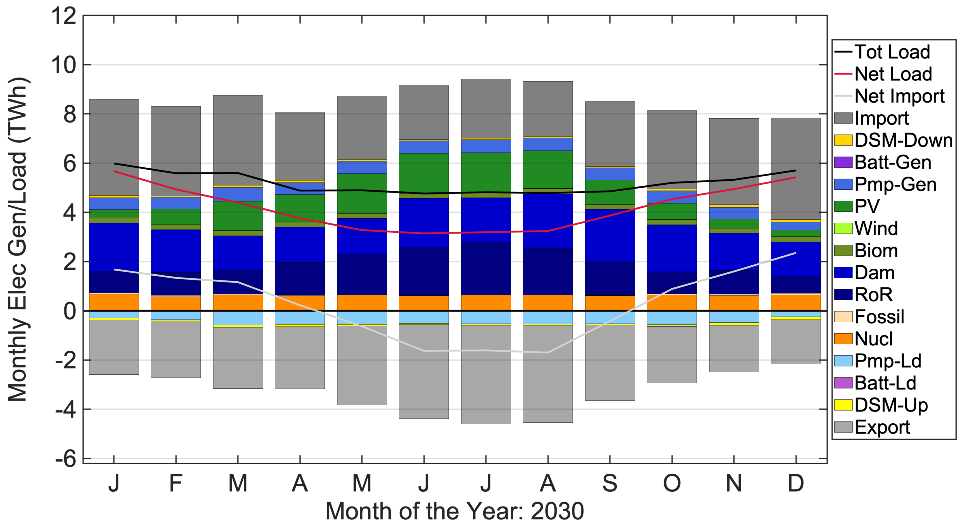


(b) 2050 - Nuclear 60

Figure 35: Monthly electricity generation by technology type for the years 2040 and 2050. Data shown are from the Nuclear-60 scenario.

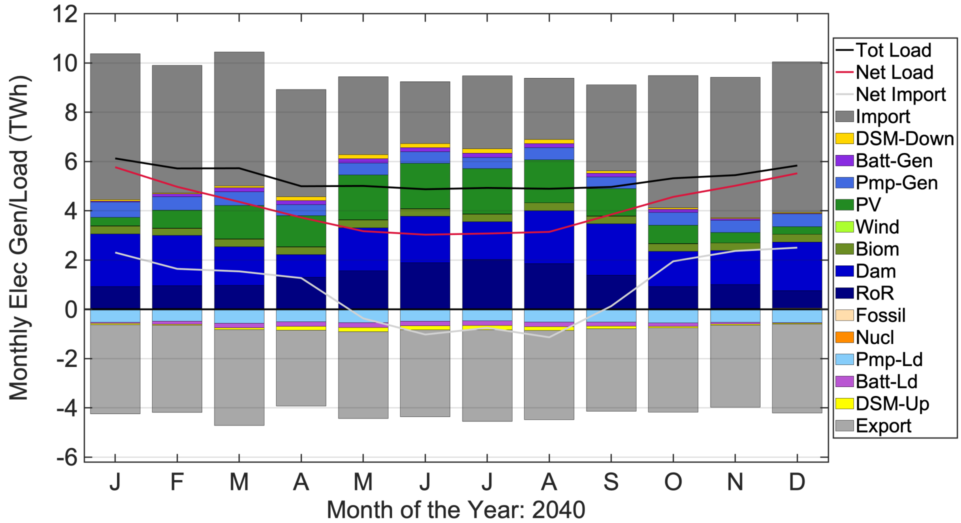


(a) 2020 - High Flexibility

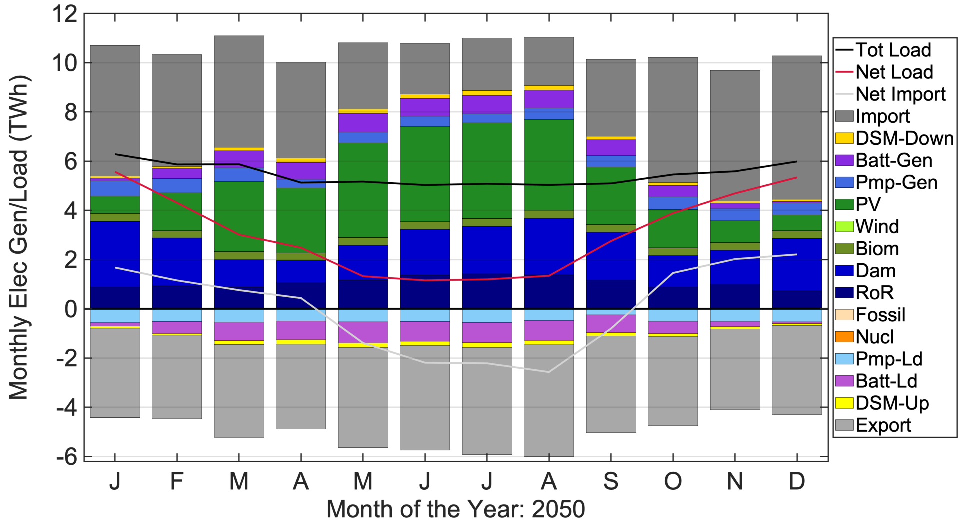


(b) 2030 - High Flexibility

Figure 36: Monthly electricity generation by technology type for the years 2020 and 2030. Data shown are from the High-Flexibility scenario.

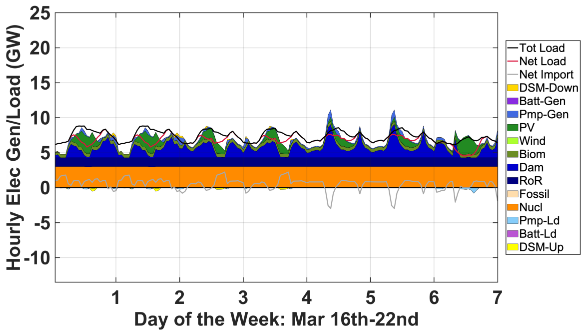


(a) 2040 - High Flexibility

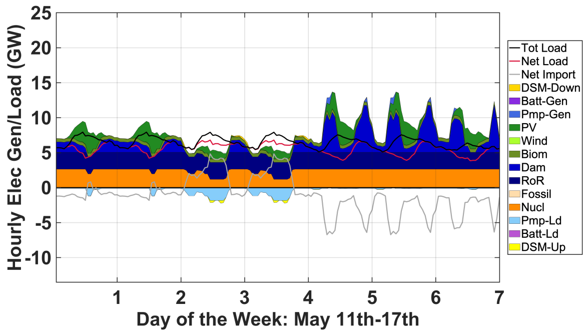


(b) 2050 - High Flexibility

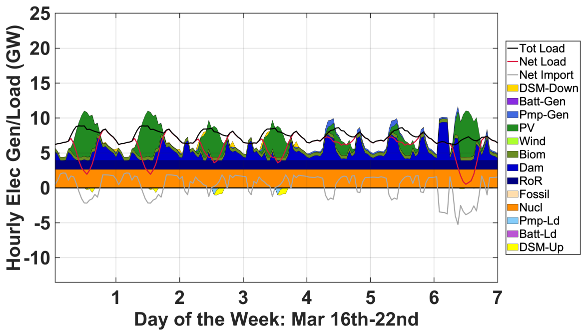
Figure 37: Monthly electricity generation by technology type for the years 2040 and 2050. Data shown are from the High-Flexibility scenario.



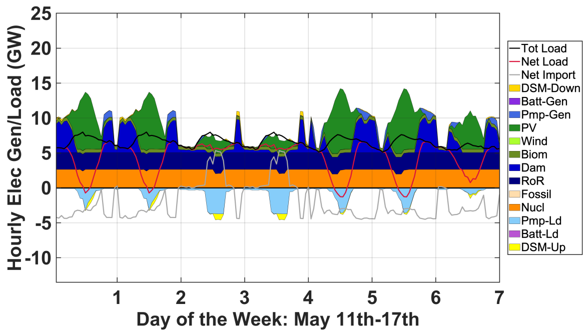
(a) March - 2020



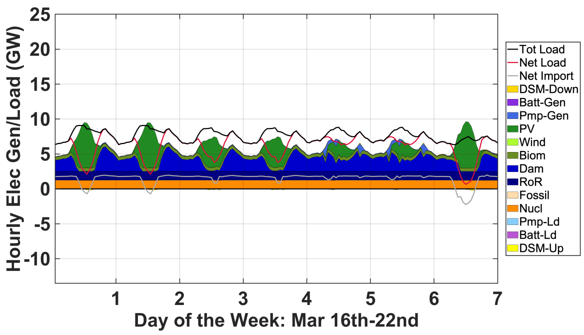
(b) May - 2020



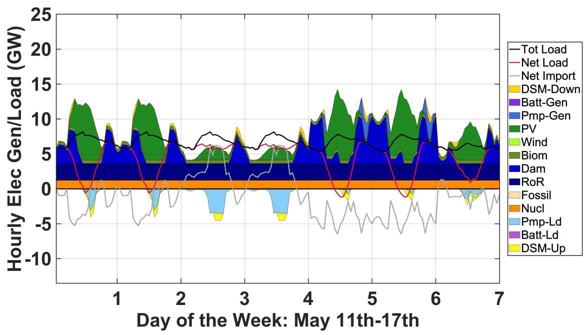
(c) March - 2030



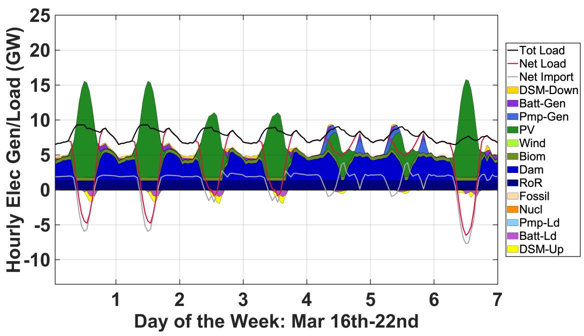
(d) May - 2030



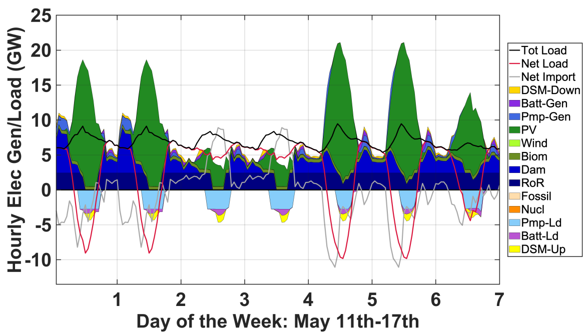
(e) March - 2040



(f) May - 2040



(g) March - 2050



(h) May - 2050

Figure 38: The supply of hourly flexibility is illustrated in the hourly generation by technology type over a week in March and May in 2020 through 2050. Data shown are from the Nuclear-60 scenario.

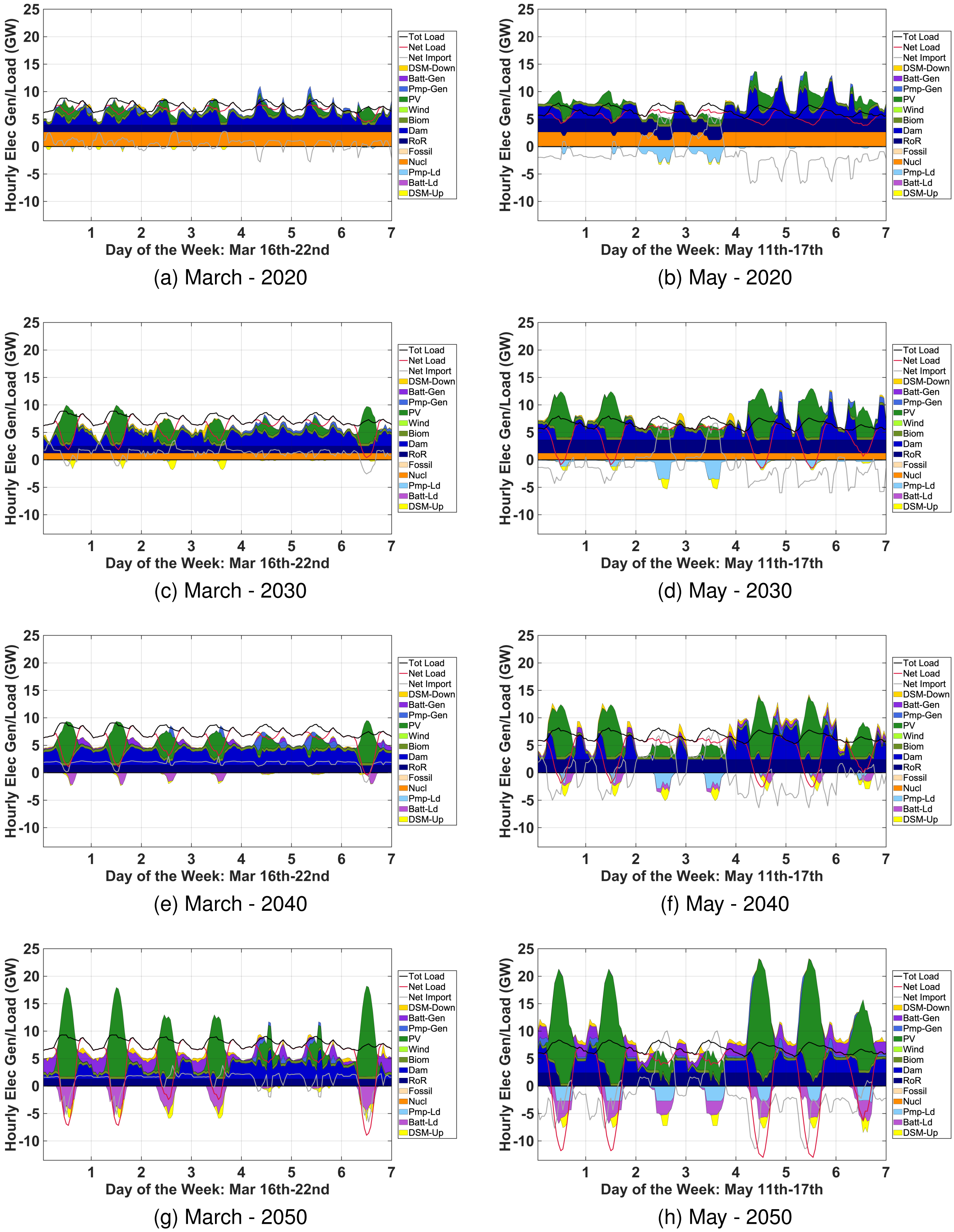


Figure 39: The supply of hourly flexibility is illustrated in the hourly generation by technology type over a week in March and May in 2020 through 2050. Data shown are from the High-Flexibility scenario.

E Additional figures: grid reliability

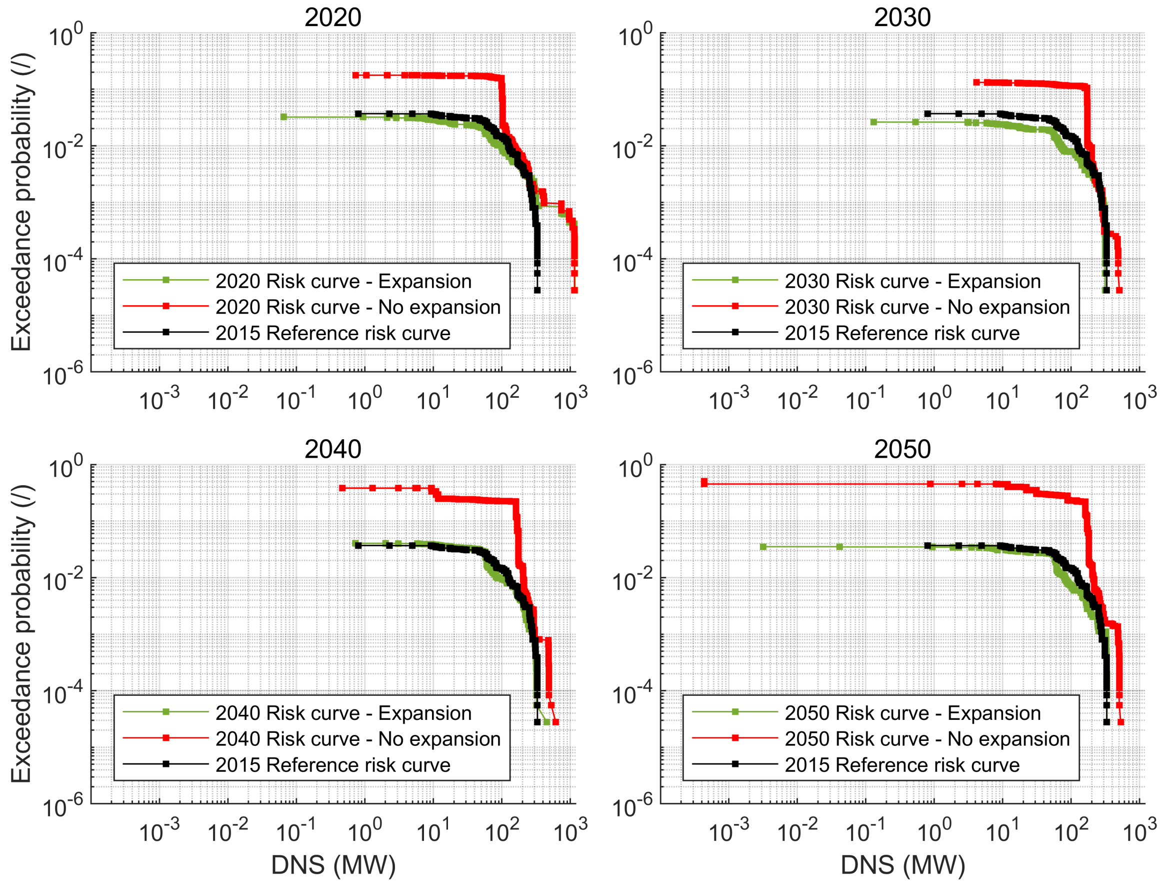


Figure 40: Risk curves for Nuclear-60 scenario: reference (black), scenario-year without expansion (red), scenario-year with expansion (green).

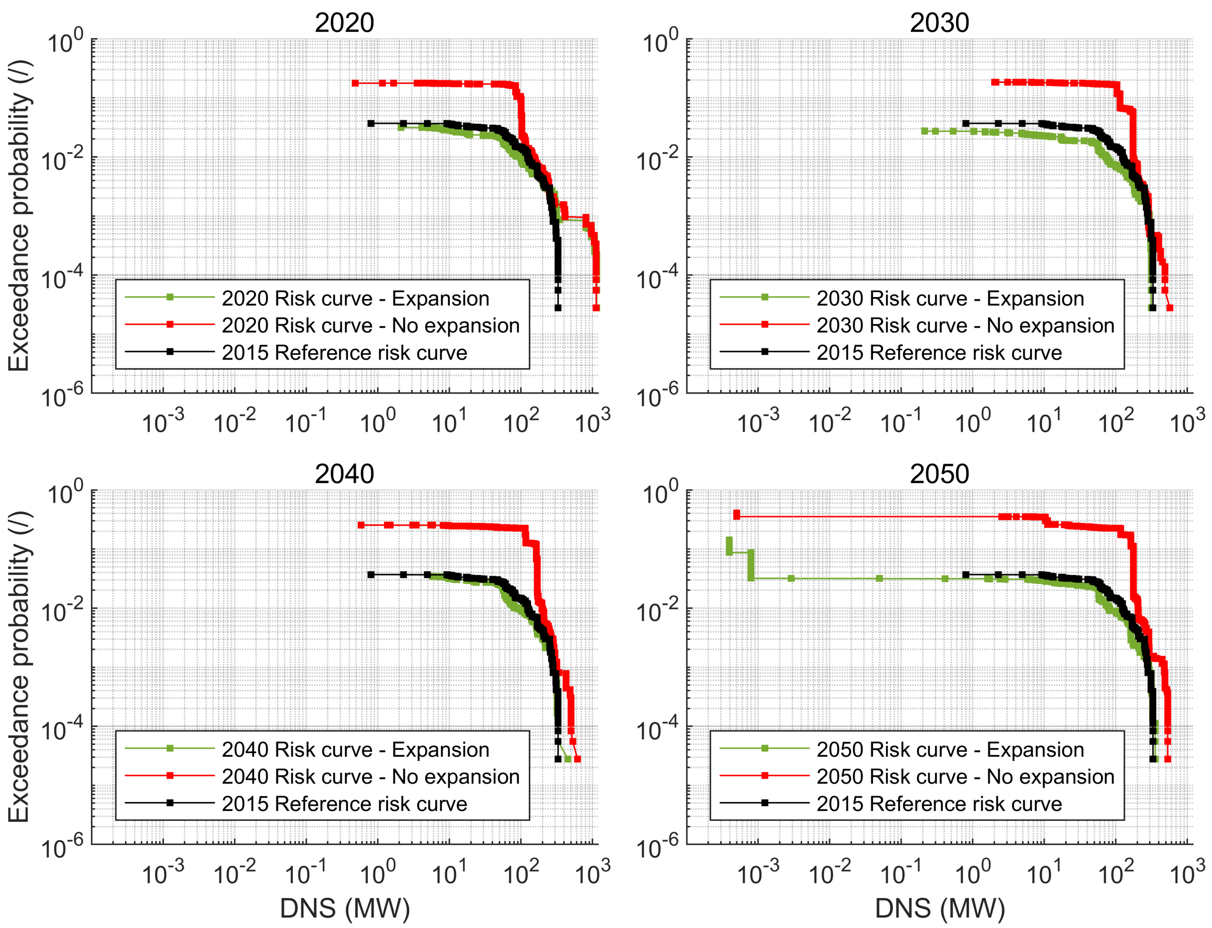


Figure 41: Risk curves for High-Flexibility scenario: reference (black), scenario-year without expansion (red), scenario-year with expansion (green).

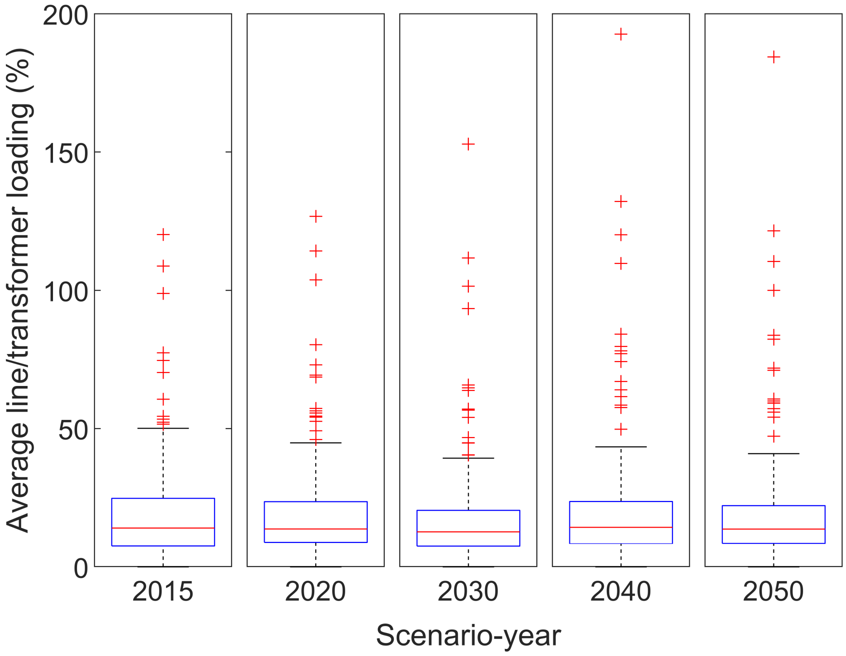


Figure 42: The distribution of the average line/transformer loading in the reference- and scenario-years for the Nuclear-60 scenario.

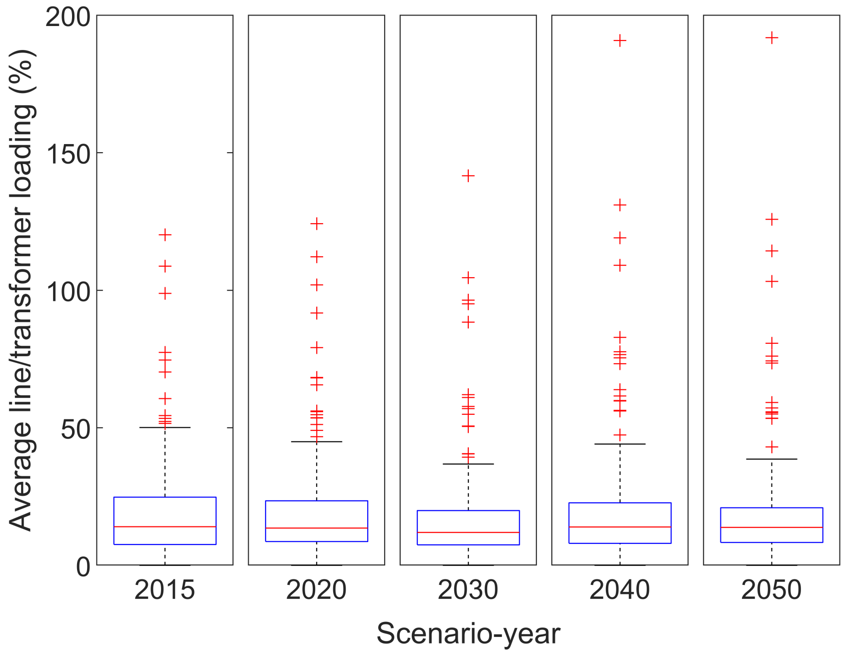


Figure 43: The distribution of the average line/transformer loading in the reference- and scenario-years for the High-Flexibility scenario.