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Multi-objective planning of energy storage technologies for a fully renewable system: Implications for the main stakeholders in Chile

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ABSTRACT

Energy storage systems can cost-effectively balance fluctuations from renewable generation. Also, hydropower dams can provide flexibility, but often cause massive fluctuations in flow releases (hydropeaking), deteriorating the ecology of the downstream rivers. Expanding transmission infrastructure is another flexibility source but is frequently plagued by social opposition and delays. As the decision-making process transcends costs, we developed a multi-objective framework to design a fully renewable power system, such that the tradeoffs between total costs, hydropeaking, and new transmission projects can be assessed from a multi-stakeholder perspective. We planned the Chilean power system for the year 2050 and, based on the obtained trade-off curves (Pareto), we identified the following implications for the different stakeholders. Avoiding new transmission generates little costs (avoiding 30%/100% of transmission costs $< 1\%/ > 3\%$), which is positive for planners but negative for transmission companies. Severe hydropeaking can be mitigated for about 1% of additional costs if transmission is deployed. Avoiding both hydropeaking and transmission is the most extreme scenario, costing 11%. The less the transmission and hydropeaking, the more solar and storage technologies are installed. Cheap solar and storage systems enable policymakers to cost-effectively limit hydropeaking and new transmission, which makes the system greener and more socially acceptable.

1. Introduction

To sustain the earth, greenhouse gas emissions need to stop. In order to meet the Paris Agreement directive of keeping global warming well below 2 °C, this needs to happen shortly after mid-century (Rogelj et al., 2016). However, the more we delay becoming carbon neutral, the more we have to make up for it by becoming carbon negative. Switching our energy production to renewable technologies is a direct solution to avoid carbon emissions. However, to cope with the variability and uncertainty of wind and solar resources, power systems need to become much more flexible than they are today (Yekini Suberu et al., 2014), for example, by deploying transmission and energy storage systems (Steinke et al., 2013), demand-side management (Pamparana et al., 2017), or integrating the different energy sectors (power, transport, gas, water, and heat) (Gulagi et al., 2017).

To assist long-term investment decisions in the energy sector, expansion planning models are commonly used. Specifically, storage expansion planning aims to find the sizes, types, and locations of storage systems that minimize total costs (investment and operation). Haas et al. (2017), Zerrahn and Schill (2017) provide comprehensive reviews about existing modeling approaches. Based on existing storage expansion studies, Cebulla et al. (2018) synthesized the storage requirements for Europe, U.S., and Germany based on over 400 scenarios. It found that, for renewable shares above 50%, the storage park will need to grow strongly beyond the existing capacities, especially if the generation is based on solar photovoltaic rather than on wind. What also became clear from the above references (Haas et al., 2017; Zerrahn and Schill, 2017; Cebulla et al., 2018), which analyzed in total over 150 sources, is that most studies rely only on techno-economic models. While the technical detail is continuously increasing and complex formulations can be found (including stochastic planning approaches (Good et al., 2015; Tedeschi et al., 2013), high technological (Dehghan and Amjady, 2016) and temporal resolutions (Brekken et al., 2011), or multiple technical objectives (Baghaee et al., 2012)), the environmental dimensions are frequently neglected. We believe that these environmental dimensions, such as carbon emissions, social opposition, ecosystem health, or material availability, are extremely relevant when planning future power systems; not only because of their inherent importance but also because considering these dimensions can impact the optimal system design.

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Since the 2000's, there have been increasing efforts to include environmental criteria in planning. To date, the most common environmental target is the minimization of carbon emissions. For example, the team of Loisel et al. (2010) planned storage devices and took a closer look at avoided energy curtailment and carbon prices in scenario-sensitivities (i.e. ex-post analysis of environmental impacts). Shimizukawa et al. (2011) went one step further and endogenized CO_2 emissions in the objective function when sizing storage technologies for power systems with high shares of renewables. This approach, i.e. decision making in the presence of multiple targets that frequently compete with each other, is called multi-objective optimization. Another example is Tuohy and O'Malley (2011), which included minimizing renewable energy curtailments in the objectives as a proxy for maximizing the integration of renewable technologies. Further multi-objective approaches (but in distribution systems) have accounted for pollution, energy losses, and reliability in Ramírez-Rosado and García-Garrido (2012); and for greenhouse gas emissions and grid energy losses in Ippolito et al. (2014).

When planning the deployment of energy storage for large power systems, using multi-objective frameworks (beyond technical targets) is very rare. This is confirmed by the three literature reviews on storage planning mentioned earlier (Haas et al., 2017; Zerrahn and Schill, 2017; Cebulla et al., 2018). Additionally, a recent search (as of July 2018) on google scholar (for the combination of "multi-objective", "energy", and "storage" in the title) only revealed 50 publications. Dismissing the ones that deal with operational scheduling (e.g. optimal control), single-storage design (e.g. residential or vehicle storage sizing), and micro- or distributions grids, we are left with three contributions. The first one (Wen et al., 2016) sized battery storage, tested in a 162-bus system, minimizing costs, duration of blackouts and number of circuit breaker operations. The second one (Saber et al., 2018) calculated distributed storage systems from the viewpoint of an independent system operator. It minimized wind curtailment and transmission congestion while maximizing the profit of storage owners. Only the third study included environmental impacts (Li et al., 2018). Besides optimizing for costs and technical suitability for the different power system services (here: bulk and customer energy management, transmission and distribution support), it included an aggregated lifecycle analysis indicator, called ReCipe (Oliveira et al., 2015). This indicator summarizes the impacts of the storage devices on climate change, human toxicity, particulate matter, and fossil depletion. However, when studying the need for storage, there are other impacts that have not yet been considered in the literature.

1.1. Storage planning and hydropower (hydrologic alteration from hydropeaking)

Hydropower reservoirs have several externalities. One of them relates to their operation. Conventionally, they buffer fluctuations in the net energy demand. This highly variable operation scheme is called hydropeaking and provokes ecosystemic harm because the generated power directly translates into strong and unnatural flow fluctuations in the downstream rivers (Richter et al., 1996; Richter et al., 1997).[1] Some flow variability is healthy and required to sustain life in rivers (Zimmerman et al., 2010). In fact, the natural flow regime is variable over different timescales: minutes to hours during flood peaks, days during high flows, seasons due to precipitation patterns, several years due to extended droughts, and decades because of climate change (Zimmerman et al., 2010; Poff et al., 1997). However, the water flow downstream of hydropower plants can be extremely altered, exhibiting several peaks per day and flow rates even beyond the strongest natural floods. The literature shows ample evidence on how these severe fluctuations of water levels and flow velocities threaten the lotic communities. These include severe changes in food webs and vegetation (Wootton et al., 1996), stranding, drifting, and washing out of entire populations (Cristina Bruno et al., 2010), physiological constraints and problems in reproduction (Vanzo et al., 2016; Carpentier et al., 2017), life cycle disruption (Scheidegger and Bain, 1995), and many more. Altogether, these altered flows degrade the river habitat and stress its aquatic communities, deteriorating their abundance and diversity up to complete extermination (Zimmerman et al., 2010; Brown et al., 2006). More details on these impacts can be consulted in the review of Poff and Zimmerman (2010) and Angus Webb et al. (2013).

The conventional way of measuring hydrologic alteration is with the Indicators of Hydrological Alteration (Richter et al., 1996). This set of metrics relies on five groups related to the flow's monthly magnitude, magnitude and duration of annual extreme water conditions, timing of extreme annual conditions, frequency and duration of pulses, and rate and frequency of water changes (Richter et al., 1996). However, these indicators rely on daily flow resolutions which mask the effect of subdaily patterns (Bevelhimer et al., 2014). Subdaily and even subhourly fluctuations, however, have become more intense due to the integration of renewable generation (Kern et al., 2014; Haas et al., 2015) as well as new market structures (Kern et al., 2012). In response, more recent studies have proposed eco-hydrologic indicators based on higher temporal resolutions. The Richard-Baker index (Baker et al., 2004) is one of them and computes the flow's flashiness (sum of all –up and down–fluctuations normalized by the total flow) (Carpentier et al., 2017; Haas et al., 2015; Kern et al., 2012; Olivares et al., 2015).

Although research from recent years has shown increasing efforts in quantifying hydropeaking in the operation of power grids, so far it has been ignored in expansion planning exercises. The issue is that when ignoring hydropeaking, the optimization tends to recommend a specific infrastructure but is short-sighted to complications that arise during or after its deployment. In the case of hydropower, there are at least two reasons for acknowledging hydropeaking during the infrastructure planning. One is that a compatible ecological operation (less hydropeaking) can help find socially and environmentally sound solutions while decreasing social opposition, making the recommended projects more likely to be built. Secondly, when integrating renewables, we need flexibility, and a more constrained hydropower operation opposes that goal. This tradeoff between both targets has not been captured in the storage planning literature thus far.

1.2. Storage planning and social opposition to transmission

Another socio-environmental impact that is usually neglected when planning storage devices has to do with transmission infrastructure. Around the globe, social opposition plagues grid deployments (Cotton and Devine-Wright, 2012; Cain and Nelson, 2013; Soini et al., 2011). This opposition is considered to be the major bottleneck (Komendantova and Battaglini, 2016), although other aspects are difficulting new transmission line developments. Some of these factors include the many actors inherently involved in such large-scale projects (local governments, federal governments, regulators, residents), substantial investments (and their difficulty to justify and recover the costs), and rights of way, among others (Shahidehpour, 2004). The main concerns relate to the visual impact of the lines and pylons (Elliott and Wadley, 2012), endangerment of bird populations (Bevanger, 1998), noise (Doukas et al., 2011), decrease of property value (Jackson and Pitts, 2010), and electromagnetic-field health concerns —although there is no clear scientific evidence for this issue— (Claassen et al., 2012). Altogether, these issues can result in delays, cost overruns, and even cancellation of the projects. The resulting underinvestment and delays in transmission directly increase congestion costs, energy curtailment, energy losses, and systems maintenance (Shahidehpour, 2004), and can indirectly lead to suboptimal investments in renewable and storage technologies (Haller et al., 2012).

[1] Pumped hydro storage is safe from this issue as its turbined flows are usually not released into rivers.

From social sciences, there are several studies about public acceptance of energy infrastructure; (Cohen et al., 2014) for example. They conclude that transmission, in contrast to wind turbines, is not perceived as green technology, thus facing more resistance. Another study (Lienert et al., 2015) picked up this idea and tested whether the transmission lines required to support the energy transition would increase social approval. Although their findings were positive, informing this link (power lines needed for integrating renewables) is challenging. In the end, when it comes to transmission, competitive electricity prices alone are insufficient to gain social support; the public wishes to better understand the need for transmission and alternatives for it (Komendantova and Battaglini, 2016). One technical alternative is underground lines. Although they are more costly (Navrud et al., 2008), their social benefits have shown to outweigh their costs in populated areas (Navrud et al., 2008). If this solution is targeted, clearly, its cost should be considered in the planning.

Within storage expansion literature, transmission lines have been considered from a technical point of view only. In the extreme, storage and transmission can be competitors. If storage is to become very cheap (and in presence of local generation options), all energy could be stored locally. And vice-versa, affordable transmission could eliminate the need for storage because somewhere in the world there is always wind blowing and sun shining. Nevertheless, both extremes seem unpractical from today's perspective, which is why transmission storage systems are perceived as complements (Steinke et al., 2013). For example, storage can smoothen the fluctuation of a solar power plant and, thus, optimize the utilization of a transmission line (Qi et al., 2015). Similarly, having a strong grid allows transmitting energy from different regions to the storage devices, which buffer the received fluctuations (Haller et al., 2012; Bussar et al., 2016). Delaying investments in flexibility sources leads to overall suboptimal decisions, including lower renewable generation and higher emissions from fossil sources (Haller et al., 2012).

From the analyzed studies, it becomes clear that the externalities of transmission lines have not widely been dealt with when planning the deployment of storage systems. Maybe it is because these externalities are tough to be forecasted and, thus, challenging to be translated into economic terms (which would then be used in the optimization models). Not including them in the optimization process is similar to the conflict of hydropeaking, in the sense that a model recommends solutions that in practice will face unforeseen inconveniences. A direct response would be treating transmission investment as a separate dimension in multi-objective optimization.

1.3. Contribution and research questions

The above literature review shows that multi-objective optimization for storage planning is scarce. However, there are relevant dimensions beyond economics that have to be considered, even when planning 100% renewable power systems. In fact, the practice has shown that transmission infrastructure and hydropeaking are such dimensions. Our working hypothesis is that limiting new transmission infrastructure and constraining hydropeaking are aspects that strongly impact the component-sizing of future power systems, and that explicitly considering both aspects allows for finding cost-effective mitigation strategies. Consistently, in this work, we formulate a multi-objective framework for optimizing energy storage expansion decisions. Beyond the framework itself, we concretely contribute by answering the following questions for the involved stakeholders:

- Transmission and generation companies: How relevant is additional transmission infrastructure and what would it cost to avoid new lines? And, is there a bias towards a certain generation technology when relying on weaker grids?
- Storage companies: What happens to the overall storage requirements when costs are minimized next to transmission and hydropeaking? How does the demand for specific storage technologies change?
- Environmental organizations: Can we mitigate hydropeaking at reasonable costs? And, is that cost still bearable if at the same time the society opposes all new transmission lines?

We illustrate the above points in a real power system. We chose Chile as a case study because it has a significant hydropower park (susceptible to ecological alteration), vast distances between generation and load centers (potentially requiring intensive transmission investments), and ambitious renewable targets (triggering the need for storage). These targets include an official political goal of reaching 70% of renewable generation by 2050 (Ministerio de Energía, 2015) and a research vision of becoming Latin America's solar exporter (Jimenez-Estevez et al., 2015).

The following section will detail our methods, including the description of our case study. Section 3 will discuss the results, explaining the found tradeoffs from the perspective of the different stakeholders. Finally, Section 4 will conclude, show the policy implications, and outline the future work.

2. Methods and data

To design the optimal storage and 100% renewable generation mix including externalities, such as from building transmission lines and hydrologic alteration from hydropower operation, we propose a multi-objective framework consisting of four steps. These are multi-objective formulation, power system expansion tool, inputs, and multi-objective analysis, as shown by the blocks i, ii, iii, and iv in Fig. 1. We will briefly introduce these steps in the following paragraphs and then provide a more detailed description in subsections 2.1–2.4.

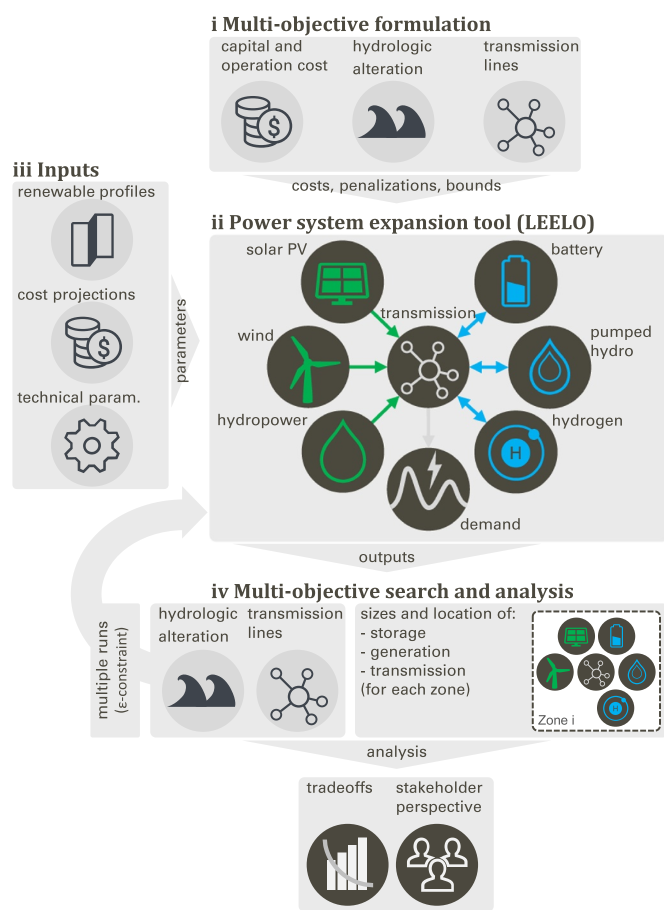

Fig. 1. Multi-objective optimization framework, including the i) multi-objective formulation, ii) power system expansion tool (LEELO), iii) inputs, and iv) multi-objective search and analysis.

i. **Multi-objective formulation**
The main concerns of the involved stakeholders need to be identified. The conventional target is energy equity (affordability and accessibility), i.e. delivering power to all users at minimum costs. There are also socio-environmental concerns related to power system planning. Our framework is general enough to include most types of externalities, but in this work, we focus on two: minimizing hydropeaking and minimizing new transmission facilities. From a modeling perspective, these can be implemented in two equivalent alternatives: penalizations (in the objective function) or bounds (in the constraints).

ii. **Power system expansion tool (LEELO)**
Here we use a linear optimization tool, called LEELO (Long-term Energy Expansion Linear Optimization), for planning the power system. The main outputs involve the investments (sizes and location of storage, generation, and transmission), the operation of the system, and the socio-environmental parameters. The tool can handle the design of a multi-nodal power system with a detailed representation of hydropower.

iii. **Inputs**
The main inputs relate to technical parameters (power plants, storage technologies, transmission infrastructure and projections of electricity demand), cost projections (capital and operational cost), and renewable resources (profiles). We set up a database to plan the system of Chile in the year 2050, based on a full milestone year with an hourly resolution. We considered three kinds of storage devices (batteries, pumped hydro, hydrogen), and three kinds of renewable generation (solar photovoltaic, wind, existing hydropower cascades).

iv. **Multi-objective search and analysis**
First, the outputs of the tool are compiled and processed into a set of key indicators. Then, the tool is run multiple times to systematically form the Pareto Front, with which we analyze the tradeoffs between cost, hydrologic alteration, and new transmission lines. We adopt the perspective of the involved stakeholders of the power system (transmission and generation companies, energy storage companies, environmental organizations) to address the main implications when planning with multiple dimensions.

2.1. Multi-objective formulation

We aim to find the design of the power system (d_{opt}) that minimizes the different components of the objective function. These objectives, shown in Eq. (1), are composed of costs (f_{costs}), hydropeaking ($f_{hydropeaking}$), and transmission ($f_{transmission}$), which we will explore now. The decision space of feasible designs (D) is given by the power system expansion tool (see Section 2.2).

$$d_{opt} = \underset{d \epsilon D}{\operatorname{argmin}} \begin{bmatrix} f_{costs}(d) \\ f_{hydropeaking}(d) \\ f_{transmission}(d) \end{bmatrix} \quad (1)$$

2.1.1. Objective A: minimize costs

One objective is minimizing the total costs, composed of investment and operating costs. Investment cost includes building energy storage systems, generators (solar photovoltaic and wind power plants), and transmission lines. The investment costs are treated as annuities, which is a function of each technology's lifetime and a given interest rate. Operating, variable and fixed costs are mainly the maintenance costs of all the built infrastructure.

Note that the *cost* of transmission infrastructure is part of this objective function. Yet, to confront other complications that transmission faces during its deployment, it is additionally treated as a separate dimension.

2.1.2. Objective B: minimize hydrologic alteration

We measure hydrologic alteration with the Richard-Baker (RB) index. Recalling its definition from the introduction, for one hydropower plant, this is the sum of the flow variations divided by the total flow over a given time horizon. Here, the time step is one hour, and the horizon one year (i.e. 8760 flow variations are summarized into one index, per hydropower plant). To summarize the operation of the whole hydropower system (our case study includes over 40 cascading hydropower plants) into one index, we computed the weighted sum between the RB index of a hydropower plant and its installed capacity.

Modeling the RB index endogenously in the optimization would implicate losing the linearity of the model (which would burden the solving times) because both the hourly flows and the total flows are decision variables that would be dividing each other. As a proxy to the RB index in the optimization, we decided to minimize the ramps of the hydropower park (i.e. the numerator of the RB index). As a side note, modeling ramps in linear optimization requires using two auxiliary variables. One for the sum of the positive ramps and another for the negative ramps. Once the optimum is found, we used the RB index for analysis (Section 2.4).

2.1.3. Objective C: minimize new transmission lines

The deployment of new transmission lines is frequently burdened by severe execution delays –if built at all–, and social opposition. In combination with other factors, this tends to result in much higher costs than the projections originally considered in the optimization. Treating additional transmission infrastructure as a separate dimension allows understanding about how much the other dimensions (here: costs and hydrological alteration) would suffer if only a given level of transmission can be built.

Concretely, this objective is defined as the sum of (new) transmission capacity to be built, measured in MW. Recurring to life-cycle analysis literature, more complex treatments can be found, for example land use, especially in sensitive territories. However, as a first approximation, especially in a tri-dimensional objective function, we decided to take the simplest expression (MW) for the ease of communicability. This also implies that a, say, 1 MW line of 1 km has the same relevance (for the model) as a 1 MW line of 1000 km (note that in our case study the length of all potential lines are of the same order of magnitude, making this issue less relevant than in other cases).

2.2. Optimization tool (LEELO)

LEELO is an optimization tool to design fully-renewable multi-nodal power systems. The main objective of LEELO is sizing and siting energy storage, renewable energy, and transmission systems. In contrast to other available models, LEELO's strengths are: having a detailed representation of cascading hydropower (flow routing), the option to include different power system services (power reserves and energy autonomy), and considering multiple-objectives (an extension we performed for the present publication). LEELO is based on cost minimization, i.e. it adopts a welfare-planning perspective (this also means that the market feasibility of the recommended solutions is out of scope). Below, we will provide a general overview of LEELO's main characteristics. For further detail, we recommend consulting our previous publication (Haas et al., 2018a).

LEELO is multi-nodal, meaning that it captures different geographic zones. The zones are interconnected with transmission infrastructure, which we represented with a transport model (i.e. voltage differences and phase angles are ignored, which is a common simplification when planning nation-wide grids). Energy losses due to transmission are considered to be proportional to the transmitted energy. Each zone is modeled as a copper plate (i.e. sub-transmission and distribution systems are not captured). Other energy sectors, such as heat, transport, and gas, are not included.

Storage systems are modeled in terms of their capacities, energy-to-power ratio, cycling, and energy balance. The former refers to the (maximum) energy capacity and power capacity, which are two independent decision variables. More specifically, the costs for energy capacities refer to the effective capacity (e.g. in order to have an effective energy capacity of 100 MWh for a device with a maximum depth of discharge of 80%, 125 MWh have to be purchased). Limiting the energy-to-power ratio makes sure the model avoids infeasible configurations (for example batteries with, say, weeks of storage capacity). The cycling is captured in terms of a maximum number of yearly cycles coherent with their lifetime (e.g. 10.000 cycles in 10 years results in 1.000 cycles per year), in order to (indirectly) capturing the aging of the battery.

The model considers different profiles for the renewable generators, depending on their location. The amount of energy curtailed is verified ex-post to make sure economically unattractive projects are avoided.

Cascading hydropower (hydropower plants that are constructed in series, one downstream of another) are modeled with connectivity vectors to capture the flow routing. Some hydropower plants have reservoirs. Thus, they have an energy balance equation similar to the energy storage systems. To convert turbined water to power, we assumed a constant yield.

Regarding the multiple power system services, the most fundamental one in available models is energy balance, meaning that in each time step supply needs to meet demand. In our previous publication (Haas et al., 2018a), we proposed to include further services: power reserves (leaving capacity to ramp-up and ramp-down) for tackling short-term forecast errors and energy autonomy (leaving energy reserves) to confront long-term deviations in the used weather inputs. We found that both services impact the final storage investment decisions. Also in the present study, we used this more complex model.

2.3. Inputs

The main inputs include technical parameters, cost projections, and renewable profiles, and can openly be accessed online (Haas, 2018). For even further details, please consult our previous publication (Haas et al., 2018a). We follow a brownfield approach that considers the existing transmission lines and hydropower park as inputs and assumes that the current thermal power plants will be fully decommissioned by 2050. As follows, we will only explain the main assumptions and data sources after briefly introducing the main characteristics of the Chilean power system.

Chile is a country with extremely high potential for renewable technologies (see Fig. 2 for a simplified schematic about the main topology and zones of our case study). The Atacama Desert in the north, with the world's highest levels of irradiation, is ideal for a solar pole (zones z_3 and z_4) (Haas et al., 2018b). The high Andes, combined with precipitation, offer in the center and south a strong hydropower resource (z_1 and z_2). And the Pacific Coast refreshes the almost 4300 km long country with fast winds for turbines (z_1 to z_4). These resources are not only high but also virtually unconstrained in space. The load is distributed quite unevenly, most of it being concentrated in Chile's center close to the largest cities (z_2). The north is sparsely populated and requires electricity mostly for copper mines (z_3 and z_4), whereas the south exhibits many touristic landscapes (social opposition) and is characterized mostly by a residential demand (z_1). Altogether, this configuration makes planning the future electricity system a challenging task.

For the definition of the zones, we segmented the country across the main transmission bottlenecks. The corresponding (existing) transmission capacities come from the database of the national power system operator (Coordinador Eléctrico Nacional, 2017). From here it results that the four zones are interconnected by lines of capacities ranging from 1.5 to 2.0 GW, totaling 5.1 GW.

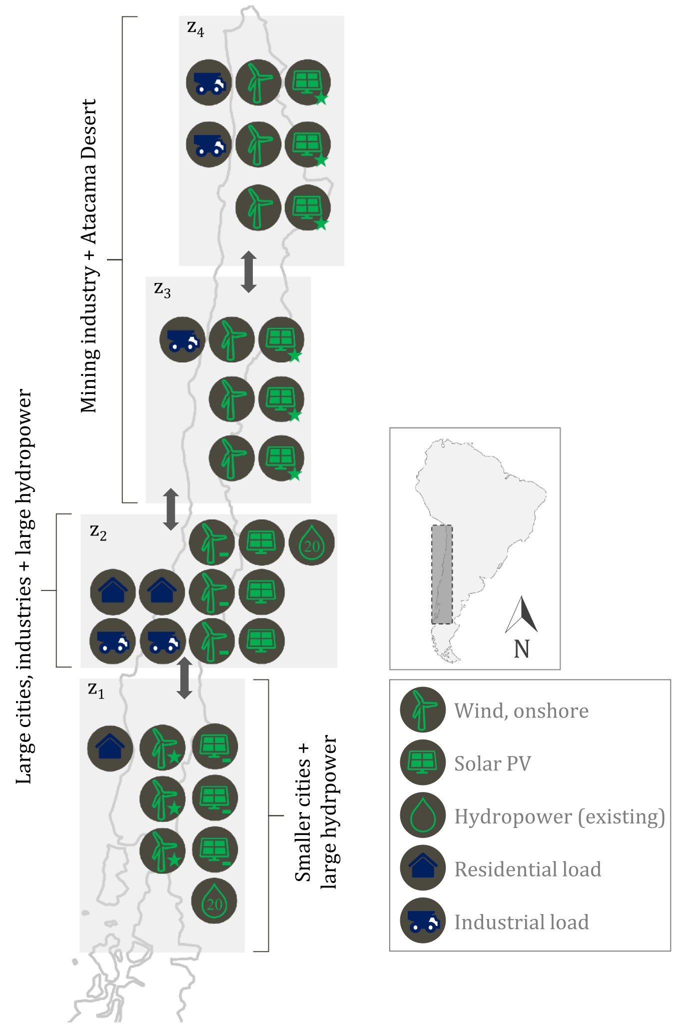

Fig. 2. Schematic of the Chilean power system, including solar PV and wind resources, as well as existing hydropower plants (outstanding resources marked with a star, and lower resources with a minus-sign), and residential and industrial load.

Regarding generation technologies, we considered solar PV (single-axis tracking) and wind turbines (onshore). The resource profiles were obtained from validated online tools (*Solar and Wind Energy Explorer* (Department of Geophysics, 2012a; Department of Geophysics, 2012b; Molina et al., 2017)). In each zone, we considered three locations for each technology. We also modeled the existing hydropower park, consisting of about 20 cascading installations in each zone z_1 and z_2. Their connectivity and inflows are based on Alvarez et al. (2017), Coordinador Eléctrico Nacional (nd.). For the last hydropower plant of each cascade, we assumed an ecological flow equal to ten percent of the nominal turbine flow. Hydropower plants (reservoirs and run-of-river) are not expanded.

For storage technologies, we chose to model Li-ion batteries, pumped hydro storage, and hydrogen systems (with gas turbines for reconversion back to electricity, and CO_2 scrubbers).

To obtain the load of 2050, we took the current demand profiles of zones z_1, z_2, and z_3 from Alvarez et al. (2017), and of zone z_4 from Coordinador Eléctrico Nacional (2017), and applied the yearly growth rates as estimated by the National Energy Commission of Chile. This resulted in a (total) average load and peak load of 23 and 29 GW, respectively. For context, these numbers imply tripling Chile's current load. This challenge is additional to making the system 100% renewable. We considered a penalty for unserved energy of 10.000 €/MWh.

As what refers to costs, we used the database from Breyer's team (Child et al., 2017). Based on experience curves and projections of to-be-deployed capacities, they forecast the costs of the main renewable and storage technologies. This forecast has been widely used in scientific publications in the last years (Gulagi et al., 2017; Child et al., 2017; Breyer et al., 2017; Kilickaplan et al., 2017; Koskinen and Breyer, 2016; Bogdanov et al., 2016). For pumped hydro, we recurred to values compatible with Kousksou et al. (2013). For calculating the annuities of capital expenditures, we took the expected lifetime of each technology (Child et al., 2017) and a yearly interest rate of 5%, which is in line with other equivalent studies (i.e. focus on mature technologies in regions with high geopolitical stability) (Cebulla, 2017).

2.4. Multi-objective search and analysis

Each model run gives us one solution consisting of a recommended generation mix (wind, solar), storage mix (batteries, pumped hydro, hydrogen), additional transmission lines, and the operation of the whole system for the simulated year. To systematically screen the space of Pareto-optimal solutions, the model is run multiple times. We follow the *ε-constrained method*, which consists of minimizing one dimension of the objective function while constraining the ranges of the remaining ones. Note that the literature shows other options for exploring the Pareto Front, such as Monte Carlo (randomly weighting each part of the objective function), the *augmented ε-constrained method* (a more efficient formulation of *ε-constrained*) (Mavrotas, 2009), or *Borg* (for evolutionary computing frameworks) (Hadka and Reed, 2013). The two latter become especially relevant when computing time is limited (i.e. to produce the best front with few runs). In our case study, computing times were not critical, which is why using the *ε-constrained method* was enough.

By definition, each found solution is optimal (given the used range of the objective function). This case is direct for the dimensions of costs and additional transmission, where the target to be minimized is explicitly modeled in our tool. In the case of mitigating hydrologic alteration, we remind that our model minimizes total hydropower ramps in the objective function as a proxy for the ecological index (the ecological index is only computed during post-processing). Due to this proxy, it could happen that some of the found solutions are not Pareto-optimal. For this reason, we test each solution for Pareto-Optimality and filter out the non-dominant ones.

For the final analysis, we will adopt the perspective of the different stakeholders involved in power system planning. Decision making in multi-dimensional spaces is inherently complex, which is why we focused on providing a small set of well-selected indicators for each stakeholder. Namely, for the transmission companies and generation companies, we will describe the tradeoffs related to transmission investments and the resulting generation mix (with the ratio between installed solar photovoltaic and wind power capacity). For the storage companies, we will focus on the power capacities of the total storage requirements and the individual storage requirements. Finally, for the environmental organizations, we will analyze the tradeoffs between mitigating hydropeaking, new transmission, and costs.

3. Results and discussion

In this section, we will first present a general overview of the results. We will then analyze the findings in perspective of the different stakeholders in a power system: Subsection 3.1 will describe the implications for transmission and generation companies, subsection 3.2 for storage companies, and subsection 3.3 for environmental stakeholders.

To find the surface of optimal solutions (the Pareto Front), we run our model about 100 times. Each scenario takes around 30 min to solve on an i7-7700 (4 cores of 3.6 GHz), 32 GB of memory, with CPLEX v12.8. As a comment about the feasibility of the recommended power system design, in all scenarios, 100% of the energy demand is met (no unserved energy) and the amount of curtailed energy is below 3%.

The resulting Pareto Front is shown in Fig. 3. The three axes correspond to the three objectives to be minimized: costs, transmission, and hydropeaking (in x, y, and z, respectively). Costs range between 34.6 and 38.5 €/MWh, additional transmission between 0.0 and 7.0 GW (which is about double the current capacity), and hydropeaking between 0.00 and 0.16 (measured with the Richard-Baker flashiness index, where the upper extreme is at least one order of magnitude more flashy than a natural regime). The green dot at the lower left corner is the point where we would like to be: low cost, no hydropeaking, and no new transmission systems. In practice, we cannot achieve that point, and as a consequence, the solutions are distributed around it. The color code indicates investment decisions, in the case of Fig. 3 that is the ratio between solar PV and wind capacities.

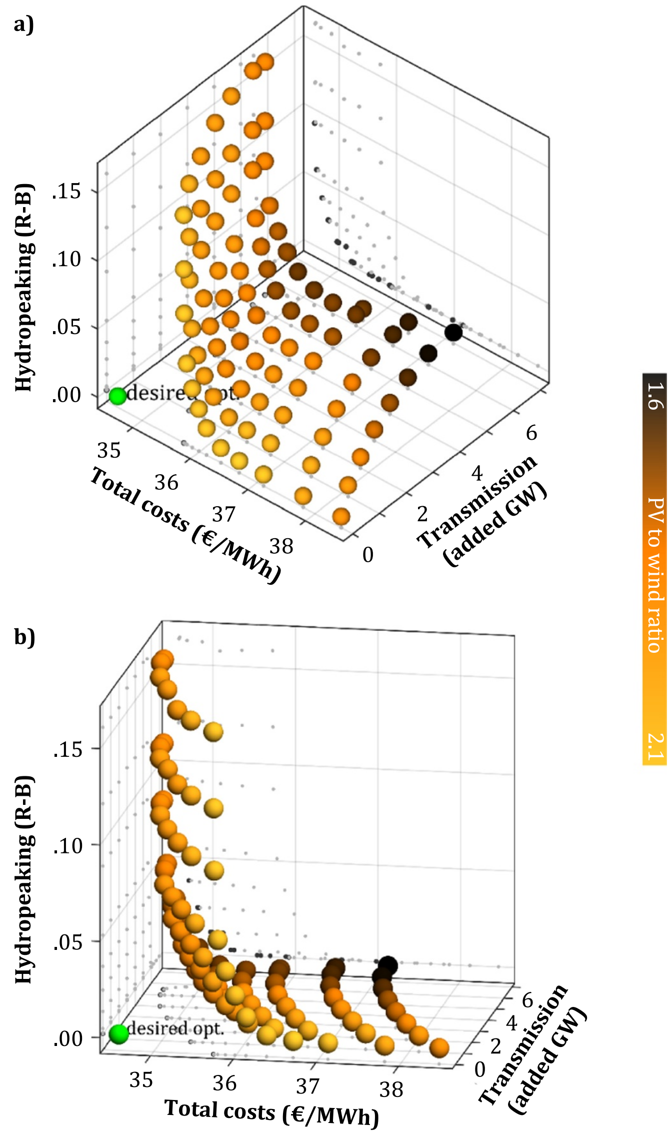

Fig. 3. Pareto Front for storage planning: costs versus transmission versus hydropeaking. The color shows investments in renewable systems (solar to wind ratio). Each solution (sphere) is projected on the faces of the cube in grey, and highlighted in black if the said projection is Pareto-optimal on the corresponding face. Both figures (a and b) show the same results but with different rotation.

Table 1
Main investment decisions for selected scenarios from the Pareto Front.

Level of transmission/ hydropeaking	Costs (Eur/ MWh)	Cost (rel. to base case)	Hydropeaking (RB)	Transmission (added GW)	Solar to wind (GW_{PV}/ GW_{wind})	BESS (GW)	PHS (GW)	H_2 (GW)
TX_100%, HP_max (Base Case)	34.6	*100%*	*0.16*	*5.5*	*1.8*	*6.9*	*9.6*	*13.1*
TX_0%, HP_max	35.7	103%	0.16	0.0	2.1	11.6	9.6	12.8
TX_100%, HP_min	37.2	107%	0.00	7.0	1.6	7.9	9.6	13.2
TX_0%, HP_min	38.5	111%	0.00	0.0	1.9	12.9	9.6	13.3
TX_70%, HP_max	34.6	100%	0.16	5.0	1.9	7.0	9.6	13.1
TX_15%, HP_max	35.4	102%	0.16	1.0	2.0	10.1	9.6	13.1
TX_0%, HP_0.01	36.1	104%	0.01	0.0	2.1	12.5	9.6	13.1
TX_15%, HP_0.01	35.8	103%	0.01	1.0	1.9	11.2	9.6	13.2
TX_100%, HP_0.01	35.0	101%	0.01	5.9	1.7	7.7	9.6	13.2

In general terms, the found Pareto Front has the following shape: it is asymptotic to the plane of hydropeaking/transmission (yz) and cost/transmission (xy). This means that on the one hand, the first efforts of reducing hydropeaking are very cheap, and on the other hand, the last efforts are expensive. Furthermore, the front side of the Pareto Front is rotated outwards, and all cross-sections in the cost-hydropeaking plane (xz) are hyperbolic. This rotation means that if new transmission facilities are not built, the costs increase, but the overall behavior remains similar. Or in other words, for a given level of hydropeaking, the resulting costs are higher if less transmission is built.

Let's now discover what the results mean for each stakeholder in particular. Some selected scenarios to be discussed are displayed in Table 1.

3.1. Transmission and generation companies

Here, we will first explore the implications of our findings for transmission companies, followed by generation companies. When comparing the different solutions of the Pareto Front, we will use the minimum cost solution (upper left point, where both transmission and hydropeaking are maximum) as base case.

Recall from the methods, that transmission infrastructure is captured in the cost dimension (capital and operational), as well as in its own dimension (to account for its externalities). When trying to minimize the main transmission facilities, avoiding (the last) 30% of transmission can come at almost no additional cost ($<$ 1%). This fact can be seen in Fig. 3, where all solutions that have over 5 GW of grid expansion are close to the axis of minimum cost. The costs of avoiding 85% of new transmission start around 2%. Building new transmission shows an important impact on costs only between 0 and 1 GW (the first 15%). Renouncing to all new transmission increases total costs between 3% and 11% depending on the desired level of hydropeaking. These costs seem small in the context of social externalities.

Given that the business model of transmission companies relies on building and operating grid infrastructure, are the found results good or bad news for them? The answer has different components. First, given the difficulty of decreasing social opposition of transmission lines, even in the context for the energy transition (Lienert et al., 2015), it is unlikely that the least-cost point can be achieved in practice anyways. Secondly, the marginal cost saving of the last GWs of transmission capacity is very low, which allows the transmission companies to focus on key-projects, without letting go of valuable business opportunities. Such projects could include power lines in less populated areas such as a corridor in the Atacama Desert or optimizing existing lines without affecting their visuals (e.g. replacement of conductors) in more conflictive regions. In conclusion, the fact that *some* of the new transmission can be avoided for cheap is good news for transmission planners. However, the *overall* saving potential of new transmission (only $<$ 11% of total system costs when transmission is doubled) is inconvenient for transmission companies that want to grow. Especially after installing the first 2 GW, the marginal savings are meager (under the made cost-assumptions). However, other factors not considered here could also play a role. For example, interconnecting energy sectors (Gulagi et al., 2017), Chile becoming an H_2 exporting country (Hosseini and Wahid, 2016), or planning systems that are also robust, resilient, and adaptive (Haasnoot et al., 2013) are elements that could impact the relevance of transmission infrastructure. Furthermore, we underline that we refer to investments of the main transmission system only, while sub-transmission and distribution systems are beyond our scope.

To understand the tradeoffs for generation companies, we need to take a look at the color scale of Fig. 3, which indicates the ratio between the installed capacities of solar and wind power plants (from grey to yellow, the solutions rely more strongly on solar generation). From here we see that, when new transmission capacities are constrained, the system relies more on solar. This relates to the fact that solar with storage can be cost-effective in most regions, whereas wind needs to be transmitted from the good spots to the load centers. In the extremes, when the maximum transmission is deployed, solar exceeds wind capacity by 60% (ratio of 1.6), and when no transmission is installed, solar exceeds wind by 110% (ratio of 2.1). It becomes clear that the solar sector has a lot to gain if the transmission system is not fully expanded. In general, renewable generation companies are currently exposed to intensive discussions about the integration costs (direct and indirect) needed for achieving highly renewable systems. Transmission lines are one of these externalities (Navrud et al., 2008), which, as shown above, can be avoided for little costs. Yet, integration costs remain in the form of storage, but these face less social opposition. Overall, that is good news for generation companies.

In short, transmission can be avoided for little economic effort, in the presence of a robust solar-storage strategy. Based on this analysis, the business case for future transmission lines seems limited. For planners and policymakers, especially in zones with strong social opposition, this is good news. They can focus on the development of transmission in less sensitive regions. Finally, when not investing in transmission, the system relies more on (local) solar which, in turn, may trigger the need for more storage, as we will see in the next subsection.

3.2. Energy storage companies

Next, we will first analyze the total storage needs, followed by the implications for each storage technology. The figures used in this section are similar to Fig. 3 shown above. They all plot the same solutions (spheres) on the same dimensions (axes), but with a different color code for the necessary power capacities: total storage in Fig. 4, battery energy storage systems (BESS) in Fig. 5-a, pumped hydro storage (PHS) in Fig. 5-b, and hydrogen systems (H_2) in Fig. 5-c.

In the presence of flexible hydropower (hydropeaking) and a strong new transmission system, storage systems are less needed. Here our multi-objective optimization reflects existing knowledge. This is shown in the upper-right part of the Pareto Front in Fig. 4 by the black spheres. In this area, the total storage requirement is about 29 GW of power capacity. As we move to regions with more limited transmission, the

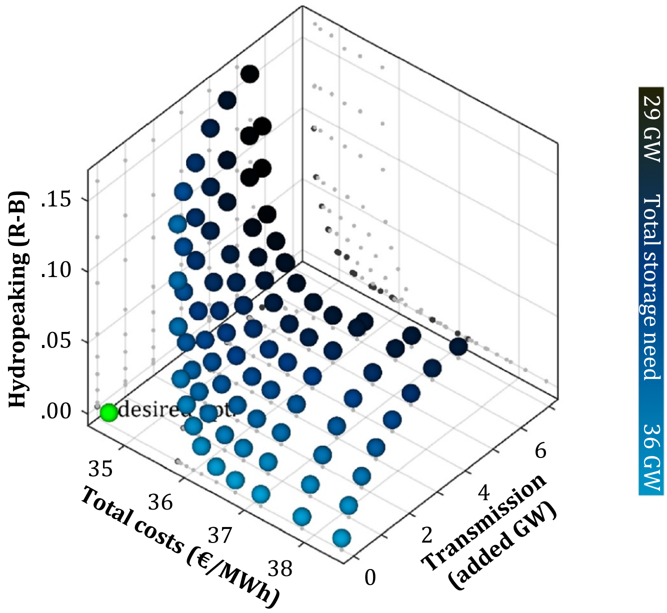

Fig. 4. Total energy storage capacity (GW) requirements.

need for storage increases strongly. Also, when hydropeaking becomes very constrained, the total storage demand grows systematically. When both sources of flexibilities are absent, storage requirements peak at 36 GW. All futures rely on storage systems, which stands in high contrast to new transmission that can be avoided entirely (see the previous section). Furthermore, the changes along the whole solution space are very smooth, meaning that small variations in constraining transmission and hydropeaking generate small changes in total storage requirements.

BESS (Fig. 5-a) are least needed in scenarios with strong transmission and allowed hydropeaking, constituting around 24% of peak demand. As these flexibility sources become more constrained, BESS requirements proliferate, culminating at 44% (of peak demand). PHS sizes (Fig. 5-b) show to be constant for all scenarios. This relates to the fact that the model recommends deploying all the available (energy capacity) potential of PHS (and then, for this energy capacity, the converter size is optimized). This is in line with other studies, which also have reported PHS to deplete the whole potential (Cebulla et al., 2017). H_2 (Fig. 5-c) exhibits only small variations of its recommended power capacity: between 44% and 46% of peak demand. Here, the main driver is the energy autonomy service (similar to fuel security) from the model. This long-term constraint is most easily met with H_2 storage. Note that providing this service also is the reason for the total storage capacities to exceed the peak demand; this can be seen equivalent to current power systems where peakers provide backup.

In summary, all futures rely on energy storage. BESS requirements grow when transmission and hydropower are more limited in direct response to lower levels of system flexibility, and also because those systems rely more on solar.

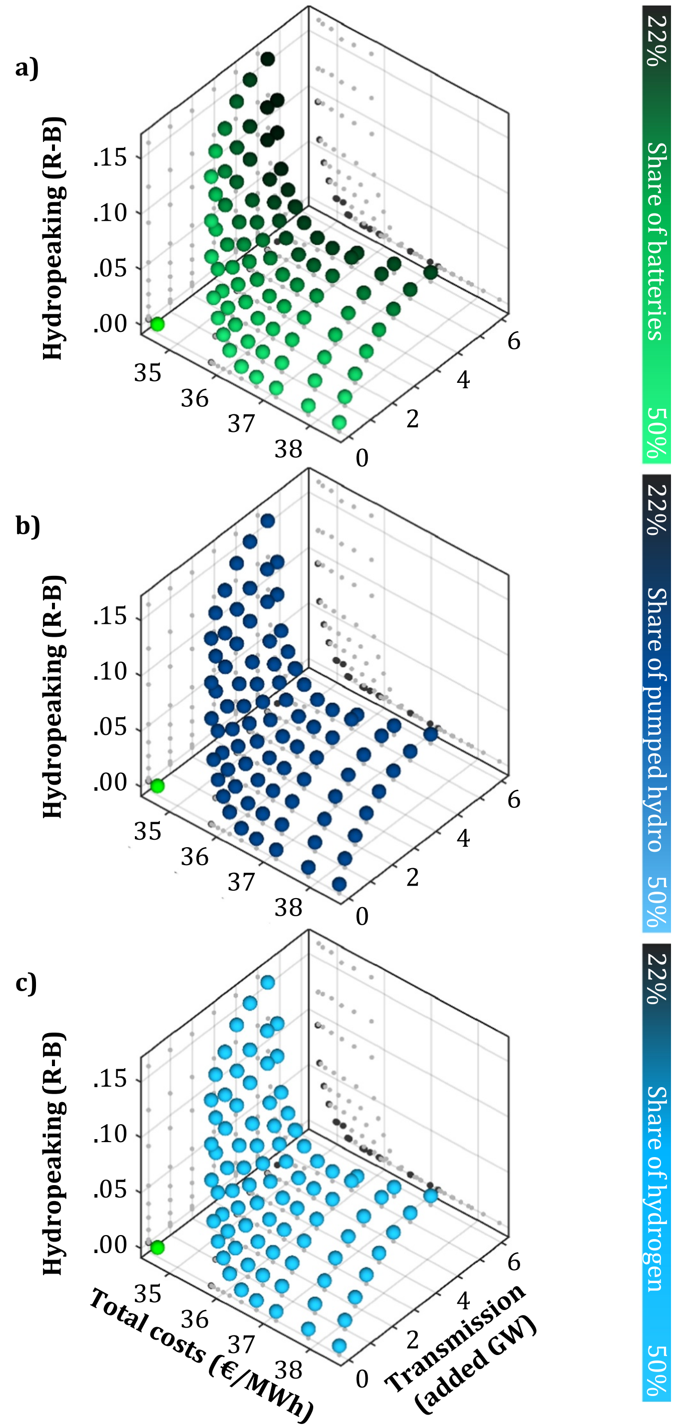

Fig. 5. Storage (power capacity) requirement per technology (normalized by peak demand). a) BESS, b) PHS, c) H_2.

3.3. Environmental organizations

Now, we will focus on how ecological alteration —in rivers downstream of hydropower reservoirs— can be mitigated. First, we will explore the tradeoff between transmission and hydropeaking, and then between costs and hydropeaking. Finally, we will identify a set of promising solutions in terms of all three considered dimensions.

For this section, we need to recall the shape of the Pareto Front from any of the above figures. Between hydropeaking and transmission, there is no *direct* competition. In fact, there is a solution where both dimensions are minimum. There, hydropower flexibility cannot be transferred to buffer the fluctuations of the zones strong in solar generation. All the remaining points (not Pareto-optimal in the dimensions of transmission and hydropeaking) are generated by the existence of the cost-dimension. It so happens that many solutions, especially for substantial transmission additions, rely on severe hydropeaking. There are also solutions, which keep hydropeaking close to the natural flow regime no matter the level of added transmission. It is all a matter of costs. However, under budget constraints, avoiding hydropeaking and transmission do compete.

To reach a flashiness close to the natural regime, a reduction of hydropeaking by one order of magnitude is needed (our base case exhibits an RB ~ 0.160, and natural streams can have values between 0.005 and 0.050 (Haas et al., 2015)). As the natural flashiness is different for each basin, we can only provide a first number in the direction of restoring the natural flow regime (and no final recommendation). RB values below 0.01 cost from 1%. The most extreme is targetting RB values close to zero, which has costs starting from 7% if transmission is present, and up to 11% if transmission is not.

An interesting solution region is where both hydropeaking and transmission are small but not zero. Having hydropeaking *close* to the natural regime (e.g. RB < 0.01), while investing only little (< 1 GW) transmission costs 3%. Avoiding the last GW of transmission costs another 1%. Very low values of hydropeaking generate the cost increase of 11% that we just mentioned in the previous paragraph. For this region (recalling Fig. 3 about the generation mix), the optimal system of 2050 will be based mostly on PV, with strong back up from BESS. From a technological point of view, what exact solution from that region is finally chosen does not seem to matter as the Pareto Front is smooth. Even if the flashiness tends to zero, the storage mix remains stable. This solution-robustness is practical when negotiating with the other stakeholders.

Two paragraphs earlier, we mentioned that transmission and hydropeaking could compete, which becomes relevant only under very constrained budgets (< 3%). Here, we can observe two extreme scenarios: low hydropeaking (RB = 0.01) while avoiding most (85%) transmission, or extreme hydropeaking while avoiding all transmission. Nevertheless, constraining the budget to such low limits seems somewhat unreasonable in the light of the potential benefits of mitigating both hydropeaking and transmission for one additional percent. A previous study showed that using BESS for peaking purposes, thus, reducing hydropeaking, can easily be profitable already in 2025 (Anindito et al., 2018). In other words, a clear investment strategy in solar and storage technologies (mainly BESS) is needed as soon as possible for reaching low values of hydropeaking and —at the same time —transmission.

To conclude, the main messages for environmental organizations are the following. Severe hydropeaking can be avoided for little costs (1%). If both transmission and hydropeaking are to be avoided, the cost increases by around 11%. This is enabled by affordable solar and storage systems. Communicating this link clearly (solar and storage allow avoiding hydropeaking and transmission) to society might help create a future based on strong solar and storage technologies (i.e. easier to tolerate).

3.4. Comments about uncertainties and future work

In the present work, we derived the tradeoff curves between total costs, hydropeaking, and new transmission infrastructures, when planning a fully renewable power system. The two latter are subject to deep uncertainties, which is why we treated them as separate dimensions, as opposed to modeling them as given hard-constraints. But there are other sources of uncertainty that we did not address, as briefly discussed below.

Regarding the reliability of the proposed solutions; recall that reliability has two components: adequacy ("ability to meet peak demand over time" (Martinez Romero and Hughes, 2015)) and security ("ability to withstand contingencies" (Martinez Romero and Hughes, 2015)). The former was taken care of endogenously by considering hourly nodal power balances. The latter we treated by requesting ancillary services (power reserves to tackle forecast errors of renewables; and energy autonomy to cope with longer periods of low renewable production), which also are modeled endogenously (Haas et al., 2018a). These services are still not an explicit treatment of contingencies but serve as a proxy. If further verification is desired on the secure operation of the solutions (e.g. with *n-1* simulations), the numbers from Table 2 in the appendix, showing the main component sizes, can be used.

In expansion planning exercises, cost assumptions are an inherent and important source of uncertainty. For solar PV and wind, cost projections are widely available, reducing the involved errors. However, batteries and, even more so, hydrogen systems are more incipient with correspondingly large deviations to be expected between their cost forecasts and actual future costs. For this reason, we decided to quantify the uncertainty of the most extreme scenario of our Pareto Front (the solution without new transmission and hydropower flexibility that resulted in the largest storage demand). For this purpose, we performed a Monte Carlo simulation, varying the investments costs of batteries, pumped-hydro (which we decided to include given their large cost spread across projects), and hydrogen system.[2] From Fig. 6(a), we

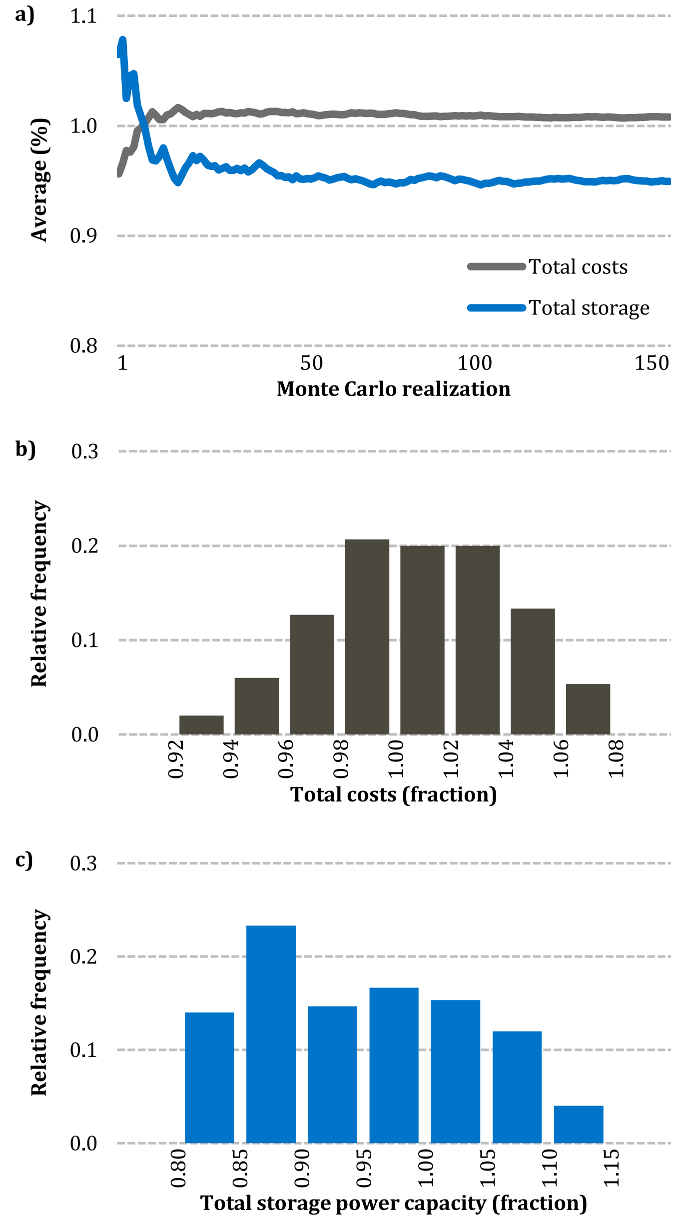

Fig. 6. Uncertainty quantification of results. a) Convergence of Monte Carlo. b) Distribution of total energy costs. c) Total storage power capacity.

[2] For lower and upper bounds of battery costs (energy and power capacities), we used the *high development* and *low development* scenarios from Breyer et al. (2017) adapted to 2050 based on Kilickaplan et al. (2017). For hydrogen systems, we varied the power capacity cost by ± 50% (relative to our originally assumed inputs) for all components except for the already-mature gas turbine (the energy capacity costs for methane storage was kept constant for the same reason). For pumped hydro, we assumed a cost range of ± 10% for the power capacity. We assumed an independent uniform distribution for each cost input, and ran 150 simulations with Latin Hypercube Sampling.

see that the total costs and total power capacity of storage converge after about 50 Monte Carlo runs. What we found is that the different storage investment cost can impact the total system costs by ± 8%, and the recommended total storage power capacity by −20 to +15% (relative to our selected scenario). These ranges, in the context of the wide range of investment cost considered, seem rather small. Most importantly, all scenarios from the Monte Carlo simulation have no unserved energy and present only small levels of curtailment (< 3%). In short, the uncertainty from storage investment costs on the resulting total storage requirements is limited, in our setup.

In terms of hydropeaking mitigation, we found that total costs are sensitive when the (system-wide) hydrologic flashiness index approaches values close to zero. What precise value we should target is not entirely clear, because we condensed all rivers into one single index and, in practice, each basin has a different natural flashiness. Also, from an environmental perspective, further dimensions could be included in the future, such as mineral sufficiency, life-cycle emissions (Moreno-Leiva et al., 2017), and land use.

Concerning our planning approach, we designed one milestone year (static planning). However, in practice, systems evolve gradually. This implies that past decisions might burden the future configurations, which in turn makes it more difficult to actually achieve the theoretical optimum. In this context, our found costs could be understood as lower bounds.

Market feasibility of the recommended solutions is another topic for the future. In general, the discussion of pricing mechanisms in fully renewable systems is very complex and incipient. Future power/storage companies will probably rely on incomes besides the energy market, for example from reserve markets or fuel security services. Even the energy market itself could suffer changes, evolving, for example, from marginal pricing of short-term costs to marginal pricing that include long-term costs (investment signals).

4. Conclusions and policy implications

In this work, we developed a multi-objective framework for finding an optimal storage and renewable generation mix. We considered three criteria in the optimization, but more could be included. A first criterion considered was minimizing investment and operational costs of the power system. A second criterion referred to the environmentally friendly operation of hydropower reservoirs. Their extreme peaking was shown to be harmful to downstream ecosystems; thus, here we minimize the flashiness of the existing hydropower park. A third and final criterion aimed to minimize additional transmission systems as these are plagued by delays and cost overruns, frequently related to social opposition. In a case study that focuses on Chile in the year 2050, we illustrated the resulting tradeoffs between these three dimensions for a 100% renewable power supply.

From a traditional cost perspective only, the optimal storage mix is composed of PHS, BESS, and H_2 by shares of around 30%, 25%, and 45%, respectively, with a generation mix that has a solar-to-wind ratio of about 1.8. However, the system also relies on at least doubling the transmission lines and a severe ecological flashiness coming from hydropower plants. Once taking into account the other dimensions during the optimization, we could identify the following implications for the involved stakeholders of a power system:

- Storage companies: Compared to the pure minimum cost solution, the need for storage grows (up to 20%) when transmission and hydropower are more limited. This requirement is met by deploying more BESS, while PHS and H_2 remain quite constant in most scenarios. In short, storage companies celebrate if either (or both) transmission or hydropeaking are constrained.
- Transmission and generation companies: Additional transmission can be avoided for little economic effort; avoiding 30% of new transmission comes at almost no cost (< 1%), and renouncing to all new transmission shows costs starting from 3% (depending on the level of hydropeaking). This is good news for planners and policymakers as they can concentrate on the development of transmission in less sensitive regions only. However, the upside for transmission companies is little. When additional transmission is constrained, the system relies more on local solar and storage. It is interesting that avoiding only 30% of transmission already creates a strong impulse towards solar generation. Possibly, both solar and storage companies will lobby against fully deploying transmission.
- Environmental organizations: Severe hydropeaking can be avoided for little extra cost (1%) if transmission helps in providing flexibility. If both transmission and hydropeaking are to be small, the cost increases are still limited (3%). The most extreme scenario is forbidding both; costing up to 11% more. Affordable solar and battery systems appear to be the key enablers for achieving systems without hydropeaking nor new transmission facilities at such little extra costs. Environmental organizations cheer.

In terms of future work, we identify the need for pathway planning (as opposed to static planning), as well as addressing the market feasibility of the recommended solutions. Furthermore, life-cycle emissions should be included, even for planning 100% renewable power systems, especially when needing to become carbon neutral or negative. In terms of externalities of hydropower, there are other aspects (e.g. social opposition) that may influence the deployment of new projects, and these should be looked at in the future. Also, the ecosystem impacts from hydropower could be detailed further.

Altogether, the implications for policymakers are the following. Stronger rules for preserving sensitive freshwater systems below hydropower dams can be enforced at little cost. In parallel, new transmission projects can also be avoided for a small additional economic burden. This is enabled by the very affordable (future) capital costs of solar and storage technologies, on which these solutions rely, for which a clear investment strategy is needed. Perceiving solar and storage systems as a mitigation measure to prevent hydropeaking and transmission could collaterally decrease the potential social opposition to storage technologies. The outlook for transmission companies might be cloudy, but solar generators, storage companies, and policymakers —and the fish— are looking forward to 2050.

Acknowledgments

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Appendix

See Table 2

Table 2
Main investment decisions per zone of extreme scenarios. Numbers shown in GW (GWh in brackets).

Scn.	Component	Zone 1	Zone 2	Zone 3	Zone 4
Max. transmission Max. hydropeaking	BESS	–	–	0.4 (1)	6.5 (39)
	PHS	3 (60)	3 (60)	1.8 (40)	1.8 (40)
	H_2	3.5 (2k)	2.4 (2.5k)	3.9 (0.8k)	3.2 (1.9k)
	Hydro (existing)	3.1 (9.8k)	3.1 (3.4k)	–	–
	Wind	9.4	0.0	13.4	4.1
	PV	0.0	22.4	7.8	19.4
	Transmission		L12: 2.3	L23: 3.2	L34: 0
Zero transmission Low. hydropeaking	BESS	–	4.8 (27)	–	6.7 (40)
	PHS	3 (60)	3 (60)	1.8 (40)	1.8 (40)
	H_2	2.2 (1.3k)	5.2 (5.3k)	3 (0.7k)	2.4 (0.9k)
	Hydro (existing)	3.1 (9.8k)	3.1 (3.4k)	–	–
	Wind	6.0	7.5	9.5	3.6
	PV	2.5	30.0	3.4	20.0
	Transmission		L12: 0	L23: 0	L34: 0
Max. transmission Max. hydropeaking	BESS	–	–	1.2 (4)	6.7 (40)
	PHS	3 (60)	3 (60)	1.8 (40)	1.8 (40)
	H_2	4.2 (3.2k)	1.9 (2.3k)	4 (0.9k)	3.1 (1.9k)
	Hydro (existing)	3.1 (9.8k)	3.1 (3.4k)	–	–
	Wind	10.2	0.0	16.7	4.1
	PV	0.0	18.8	10.9	19.8
	Transmission		L12: 1.8	L23: 5.2	L34: 0
Zero transmission Zero hydropeaking	BESS	–	6.1 (35)	–	6.7 (40)
	PHS	3 (60)	3 (60)	1.8 (40)	1.8 (40)
	H_2	4.3 (3.1k)	4.6 (5.7k)	2.2 (0.6k)	2.2 (1.4k)
	Hydro (existing)	3.1 (9.8k)	3.1 (3.4k)	–	–
	Wind	8.4	9.3	9.1	3.6
	PV	2.9	30.0	4.2	20.1
	Transmission		L12: 0	L23: 0	L34: 0

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