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The value of network investment coordination to reduce environmental externalities when integrating renewables: Case on the Chilean transmission network

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ABSTRACT

The need to decarbonize the power sector through increased participation of renewable generation has originated an escalating necessity for transmission network investments that can be undertaken by a number of market participants, including planning authorities/system operators, network companies and project developers. The expansion of the power network, however, presents various environmental and social conflicts, in particular, with land uses that are valuable by society such as the presence of communities, national parks, protected forests, tourism zones, archaeological sites, etc. In this context of environmental and social awareness, we assess the benefits of two strategies that coordinate network investments among various participants and compare them against the current counterfactual approach, where no coordination is undertaken and thus renewable generation projects are connected to the main transmission system in an individual, project-by-project basis. Through various case studies based on the main Chilean transmission system, we show that the lack of coordination in network investments may present severe impacts in terms of the socio-environmental externalities of transmission network expansions. Furthermore, we demonstrate that attempting to reduce externalities of new network investments without proper coordination of new developments may significantly limit the success of a land use policy associated with network developments.

1. Introduction

The increase in transmission network investments envisaged to integrate renewables can significantly conflict with various land uses that are valuable by society such as the presence of communities, national parks, protected forests, tourism zones, archaeological sites, etc. Historically, there are several examples around the world that illustrate the disadvantages of these conflicts (e.g., Beauly-Denny line in the UK (Tobiasson and Jamasb, 2016), Grain Belt Express in the US (Cardwell, 2016), HidroAysén transmission line in Chile (Astorga and Urquiza, 2013)), resulting in social and public opposition (Komendantova and Battaglini, 2016) that ultimately leads to severe delays and cost increases due to long negotiation processes with communities and reroutings of the planned power transmission lines (Bailey and Devine-Wright, 2014).

In order to limit the effects of these conflicts, regulators and network investors may apply advanced siting and routing methodologies such as EPRI (EPRI, 2006), ERPA (Araneo et al., 2015), OPTIPOL (Bevanger et al., 2014), National Grid (National Grid, 2012). These methodologies, that are based on multi-criteria decision analysis (MCDA) and geographical information systems (GIS), are fundamentally designed to identify preferable routes of power transmission lines that have already been decided to be built (Dedemen, 2013; Husain et al., 2012; Uzoukwu, 2010; Schmidt, 2009; Williams, 2003; Goodrich-Mahoney et al., 2004). At the network planning and investment stage (when a line is being decided whether to be built or not), however, very little has been done to limit externalities and this opens up opportunities to improve network regulation. In fact, if externality costs were properly anticipated and considered in the transmission expansion planning problem, they could even change the ultimate set of new lines to be built (Shu et al., 2011; Oudalov and Reza, 2007).

An important aspect that compounds the problem complexity associated with network investments and their externalities is the partially decentralized decision making process associated with new

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transmission network investments. Indeed, there are various regulatory regimes in transmission networks that permit the co-existence of both centralized planning of part of the network infrastructure (usually the main part associated with the national transmission system) and decentralized, market-driven network investments (usually associated with new lines built by project developers to connect their generation to the main system). Evidently, decentralized network investments can, if they are not properly regulated, significantly increase the number of new lines being built, which can clearly conflict with the environment. On the contrary, as explained in Strbac et al. (2014), several project developers might coordinate their investments and plan a single power line to connect their aggregated power to the main transmission system, capturing the economic benefits of the coordination and mitigating the environment externalities. This is particularly important in the context of the numerous renewable energy power plants that are expected to be integrated in the coming years (Holtkamp and Davidson, 2010).

In the presence of decentralized, market-driven network investments, coordination among network investors will be paramount. The benefits of network investment coordination among regimes and participants have been already studied in (Konstantelos et al., 2017), which demonstrated that coordination of network investments can result in a benefit as large as €80 billion in the North Seas (in the period 2020–2044) if the various network investments were coordinated among participants. Furthermore, reference Konstantelos et al. (2017) proposes to build an entire grid to connect offshore wind projects (and countries) among themselves in the North Seas rather than to connect them to shore in an individual, project-by-project basis.

To capitalize on network investment coordination, network regimes need to be regulated accordingly.[1] For example, the offshore transmission network in the UK, that was originally built by offshore wind developers to connect their projects to shore, is now owned by different offshore transmission companies (namely offshore transmission owners, i.e. OFTOs) following the divestment process of network assets started in 2009. Furthermore, the design of offshore networks in the UK is currently undertaken by the national System Operator (SO). Reference Strbac et al. (2014) discusses the benefit associated with an Independent System Operator (ISO) who coordinates the transmission investments across various regimes (onshore transmission, offshore transmission and cross-border interconnections) and participants (including generation project developers). In the US and South America, there have also been various initiatives to coordinate transmission investments and thus facilitate the integration of renewables. For example, ERCOT (the ISO in Texas) has defined various Renewable Energy Zones (REZ), where transmission investments are undertaken in anticipation of renewable generation projects, in a proactive manner as defined in Sauma and Oren (2006), aggregating the future needs for new network capacity and hence capitalizing on the economies of scale of transmission (Lee et al., 2017). In Brazil, special network infrastructure, namely *collector substations* (Moreno et al., 2010), has been planned and built to coordinate the integration of various projects at the time. In a similar vein, Chilean authority has recently issued a new Act (Ley 29.936 (Chilean Energy Ministry, 2016)) in 2016 to facilitate the integration of renewables through special Renewable Energy Zones, expanding on Texas' experience.

An important feature of these initiatives is that the focus is on the economics (and speed) of renewables integration. Externalities associated with network investments necessary to undertake such integration are, as explained earlier, frequently left for a second stage of the planning process, once network expansions (i.e., new power lines) have been already decided. In this paper, we consider land use externalities as part of the first stage of the planning process, where decisions about the set of lines to be built and the topology of the transmission network are being made. In this context of early environmental and social awareness, we assess the benefits of two coordination strategies that optimize network investments among various participants and compare them against the current counterfactual approach, where no coordination is undertaken and thus renewable generation projects are connected to the main transmission system in an individual, project-by-project basis. Through various case studies based on the main Chilean transmission system, we show that the lack of coordination among network investments across several regulatory regimes, may present severe impacts in terms of the socio-environmental externalities of transmission network expansions. Furthermore, we demonstrate that attempting to reduce externalities of new network investments without proper coordination of new developments may significantly limit the success of a land use policy associated with network developments. We justify our results through a novel mixed integer linear program (MILP) that optimizes transmission investments considering various levels of coordination among market participants.

The remaining of this paper is organized as follows. Section 2 describes the method of analysis and the mathematical model used for our quantitative assessment, including the input data used for the Chilean case study. Section 3 shows the numerical results and discusses the impacts of network investment coordination on the optimal transmission expansion plan when land use externalities are taken into consideration. Finally Section 4 concludes, identifying key regulatory and policy implications.

2. Methodology

2.1. General description of the model

We aim to study the impacts of coordination strategies of new transmission investments from a socio-environmental point of view when integrating new generation. In particular, we focus on the land use externalities of the necessary network infrastructure that serves to integrate coming renewable generation. To analyze the impacts of coordination, we define various case studies inspired in the integration of the vast hydro potential in the Chilean electricity system by 2050. To do so, for a given installed capacity of generation in the future, we optimize investment decisions in the electricity transmission network in a cost minimization framework, considering the socio-environmental costs (or land use externalities) associated with new infrastructure investments located where land currently presents further valuable uses (national parks, social communities, etc.).

Hence, we use a cost-minimizing 2-stage stochastic mixed integer linear program that can determine optimal transmission expansions at a national level for a given set of future generators and considering various hydro scenarios in a stochastic fashion (i.e., inflows). In this framework, the model determines optimal network assets, minimizing the total cost, which is composed of network investment costs, system operating costs (which is stochastic, so we consider the expected value across various hydro scenarios), and socio-environmental cost. One of the unique features of our model is that the geographical location of existing and new electricity infrastructure is recognized, which allows us to assess appropriately the impacts of the new infrastructure on current land uses. Importantly, land uses (considering Valuable Objects [VO] located nearby candidate transmission assets) are also mapped and geographically recognized in our model.

Hence, the overall objective function of the model is composed of:

- Monetary costs, with 2 cost components:
  - o Transmission investment cost, which is associated with the cost of new electricity infrastructure
  - o Operational cost, critical to assess the cost savings in operational timescales to run the electricity system; to do so, we need to

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[1] Notice that although coordination may benefit market participants (since the overall cost of new network infrastructure is reduced), they need support from regulation due to, among other reasons, transaction costs (Strbac et al., 2014; Milgrom, 2017).

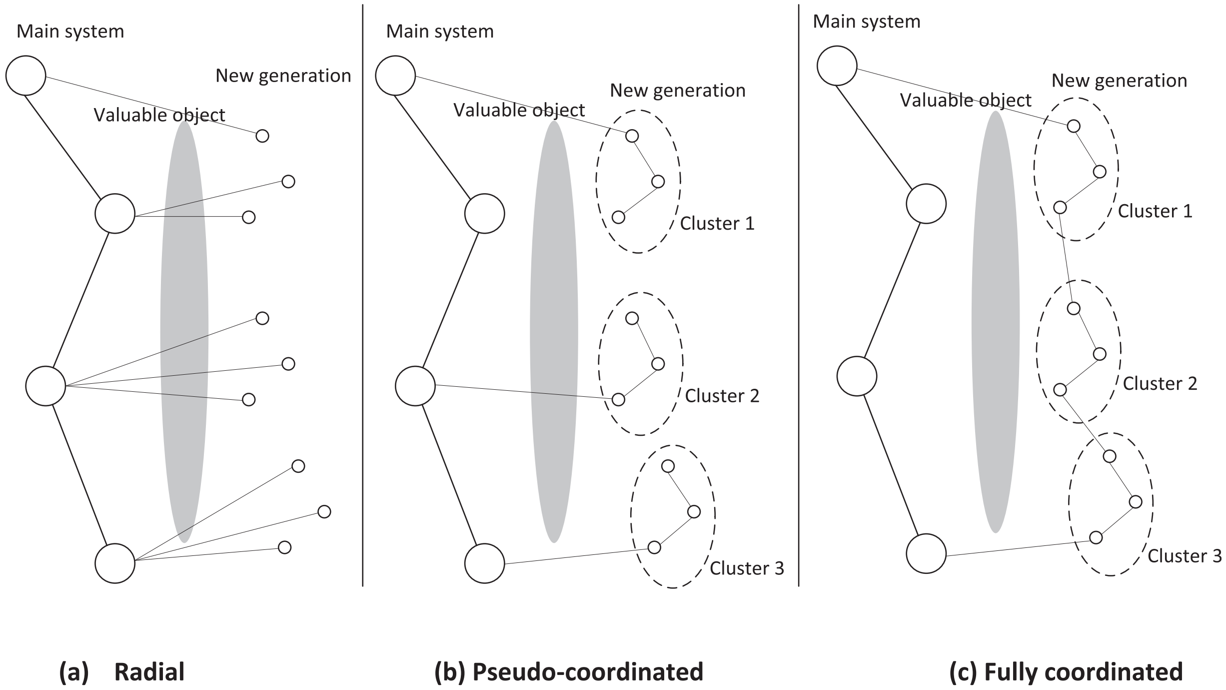

Fig. 1. Coordination strategies of network investment. (a) Radial (b) Pseudo-coordinated (c) Fully coordinated.

model the system operation which is done in a stochastic basis, considering 5 hydrological scenarios; we also consider a number of operating conditions that represent combinations of demand, wind and solar power levels across a year.

- Socio-environmental cost: through penalty factors on the investment cost, escalating the cost of candidate infrastructure so as to represent the socio-environmental impacts or land use externalities of new power lines.

As mentioned earlier, it is of particular interest to understand how network investments can be coordinated among generation project owners (and transmission owners) to reduce the impact of new infrastructure on the environment. Hence, we analyze three different strategies for coordinating investment decisions among market participants (See Fig. 1):

(i) *Radial, decentralized strategy (counterfactual, no coordination)*: Where each new generation project owner builds a direct, "radial" line to the main electricity system without coordinating with further parties (so the line capacity is fitted for the necessities of a single project only) and without considering, as a landing/access point, existing substations[2] that are privately owned by other generators. This strategy represents the lowest coordination level.
(ii) *Pseudo coordinated strategy (coordination at a local level):* Where a group or cluster of new generators located nearby coordinates to build a shared transmission infrastructure (composed of lines and a "collector" substation) and therefore connects to the main system through a single transmission line. As points of landing/access, all substations nearby are considered, except for those that are owned by other, existing generators.
(iii) Fully coordinated strategy (coordination at a global level): Where all new generators are fully coordinated to interconnect among themselves and consider all available options as a landing substation, except for those owned by other, existing generators. This strategy represents the highest coordination level.

One important feature of our model is that it optimizes the topology configuration of new lines and not their exact sitting (in fact, we assume straight lines in this early stage). For instance, if a given line (needed to connect a new hydro plant) imposes significantly high socio-environmental costs, the model can choose to build an alternative line that avoids crossing valuable land uses that may conflict with the development of the new transmission line. Hence, the model represents an early stage of the planning process, prior to sitting, identifying optimal topology configuration of new investments while considering land use externality costs.

In optimization terms, our transmission investment model can be summarized as in Table 1 (see full mathematical formulation in the Appendix), where the coordination-type constraints indicated at the end of Table 1 refer to those that prevent investment in all possible candidate lines, reassembling (i) the radial case (where constraints allow only radial connections), (ii) the pseudo coordinated case (where constraints allow internal connections within a cluster), and (iii) the fully coordinated case (where the coordination-type constraints are fully neglected to allow investment decisions in all candidate lines).

Notice that although the model represents a single planning authority optimizing all transmission investments in the future by minimizing total costs, under traditional economic assumptions, the model also represents the long-run market equilibrium where decisions are undertaken by various private parties (Muñoz et al., 2017). Therefore, through implementation of points (i)–(iii) [the three different strategies for coordinating decisions in network developments] as constraints of the cost-minimizing problem, we aim to "emulate" what would happen in the long-run equilibrium, if transmission investment for new generators is coordinated at different levels.

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[2] The transmission network is divided into 3 categories or regimes in the Chilean system: national or trunk (dedicated to transfer power at the national level), zonal or subtransmission (dedicated to transfer power at a more local level, i.e., from the trunk system to distribution system), and dedicated or additional network (dedicated to connect either generators or private, large consumers to the rest of the system). Generally speaking, the owners of national and zonal systems are network companies, while the owners of dedicated systems are generation companies.

Table 1
Structure of our proposed 2-stage stochastic mixed integer linear program for network investment.

Minimize {transmission investment cost + system operation cost + socio-environmental cost}
Relevant decisions variables: ● Network reinforcements through continuous variables that increase capacity of existing assets ● New lines through both binary variables and continuous variables (to recognize both fixed and variable cost per new line) ● Generation dispatches and power transfers Subject to: ● Energy balance constraint per node, per time period, per inflow scenario ● Maximum generation capacity constraint per generator, per time period, per inflow scenario ● Maximum hydro production per season, per hydro generator, per inflow scenario ● Power transfer constraint per line, per time period, per inflow scenario ● Coordination-type constraints

2.2. Case study

The proposed optimization model is applied to the Chilean electricity system, which includes the current central transmission system, namely SIC (Central Interconnected System), and the northern transmission system, namely SING (Norte Grande Interconnected System), which are interconnected since this year. Here, we attempt to integrate the full hydro potential to the national power system, which is expected to occur by 2050.

We run several case studies that aim to understand how network investment can be coordinated among generation project owners to mitigate the associated externalities, i.e., impact of new infrastructure on the socio-environmental valuable objects. This requires also understanding of monetary cost increases due to the reduction of environmental impacts. To do so, we compare:

- The system expansion for various levels of coordination, and
- The system expansion with and without consideration of socio-environmental costs

2.3. Main input data

2.3.1. Generation capacity

We consider future generation according to the Energy Roadmap 2050 elaborated by the Chilean Energy Ministry (Chilean Energy Ministry, 2015). Table 2 shows the capacity generation levels in Chile by 2050 per technology and the variable costs used to determine system operational cost across a year. Also, we consider integration of the full hydro potential presented in Table 3 and Fig. 2 (and obtained from PUC-TECO-UCH (2016)), where Patagonia has been removed as a source of hydropower generation. Fig. 2 shows the blue dots associated with the hydro potential that will be integrated to the main electricity system. Each dot or hydro potential point is assumed to be a single unit and is part of one of the seven basins in the south of Chile. The generation capacity of each point corresponds to that of the so-called sub-subbasin, which is the smallest unit within a basin according to PUC-TECO-UCH (2016). In reality, though, there may be several projects related to one dot. Although generation capacity from further technologies might be installed by 2050 (apart from hydro), we focus on the location of hydro plants to illustrate and study the benefits of coordination strategies of new transmission investments from a socio-environmental point of view when integrating new generation. Importantly, potential hydro generation is located in areas that present very complex VOs such as indigenous communities and reserved

Table 2
Generation installed capacity by 2050.

Technology	Total capacity [MW]	Variable cost [US$/MWh]
Biomass/cogeneration	130	25
Geothermal	75	–
Wind	5411	–
Solar	3130	–
Run of the river	4244	–
Reservoir (existing)	3407	–
Hydro potential	10,890	–
Coal	5080	41
Natural gas / LNG	3864	64
Diesel	5631	146
Total	**41,862**	

Table 3
Hydropower generation potential per basin.

Basin	Capacity [MW]
Maule	1473
Biobio	3038
Tolten	1124
Valdivia	1646
Bueno	1389
Puelo	818
Yelcho	1403
Total	**10,890**

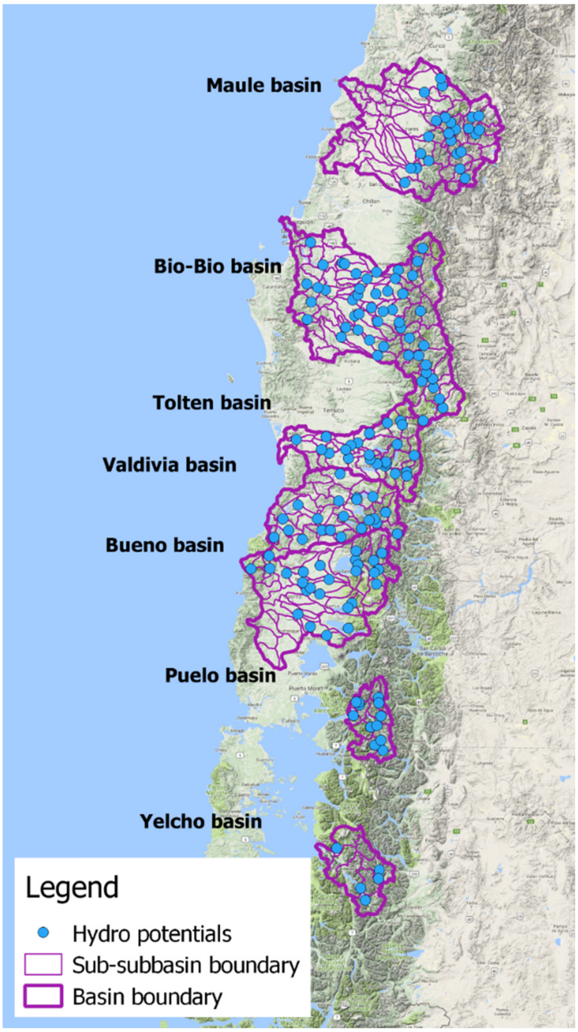


Fig. 2. Location of hydro potential per basin. (For interpretation of the references to color in this figure, the reader is referred to the web version of this article.)

national parks as explained later on, at the end of this section.

2.3.2. Operating scenarios: demand, solar, wind and hydro

We combine 10 levels (or scenarios) of demand, wind and solar power per season, and consider 4 seasons in a year (i.e., resulting in 40 operating conditions in a year). We select these 10 (normalized) operating conditions that are representative of a season by using k-means clustering, aiming to capture temporal and spatial correlations. The 40 operating conditions are combined with 5 hydro conditions (from very dry to very wet years, including an "average" year) so as to capture the variability associated with inflows. Thus, we represent a total of 200 operating conditions per year, which are used to quantify the operating costs related to network investment propositions. While wind, solar and hydro profiles are taken from DGF-UCH (2012a), DGF-UCH (2012b) and DGF-UCH (2014), demand profiles are taken from the system operator database published at CEN (2016).

2.3.3. Transmission system

The expansion of the transmission network considers both upgrade investments in existing links (also called reinforcements) and investments in new lines required to connect new hydropower generation to the main system.

2.3.3.1. Existing links. We use a simplified, representative Chilean transmission network that captures the main features of the national system (SIC and SING interconnected), considering 91 nodes and 116 links as explained next:

91 nodes:

- 90 SIC nodes
- 1 SING node

116 links (lines and transformers) in 5 voltage levels (500, 220, 154, 110 and 66 kV):

- 115 SIC → SIC links
- 1 SIC → SING link

The existing network infrastructure features a present, initial capacity (that represents actual transfer capability of the network infrastructure) that can be also reinforced towards 2050. We focus on SIC rather than SING area since hydro resources are only present within the SIC area.

2.3.3.2. New connections that change network topology. There are new lines that, if installed, would change the network topology configuration. These new lines are mainly installed to integrate new generation, which are represented by new nodes in the system. This is detailed next.

161 new nodes/substations for hydro power generation:

- 24 for Maule's hydro potentials
- 50 for Biobio's hydro potentials
- 23 for Toltén's hydro potentials
- 22 for Valdivia's hydro potentials
- 25 for Bueno's hydro potentials
- 12 for Puelo's hydro potentials
- 5 for Yelcho's hydro potentials

489 candidate new lines in 2 voltage levels (220 and 110 kV):

- 322 lines to connect new hydro power to SIC
- 135 lines to interconnect hydro potential points within a cluster
- 32 lines to interconnect hydro potential points in different clusters

2.3.3.3. Transmission investment (monetary) cost. Part of the model's objective function is the monetary investment cost of transmission associated with reinforcing and building new lines or transformers. These costs, detailed below, are divided into fixed and variable costs, and therefore we need a mixed integer linear programming (MILP) representation to separate the capacity volume decision (represented by a continuous variable) from the line entry decision (represented by a binary variable).

For lines:

- Fixed investment cost: which represents the annualized value of the investment plus maintenance and administration costs associated with substation equipment at the ends of a line. These costs are equal to US$ 2.68, 0.86 and 0.14 million for 500, 220 and less than 220 kV lines per year, respectively (all values consider N-1 security criterion).
- Right-of-way cost: equal to 7249 US$/km yr with a strip of 50 m wide.
- Variable investment cost: unit cost per MW of power and equal to 66, 124 and 146 US$/MW km yr for 500, 220 and less than 220 kV lines, respectively (all values consider N-1 security criterion, i.e., double circuit).

For transformers:

- Fixed investment cost: which represents the annualized value of the investment plus maintenance and administration costs associated with substation equipment and equal to US$ 1.78 million per year.
- Variable investment cost: unit cost per MW of power and equal to 2168 US$/MW.yr.

2.3.3.4. Socio-environmental cost or land use externality cost of transmission. We consider several socially Valuable Objects (VOs) such as communities, national parks, protected forests, tourism zones, archaeological sites, etc., georeferenced in the map. Although some VOs can be initially represented as a single spot/coordinate on a map, an impact area around this targeted spot can be defined. As stated in Komendantova (2018), it is important to emphasize that the selection of the VOs must be carried out based on participatory processes with inhabitants and different stakeholders, to jointly define land uses so that the process of planning assets (transmission lines in our case) can be truly successful. In this way, the regulator (or the proactive transmission planner) will be able to minimize opposition risks and thus achieve the planned benefits.

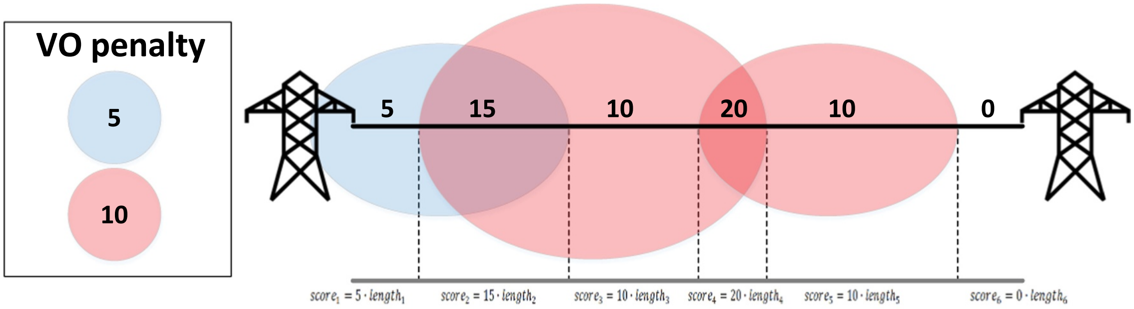
Examples of VOs that are relevant for the electricity infrastructure planning problem in Chile, are shown in Table 4.

Once areas representing VOs are identified on a map, we define penalty factors to recognize the "socio-environmental costs" of the new lines that are located in VO areas. In this analysis, we consider the same penalty factors for all VOs listed in Table 4 according to official sources

Table 4

Examples of VOs relevant for transmission planning in Chile.

Theme	Geographical information
Conservation	National parks and reserves Priority conservation sites Protected national assets Native forest Nature sanctuary
Natural environment	Vegetable formations
Tourism	National attractions Tourist interest zones
Agriculture	Areas of interest for the Chilean Agriculture Ministry
Planning	Towns Population centers
Property	Indigenous development zones
Patrimony	Archaeological sites



$$Total\ line\ length = \sum_{i=1}^{6} length_i$$

$$Weighted\ sum\ penalty\ factors = \sum_{i=1}^{6} score_i$$

Fig. 3. Representation of the impact of VOs in the investment cost of a transmission line.

of information published by the Chilean Energy Ministry (PUC-TECO-UCH, 2016). In future studies, each type of VO may consider a particular penalty factor so as to represent the preferences among various types of VO. The methodology proposed here illustrated is sufficiently general to handle this. Due to these penalty factors, the model will attempt to avoid locating new lines in these areas so as to minimize the overall cost function. In case a single line goes through various VOs, a weighted sum of penalty factors is calculated, as illustrated in Fig. 3. Socio-environmental costs are adequately normalized in order to make them comparable to monetary investment costs and these are calculated only for new connections. Accordingly, we ignore socio-environmental costs of existing assets in the main transmission system since the model does not modify the topology configuration of the existing network.

3. Results and discussion

Table 5 shows the network investment costs (including both main transmission system infrastructure and localized infrastructure) related to the (i) radial, (ii) pseudo coordinated, and (iii) fully coordinated network investment strategies. Results are obtained when minimizing both the network investment monetary cost and the socio-environmental (land use externality) cost associated with new lines (in addition to the cost of operating the power system, i.e. economic dispatch of generation, which is also considered in the minimization although not reported). The associated network topologies for these 3 network investment strategies are presented in Fig. 4.

Table 5 shows that (in expectation) full coordination leads to the highest benefits, capitalizing in cost savings of up to 21% with respect to the business-as-usual, radial case. As shown in Table 5 and Fig. 4, this can be explained due to important reductions in both reinforcement costs in the main transmission system and, remarkably, in the costs associated with new connections (the so-called new-point-to-main-system connections). On one hand, cost savings in new-point-to-main-system connections occur, as expected, due to a higher coordination level (since coordination precisely eliminates the need to connect projects to the main system on a case-by-case basis). On the other hand, cost reductions in the main system occur due to: (i) a more efficient and reduced set of landing points in the main transmission system (which is precisely the case in the pseudo coordinated strategy), and (ii) the creation of new loop flows, where new connections among hydro potential points (i.e., new-point-to-new-point and cluster-to-cluster connections) can provide additional “transfer capability” to the main transmission network (which is precisely the case in the fully coordinated investment strategy).

Table 5
Network costs in [millions US$/yr] associated with the 3 investment coordination strategies when minimizing monetary-investment and socio-environmental costs. Figures include both monetary investment cost and externality cost.

	Radial	Pseudo	Fully
Reinforcements in main transmission system	399	384	333
New-point-to-main-system connections	307	133	111
New-point-to-new-point connections (within cluster)	0	69	85
Cluster-to-cluster connections	0	0	27
Total	706	586	557

Furthermore, under the fully coordinated strategy, the network cost associated with new-point-to-new-point and cluster-to-cluster connections is significantly higher and these network assets can now support the main system to transfer increased energy levels without major reinforcements in the main system. In other words, new-point-to-new-point network assets and cluster-to-cluster connections do not only integrate the new hydro potential to the main system, but also support the main transmission system to transfer higher volumes of energy. Hence, despite the increase in new-point-to-new-point and cluster-to-cluster network costs, there is an important drop in reinforcement costs at the main transmission level that, in turn, decreases total network investment costs.

Notice that the two-fold purpose of new connections in the fully coordinated strategy ([i] provision of higher levels of access for hydro integration and [ii] higher transfer capability in the main system) has an important implication in network remuneration since, if cost-reflective network tariffs are in place (i.e., if a cost allocation like beneficiary-pays applies (Hogan, 2011)), then new connections should not be entirely remunerated by new entrants like in the radial case. Clearly, under the fully coordinated strategy, there will be beneficiaries among existing generators (already connected to the main transmission system), who will take advantage of the higher transfer capability at the main transmission level, provided by new meshed connections (i.e., new-point-to-new-point and cluster-to-cluster connections). In this context, new-point-to-new-point and cluster-to-cluster connections should be remunerated by both new entrants and incumbent generators, providing incentives for coordination among incumbent and existing generators. In Chile, unfortunately, cost-reflective transmission network tariffs were derogated under a new Act issued in 2016 (Ley 29.936 (Chilean Energy Ministry, 2016)), which mandates the recovery of network investment costs mainly through demand charges. In this context, incumbent generators present no incentives whatsoever to coordinate with new entrants to save in network reinforcement costs in the main system. Likewise, new entrants that develop the new connections do not perceive any benefit from proposing network solutions that may be more efficient at the main system level.

Consequently, in the absence of proper economic incentives, central

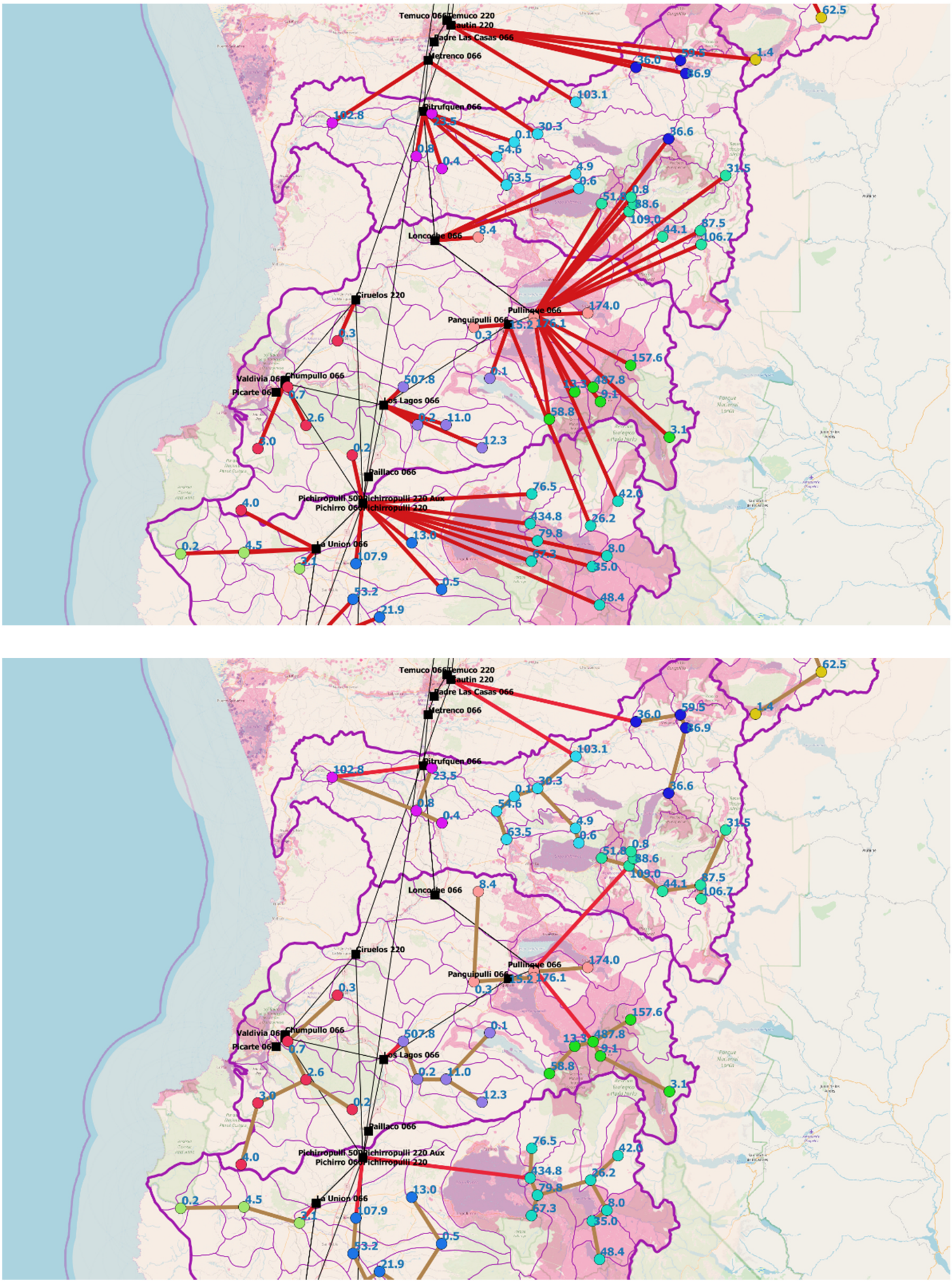


Fig. 4. Network topologies of the 3 coordination strategies (from top to bottom: radial, pseudo coordinated and fully coordinated). Square black points refer to substations, black lines refer to the main network infrastructure, circles refer to hydro potentials, circles' colors identify the cluster to which a hydro potential point belongs, lines' colors refer to network types (red for new-point-to-main-system connections, brown for new-point-to-new-point connections [within a cluster], and orange for cluster-to-cluster connections), and pink shadows refer to the penalization associated with land use externality (the darker the shadow, the higher the penalization). (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

planning may play a major role in coordinating new network infrastructure (among players and to provide wider benefits to the main transmission system). This, however, will need a proactive, system-wide transmission planner that can properly bear and compare the costs and benefits of main transmission system reinforcements against those derived from new connections, which can be located far from the main

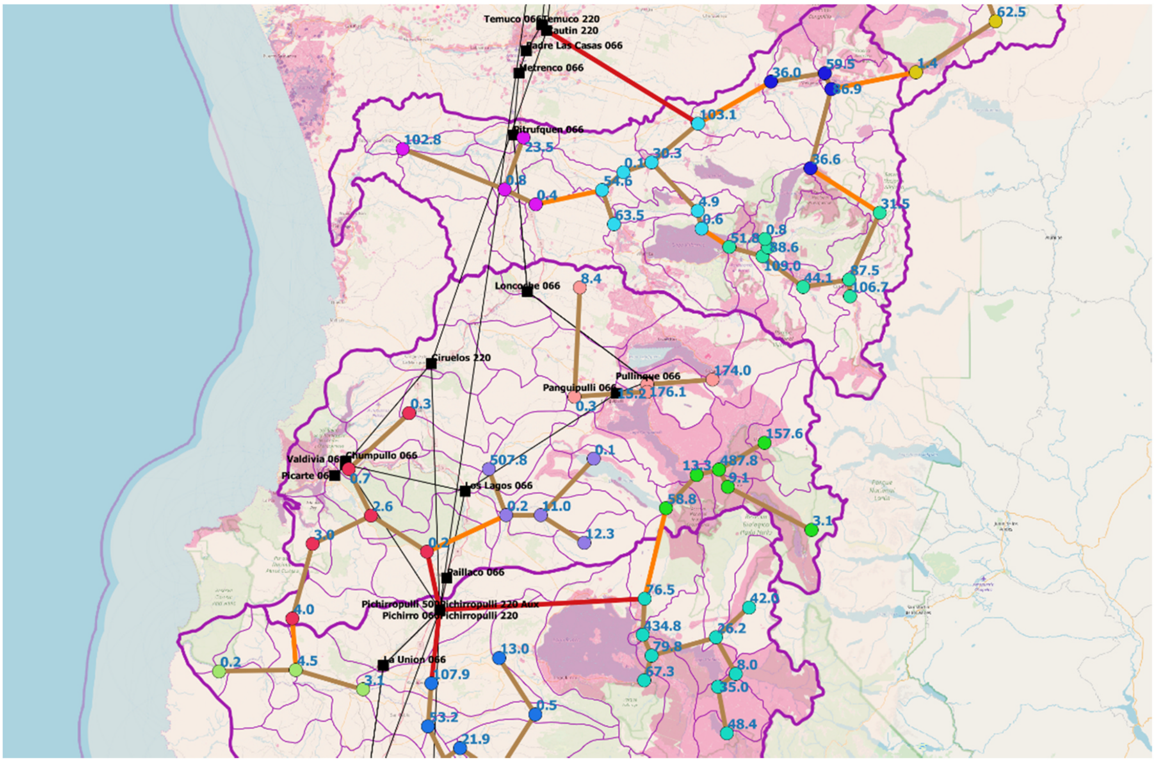


Fig. 4. (*continued*)

system.

Table 6 shows the monetary-investment costs and the socio-environmental costs of two investment solutions: one obtained when totally ignoring the effect of externalities (Case A) and one obtained when considering the effect of externalities (Case B). The former minimizes only the monetary cost of network investments while the latter minimizes both investment and socio-environmental costs. In Case A, we can assess the socio-environmental cost post optimization. As expected, coordination of future network investments leads to lower total cost under the three coordination strategies, namely, radial, pseudo coordinated and fully coordinated. Interestingly, more coordination does not necessarily leads to lower socio-environmental costs. For instance, (i) fully coordinated strategy presents the highest socio-environmental costs in Case A, and (ii) pseudo coordinated strategy presents the lowest socio-environmental cost in both cases. This fact highlights the relevance of jointly considering the players-coordination level and the socio-environmental externalities when planning the network expansion.

Table 6 also shows that externality costs are reduced when they are considered in the cost minimization. Furthermore, such reduction is the highest in the fully coordinated case since coordination opens up further opportunities for network planners to change and select the ultimate network topology. On the contrary, in the radial case, benefits of including externalities as part of the network expansion planning problem are very limited since the network expansion is too constrained to be radial, with no possibility to combine new network solutions that can create further alternatives for expansion. This is shown in Fig. 5 where topology changes between Case A and B are exacerbated under the fully coordinated strategy. In general, Fig. 5 shows how consideration of socio-environmental costs can lead to a different, improved topology, which truly minimizes the intersections between the new lines and VOs (including lakes and pinked areas).

It is worth to mention that, although cost differences in Table 6 are not too high (i.e., the solutions are similar in total, system-wide cost terms), solutions are significantly different in local terms, as shown in Fig. 5. This means that, while total costs are relatively similar among different cases, they lead to solutions with important differences in terms of new transmission lines in some localities.

Furthermore, costs differences in Table 6 might be higher in practice since transmission coordination drives not only those economic

Table 6

Monetary-investment, socio-environmental and total costs (in [Millions US$/yr]) of the three coordination strategies when ignoring and when considering externalities in the cost minimization.

		Cost [Millions US$/yr]	
		Ignoring externalities (Case A)	Considering externalities (Case B)
Radial	Monetary-investment cost	670.92	671.48
	Socio-environmental cost	35.26	34.54
	Total cost	706.18	706.02
Pseudo	Monetary-investment cost	554.52	555.87
	Socio-environmental cost	30.74	29.74
	Total cost	585.26	585.61
Fully	Monetary-investment cost	524.20	523.13
	Socio-environmental cost	39.54	33.47
	Total cost	563.74	556.59

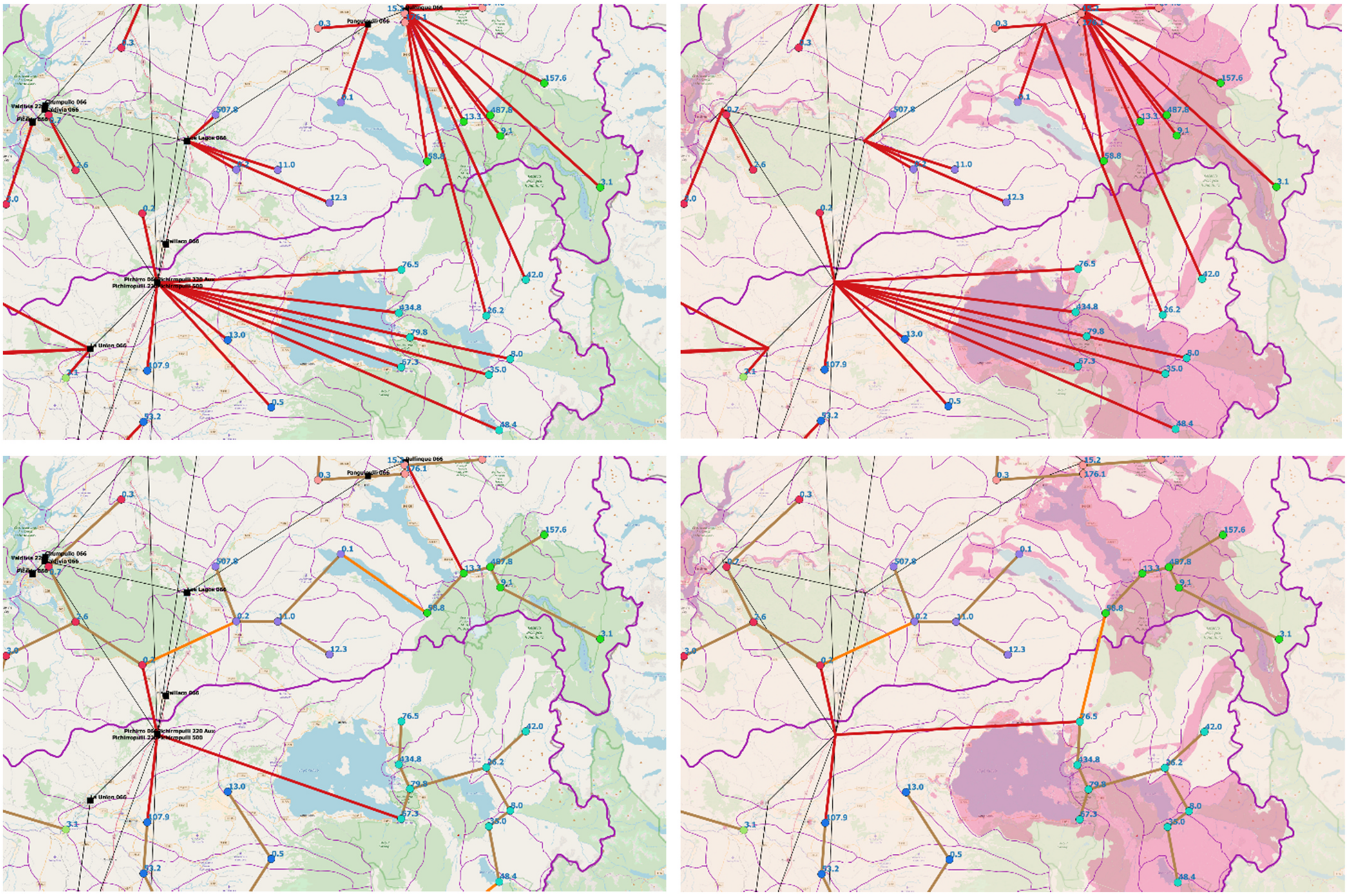


Fig. 5. Optimal network topology in the radial case (top) and fully coordinated case (bottom) when ignoring (left) and considering (right) externalities. Square black points refer to substations, black lines refer to the main network infrastructure, circles refer to potential hydro potentials, circles' colors identify the cluster to which a hydro potential point belongs, lines' colors refer to network types (red for new-point-to-main-system connections, brown for new-point-to-new-point connections [within a cluster], and orange for cluster-to-cluster connections), and pink shadows refer to the penalization associated with the land use externality (the darker the shadow, the higher the penalization).(For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

advantages calculated in this paper, but also improvements in the system reliability performance due to the more meshed network configuration (i.e. more loop flows in the system). This is an important technical aspect, as explained in (Strbac et al., 2016), that is not included in our costs figures.

4. Conclusions and policy implications

We proposed a framework to assess the benefits associated with coordination of network investments among new entrants (and also incumbent market participants) in terms of the saving in both investment costs and socio-environmental costs related to new network expansions needed to connect coming renewable generators. In this context, we presented optimal plans of new network investments needed by 2050 and used multiple case studies, inspired in the integration of the vast hydro potential in Chile, which might be needed in the future to provide flexibility services that can counteract the effect of intermittent renewables from sources such as wind and solar.

Through our assessments, we showed that coordination of new network infrastructure is paramount in the reduction of both network investment costs (21% reduction compared to the business-as-usual, radial case) and their land use externality costs. Furthermore, attempting to reduce externalities of new network investments without proper coordination of new developments may significantly limit the success of a land use policy associated with network developments. In a similar vein, we demonstrated that coordination by itself (without appropriate treatment of externalities in network plans) will not necessarily lead to a lower externality level and may even exacerbate the original externality problem. Hence, we claim that an appropriate land use policy needs to jointly consider both (i) costs/constrains associated with land use externalities in network plans and (ii) mechanisms to coordinate new network infrastructure among market participants.

In this context, we encourage network regulators to design:

1. appropriate mechanisms to recognize land use externalities from various network plans and determine the set of new expansions (internalizing externalities in the form of extra costs and/or constraints that can be identified through both socio-environmental studies and participatory, community-level planning sessions),
2. appropriate mechanisms for coordination of the needed network expansions, including:
   a. institutional arrangements to efficiently limit the scope of individual participants in network design, increasing that of the main system planner, and
   b. cost-reflective network charges that encourage coordination, and thus properly "guide" system expansions, which are consistent with allocating network costs to the true beneficiaries of the new investments.

Two elements that can limit the benefits of coordination are (i) failing to establish participatory processes to minimize the opposition risk associated with transmission investments and (ii) the presence of uncertainty. In the case of the latter, it is important to recognize that new entrants do not show up at the same time, and therefore, there will be (potentially significant) uncertainty levels associated to the timing of the decisions in network investment and the topology for new connections. Here, a major problem will be to allocate the cost of future beneficiaries among current beneficiaries and how the network planner will make anticipative network decisions without exposing users to either high risk of stranded assets or limited access capacity for future connections. In this case, planners will need to consider: (i) stochastic and/or robust, rather than deterministic, models as explained in (Munoz et al. (2014), Pozo et al. (2013, 2017) and Moreira et al. (2018); and (ii) a game theoretical approach (representing the Principal-Agent type of mechanism that is embedded in the incentive incompatibility of market agents) in order to study the way of allocating the costs of the system expansions among network users through transmission tariffs or other mechanisms. We leave these topics for future work.

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Appendix A. Mathematical formulation

A.1. Notation

This section details the variables, parameters and sets used in the formulation of the optimization model, implemented in FICO Xpress.

A.1.1. Sets

$Gres$	set of hydro reservoir generators
Lcl_c	set of candidate lines to connect cluster c to the main transmission system
$Lssb_n$	set of candidate lines to connect sub-subbasin b to the main transmission system
Ncl	set of clusters
Ne	set of seasons
Ng	set of generators
Nl	set of transmission lines
Nn	set of nodes
Ns	set of hydro scenarios
$Nssb$	set of sub-subbasins
Nt	set of snapshots or operating conditions

A.1.2. Variables

$f_{l,t,e,s}$	transfer in line l at snapshot t in season e in hydro scenario s [MW]
$\theta_{l,t,e,s}^{TO}$	voltage angles at the ends of line l at snapshot t in season e in hydro scenario s [rad]
$\theta_{l,t,e,s}^{FROM}$	capacity of line l [MW]
I_l	capacity of line l [MW]
$LL_{n,t,e,s}$	lost load in node n at snapshot t in season e in hydro scenario s [MW]
$P_{g,t,e,s}$	production of generator g at snapshot t in season e in hydro scenario s [MW]
X_l	binary decision variable, where:

- $X_l = 1$ if line l is built
- $X_l =$ 0 otherwise

A.1.3. Parameters

$CF_{g,t,e,s}$	availability of generator g at snapshot t in season e in hydro scenario s [p.u.]
CV_g	variable production cost of generator g [US$/MWh]
$D_{n,t,e}$	electricity demand in node n snapshot t in season e [MW]
$Dir_{n,l}$	transfer direction in line l with respect to node n:

- $Dir_{n,l} = 1$ if transfer in line l is towards node n
- $Dir_{n,l} = -1$ if transfer in line l is from node n

F_l^{ini}	initial capacity of line l [MW]
Fix_l	fixed investment cost of line l [US$/yr]
$\bar{M}$	a large number (to apply Big-M method)
P_g^{max}	maximum capacity of generator g [MW]
$Type_l$	type of line l, where:

- $Type_l = 0$ for existing lines
- $Type_l = 1$ for candidate radial lines (from a sub-subbasin to a node of the main system)
- $Type_l = 2$ for candidate lines within a cluster of sub-subbasins (from a sub-subbasin to a another sub-subbasin belonging to the same cluster)
- $Type_l = 3$ for candidate lines connecting 2 different clusters of sub-subbasins (from a sub-subbasin to another sub-subbasin belonging to two different clusters)

Via_l	variable investment cost of line l [US$/MW.yr]

$VoLL$	value of lost load [US$/MWh]
z_l	reactance of line l [p.u.]
ΔT_e	duration of season e [hrs]
$\Delta T_{t,e}$	duration of snapshot t in season e [hrs]
ρ_s^{Hydro}	probability of hydro scenario s [p.u.]

A.2. Formulation

This section details the formulation of the 2-stage stochastic MILP model, implemented in FICO Xpress. Next, $x|z$ refers to x given z and x/y refers to x *minus* y, where x and y are sets and z is a condition.

A.2.1. Common formulation

This section shows the formulation that is common for all transmission expansion topologies.A.2.1.1. Objective function. The objective function seeks to minimize the overall cost of expanding the power system, including its investment and operation in both generation and transmission network.

Minimize

$$\left\{\begin{array}{c}\sum_{l\in Nl}(Fix_l\cdot X_l + Via_l\cdot I_l)+\\ \sum_{s\in Ns}\rho_s^{Hydro}\cdot\left(\sum_{e\in Ne}\left(\sum_{t\in Nt}\left(\sum_{g\in Ng}P_{g,t,e,s}\cdot CV_g\cdot\Delta T_{t,e}+\sum_{n\in Nn}LL_{n,t,e,s}\cdot VoLL\cdot\Delta T_{t,e}\right)\right)\right)\end{array}\right\}$$

A.2.1.2. Energy balance. In every node of the power network, energy demand needs to be supplied by either internal generation or imports. Alternatively, demand can be (partially) curtailed if local production plus imports do not suffice.

$$D_{n,t,e} = LL_{n,t,e,s} + \sum_{g\in Ng\wedge g\in G_n} P_{g,t,e,s} + \sum_{l\in Nl} Dir_{n,l}\cdot f_{l,t,e,s}\ \forall\ n\in Nn,\ t\in Nt,\ e\in Ne,\ s\in Ns$$

A.2.1.3. Production constraints. The energy produced by every generator is limited by its capacity or the availability of the primary resource (i.e. a solar power generator cannot produce at night). In the case of hydro reservoir, there is also a constraint that limits the summation of generation within a given period of time, due to limitations in the availability of stored water.

$$P_{g,t,e,s} \le P_g^{max}\cdot CF_{g,t,e,s}\ \ \forall\ g\in Ng/\{g\in Gres\},\ t\in Nt,\ e\in Ne,\ s\in Ns$$

$$\sum_{t\in Nt} P_{g,t,e,s}\cdot\Delta T_{t,e} \le P_g^{m\acute{a}x}\cdot CF_{g,t,e,s}\cdot\Delta T_e\ \ \forall\ g\in Gres,\ e\in Ne,\ s\in Ns$$

A.2.1.4. Power transfer constraints. Transfers among network nodes respect voltage Kirchhoff´s law and are limited by the capacity of the transmission system, which can be enhanced if investment is undertaken.

$$-F_l^{ini} - I_l \quad\le\quad f_{l,t,e,s} \le\quad F_l^{ini} + I_l \quad\forall\quad l\in Nl,\quad t\in Nt,\quad e\in Ne,\quad s\in Ns$$

$$-\bar{M}\cdot(1-X_l) + \frac{\theta_{l,t,e,s}^{FROM} - \theta_{l,t,e,s}^{TO}}{z_l} \le f_{l,t,e,s} \le \frac{\theta_{l,t,e,s}^{FROM} - \theta_{l,t,e,s}^{TO}}{z_l} + \bar{M}\cdot(1-X_l)\quad\forall\ l\in Nl,\quad t\in Nt,\quad e\in Ne,\quad s\in Ns$$

A.2.2. Formulation per strategy

Unlike the previous section, this section shows the model that is used for the expansion of the transmission corresponding to each topology. All types of transmission lines modeled in this section correspond to the so-called additional[3] transmission system.A.2.2.1. Equations to model the radial, fully decentralized strategy. In this coordination level, each new generation project owner builds a direct, “radial” line to the main electricity system without coordinating with further parties (so the line capacity is fitted for the necessities of a single project only) and without considering, as a landing/access point, existing substations that are privately owned by other generators. This strategy represents the minimum coordination level.

In order to reduce the number of candidate topological combinations of new lines, new generators can be connected to the main system by either the line with the shortest path or the second shortest path and this is a decision of the mathematical program (so, every sub-subbasin presents 2 candidate lines for main grid connection). Note that the line with the shortest path may not be the less costly one since there are further costs that the program attempts to optimize as that associated with the main transmission network. This is modeled through the following equations.

$$X_l\in\{0,1\}\ \ \forall\ \ l\in Nl\mid Type_l = 1$$

$$I_l \le\ \bar{M}\cdot X_l\ \ \forall\ \ l\in Nl\mid Type_l = 1$$

$$\sum_{l\in Lssb_b} X_l = 1\ \ \forall\ \ b\in Nssb$$

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[3] The transmission network is divided into 3 categories or regimes in the Chilean system: national or trunk (dedicated to transfer power at the national level), zonal or subtransmission (dedicated to transfer power at a more local level, i.e., from the trunk system to distribution system), and dedicated or additional network (dedicated to connect either generators or private, large consumers to the rest of the system). Generally speaking, the owners of national and zonal systems are network companies, while the owners of dedicated systems are generation companies.

A.2.2.2. Equations to model the pseudo coordinated strategy. In the pseudo coordinated strategy, a group of new generators located nearby can coordinate to build a shared transmission infrastructure (composed of lines and a "collector" substation) and therefore connects to the main system through a single transmission line. As points of landing/access, all substations nearby are considered, even those owned by other, existing generators. Hence, there are two kinds of decisions regarding new transmission lines:

(a) Topology of a new network among the members of the group or cluster of generators
(b) Landing point in the main system to connect the group of generators to the electricity system

Regarding (a), this is obtained separately and prior to run the optimization model. To do so, we determine a *minimum spanning tree* to interconnect all members of the group/cluster of new generators. Regarding (b), we optimize the connection of the new line between the main system and the group/cluster of new generators. Each member of the cluster can be connected to the nearest or second nearest system substation (and this defines the set of candidate connections), but we limit the model to select only one connection between system and cluster as shown in the equations below (last set of equations for type 2 lines $I_l \leq \bar{M}\cdot X_l$ is written here for completeness, although it is evidently not needed):

$$X_l \in \{0,\ 1\}\ \ \forall\ \ l \in Nl \mid Type_l = 1$$

$$I_l \leq\ \bar{M}\cdot X_l \quad \forall\ \ l \in Nl \mid Type_l = 1$$

$$\sum_{l \in Lcl_c} X_l = 1\ \ \forall\ \ c \in Ncl$$

$$X_l = 1 \quad \forall\ \ l \in Nl \mid Type_l = 2$$

$$I_l \leq\ \bar{M}\cdot X_l \quad \forall\ \ l \in Nl \mid Type_l = 2$$

A.2.2.3. Equations to model the fully coordinated strategy. Under this strategy, all new generators (i.e., sub-subbasin) can be fully coordinated to interconnect among themselves and consider all available options as a landing substation in the main grid, even those owned by other, existing generators. This strategy represents the maximum coordination level.

In order to reduce the number of candidate topological combinations of new lines, we consider the same clusters or groups of new generators (i.e., sub-subbasins) defined in the previous section, but rather than connecting each cluster to the main system directly, we allow the model to connect the clusters among themselves and then decide the connection of these clusters to the main system. In other words, we follow the following approach:

- group several new generators (or sub-subbasin) in various clusters, then
- interconnect these clusters among themselves,
- finally connect a few of these clusters to the main system.

To further limit the amount of candidate lines that connect a cluster to the main system we use, as previously, the shortest and second shortest transmission path from a cluster to the main system. The equations used to model this are as follows (third last set of equations for type 2 lines $I_l \leq \bar{M}\cdot X_l$ is written here for completeness, although it is evidently not needed):

$$X_l \in \{0,\ 1\}\ \ \forall\ \ l \in Nl \mid Type_l = 1$$

$$I_l \leq\ \bar{M}\cdot X_l \quad \forall\ \ l \in Nl \mid Type_l = 1$$

$$\sum_{l \in Lcl_c} X_l \leq 1 \quad \forall\ \ c \in Ncl$$

$$X_l = 1\ \ \forall\ l \in Nl \mid Type_l = 2$$

$$I_l \leq\ \bar{M}\cdot X_l \quad \forall\ \ l \in Nl \mid Type_l = 2$$

$$X_l \in \{0,\ 1\}\ \ \forall\ \ l \in Nl \mid Type_l = 3$$

$$I_l \leq\ \bar{M}\cdot X_l\ \forall\ \ l \in Nl \mid Type_l = 3$$

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