Economic Criteria for Planning Transmission Investment in Restructured Electricity Markets

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***Abstract*—From an economic perspective, a common criterion for assessing the merits of a transmission investment is its impacts on social welfare. The underlying assumption in using this criterion is that side payments may be used to distribute the social gains among all market players. In reality, however, since the impacts of an electricity transmission project on different players may vary, such side payments are rather difficult to implement.**

This paper focuses on different economic criteria that should be considered when planning electricity transmission investments. We propose an electricity transmission investment assessment methodology that is capable of evaluating the economic impacts on the various effected stakeholders and account for strategic responses that could enhance or impede the investment's objectives. We formulate transmission planning as an optimization problem under alternative conflicting objectives and investigate the policy implications of divergent expansion plans resulting from the planner's level of anticipation of strategic responses. We find that optimal transmission expansion plans may be very sensitive to supply and demand parameters. We also show that the transmission investments have significant distributional impact, creating acute conflicts of interests among market participants. We use a 32-bus representation of the main Chilean grid to illustrate our results.

***Index Terms*—Market power, network expansion planning, power system economics, power transmission planning.**

I. Introduction

THE primary drivers for transmission upgrades and expansions are reliability considerations and interconnection of new generation facilities. However, because the operating and investment decisions by generation firms are market driven, it is needed to take into consideration some economic criteria when planning transmission investments. From an economic perspective, a common criterion for assessing the merits of a transmission investment is its impacts on social welfare.[1] The underlying assumption in using this criterion is that side payments and charges may be used to distribute the social gains among all market players. In reality, however, this is not always the case in deregulated electric systems, where transfers are not always feasible and even when attempted are subject to many imperfections. In some parts of the U.S. power system, which was originally designed to serve a vertically integrated market, there are misalignments between payments and rewards associated with use and investments in transmission. In fact, while payments for transmission investments and for its use are made locally (at state level), the economic impacts from these transmission investments extend beyond state boundaries so that the planning and approval process for such investment falls under Federal Energy Regulatory Commission (FERC) jurisdiction. As a result of such jurisdictional conflict adequate side payments among market participants are not always physically or politically feasible. (For instance, this would be the case of a network expansion that benefit a particular generator or load in another state, so that the cost of the expansion is not paid for by those who truly benefit from it.) Consequently, the maximization of social welfare may not translate to Pareto efficiency and other optimizing objectives should be considered. Unfortunately, alternative objectives may produce conflicting results with regard to the desirability of transmission investments.

One potential solution to the aforementioned jurisdictional conflict is the so-called "participant funding", which was proposed by FERC in its 2002 Notice of Proposed Rulemaking (NOPR) on Standard Market Design [1]. Roughly, participant funding is a mechanism whereby one or more parties seeking the expansion of a transmission network (who will economically benefit from its use) assume funding responsibility. This scheme would assign the cost of a network expansion to the beneficiaries from the expansion thus, eliminating (or, at least, mitigating) the side-payments' problem mentioned above.

Although participant funding would potentially encourage greater regional cooperation to get needed facilities sited and built, this approach has some caveats in practice. Two of the main shortcomings of participant funding are that i) the benefits from network upgrades are difficult to quantify and to allocate among market participants since any network upgrade will likely affect prices everywhere in the network and ii) mitigation of network bottlenecks is likely to require a program of system-wide upgrades, from which many market participants are likely to benefit, but for which the cumulative benefits can be difficult to capture through participant funding.

Within this context, a transmission investment assessment methodology should be capable of evaluating the economic impacts on the various effected stakeholders and account for strategic responses that could enhance or impede the investment's objectives. In this paper, we propose such an

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[1]While there is a long-standing debate in economics about the correct social welfare metric, we will use the common definition of social welfare as the sum of producers' and consumers' surplus net of investment cost, although in our comparisons among different investment options we will ignore investment cost differences.

assessment methodology based on a model that formulates transmission planning as an optimization problem under alternative conflicting objectives and allows the study of the policy implications of divergent expansion plans resulting from the planner's level of anticipation of strategic responses.

Most of the literature about transmission planning in deregulated electric systems considers the maximization of social welfare as the sole optimization objective while literature that deals with alternative conflicting planning objectives is scarce. London Economics International, LLC, developed a methodology to evaluate specific transmission proposals using an objective function for transmission appraisal that allows the user to vary the weights applied to producer and consumer surpluses [2]. However, London Economics' study has no view on what might constitute appropriate weights nor on how changes in the weights affect the proposed methodology. In [3], the authors discuss the issue of conflicting interests and their reconciliation to achieve a social optimum under different network management structures. However, the decision model they use contains some strong simplifying assumptions such as cost-based bidding by generation firms.

The rest of the paper is organized as follows. Section II shows that different desired optimizing objectives can result in divergent optimal expansions of a transmission network and that this fact entails some very important policy implications, which should be considered by any decision maker concerned with transmission expansion. In Section III, we suggest a multistage game-theoretic framework for electricity transmission investment as a new planning paradigm that incorporates the effects of strategic interaction between generation and transmission investments and the impact of transmission on spot energy prices. This model takes into account the policy implications of the conflicting incentives for transmission investment and explicitly considers the interrelationship between generation and transmission investments in oligopolistic power systems. In Section IV, we illustrate our results using a reduced representation of the main Chilean grid [the "Sistema Interconectado Central" (SIC)]. Section V concludes the paper.

II. Alternative Conflicting Optimization Objectives for Transmission Expansions

A. Radial-Network Example

For any given network, the network planner would ideally like to find and implement the transmission expansion that maximizes social welfare, minimizes the local market power of the agents participating in the system, maximizes consumer surplus and maximizes producer surplus. Unfortunately, these objectives may produce conflicting results with regard to the desirability of various transmission expansion plans. In this section, we illustrate, through a simple example, the divergent optimal transmission expansions based on different objective functions, and the difficulty of finding a unique network expansion policy.

We shall use a simple two-node network example, which is sufficient to highlight the potential incompatibilities among the planning objectives and their policy implications. This example is chosen for simplicity reasons and does not necessarily represent the behavior of a real system.

As a general framework of the example presented here, we assume that the transmission system uses nodal pricing, transmission losses are negligible, consumer surplus is the correct measure of consumer welfare, generators cannot purchase transmission rights (and, thus, their bidding strategy is independent of the congestion rent), the Lerner index (defined as the fractional price markup, i.e., [price—marginal cost]/price) is the proper measure of local market power, and transmission investment costs are negligible.

Consider a network composed of two unconnected nodes where electricity demand is served by local generators. Assume node 1 is served by a monopoly producer while node 2 is served by a competitive fringe. For simplicity, suppose that the generation capacity at each node is unlimited. We also assume both that the marginal cost of generation at node 1 is constant (this is not a critical assumption, but it simplifies the calculations) and equal to $\mathrm{c_1} = \$25/\mathrm{MWh}$, and that the marginal cost of generation at node 2 is linear in the quantity produced and given by $\mathrm{MC_2(q_2)} = 20 + 0.15 \cdot \mathrm{q_2}$. Moreover, we assume linear demand functions. In particular, the inverse demand function at node 1 is $\mathrm{P_1(q_1)} = 50 - 0.1 \cdot \mathrm{q_1}$ while the inverse demand function at node 2 is $\mathrm{P_2(q_2)} = 100 - \mathrm{q_2}$.

We analyze the optimal expansion of the described network under each of the following optimizing objectives: i) maximization of social welfare, ii) minimization of local market power, iii) maximization of consumer surplus, and iv) maximization of producer surplus. It can be shown that, for the particular two node network analyzed in this section, the optimal expansion under each of the four considered optimizing objectives is either doing nothing (that is, keeping each node as self-sufficient) or building a transmission line with "adequate" capacity (that is, building a line with high-enough capacity so that the probability of congestion is very small).[2] In the general case, we can justify this simplification based on the lumpiness of transmission investments.

As mentioned before, under the scenario in which each node satisfies its demand for electricity with local generators [self-sufficient-node scenario (SSNS)], the generation firm located at node 1 behaves as a monopolist (that is, it chooses a quantity such that its marginal cost of supply equals its marginal revenue) while the generation firms located at node 2 behave as competitive firms (that is, they take the electricity price as given by the market-clearing rule: demand equals marginal cost of supply).

Under the scenario in which there is adequate (ideally unlimited) transmission capacity between the two nodes [nonbinding-transmission-capacity scenario, (NBTCS)], the firms face an aggregate demand given by

$$\mathrm{P(Q)} = \begin{cases} 100 - \mathrm{Q}, & \text{if } \mathrm{Q} < 50 \\ 54.5 - 0.09 \cdot \mathrm{Q}, & \text{if } \mathrm{Q} \geq 50 \end{cases} \quad (1)$$

where Q is the total quantity of electricity produced by generators. That is, $\mathrm{Q} = \mathrm{q_1} + \mathrm{q_2}$, where $\mathrm{q_1}$ is the amount of electricity

[2]Recall that we are not taking into consideration any transmission investment cost in our analysis. However, the reader should be aware that the optimal expansion of the described network under the considered four planning objectives could be different from either doing nothing or building a transmission line with adequate capacity when considering the costs of transmission investments.

TABLE I
EQUILIBRIA UNDER BOTH THE SSNS AND THE NBTCS IN THE TWO-NODE NETWORK[a]

Equilibria under the SSNS	Equilibria under the NBTCS
$q_1^{(SSNS)}$= 125 MWh	$q_1^{(NBTCS)}$= 112 MWh
$q_2^{(SSNS)}$= 69.6 MWh	$q_2^{(NBTCS)}$= 101.2 MWh
$P_1^{(SSNS)}$= $37.5/MWh	$P_1^{(NBTCS)}$= $35.2/MWh
$P_2^{(SSNS)}$= $30.4/MWh	$P_2^{(NBTCS)}$= $35.2/MWh
$PS_1^{(SSNS)}$= $1,563/h	$PS_1^{(NBTCS)}$= $1,139/h
$PS_2^{(SSNS)}$= $363/h	$PS_2^{(NBTCS)}$= $768/h
$PS^{(SSNS)}$= $1,926/h	$PS^{(NBTCS)}$= $1,907/h [b]
$CS_1^{(SSNS)}$= $781/h	$CS_1^{(NBTCS)}$= $1,099/h
$CS_2^{(SSNS)}$= $2,420/h	$CS_2^{(NBTCS)}$= $2,101/h
$CS^{(SSNS)}$= $3,201/h	$CS^{(NBTCS)}$= $3,200/h
$W^{(SSNS)}$= $5,127/h	$W^{(NBTCS)}$= $5,107/h – investment costs
$L_1^{(SSNS)}$= 0.33	$L_1^{(NBTCS)}$= 0.29

[a] $\mathrm{PS}_i^{(S)}$ corresponds to the producer surplus at node i under the scenario S; $\mathrm{PS}^{(S)}$ corresponds to the total producer surplus under the scenario S; $\mathrm{CS}_i^{(S)}$ corresponds to the consumer surplus at node i under the scenario S; $\mathrm{CS}^{(S)}$ corresponds to the total consumer surplus under the scenario S; $\mathrm{W}^{(S)}$ corresponds to the total social welfare under the scenario S; and $\mathrm{L}_1^{(S)}$ corresponds to the Lerner index at node 1 under the scenario S.
[b] Not accounting for transmission investment costs.

produced by the firm located at node 1 and q_2 is the aggregate amount of electricity produced by the firms located at node 2.

Under the NBTCS, the two nodes may be treated as a single market where the generator at node 1 and the competitive fringe at node 2 jointly serve the aggregate demand of both nodes at a single market clearing price. We assume that the node 1's firm behaves as a Cournot oligopolist interacting with the competitive fringe (that is, under the NBTCS, we assume both that the firm at node 1 chooses a quantity such that its marginal cost of supply equals its marginal revenue, taking the output levels of the other generation firms as fixed, and that the generation firms at node 2 still take the electricity price as given by the market-clearing rule).

The resulting equilibria under both the SSNS and the NBTCS are summarized in Table I. In computing the social welfare obtained under the NBTCS, we assume that an independent entity (other than the existing generation firms and consumers) incurs in the transmission investment costs.

Comparing both the SSNS and the NBTCS, we observe that the expansion that minimizes the local market power of generation firms is building a transmission line with "adequate" capacity (at least theoretically, with capacity greater than 36 MWh) since $\mathrm{L}^{(\mathrm{NBTCS})} < \mathrm{L}^{(\mathrm{SSNS})}$. However, the expansion that maximizes social welfare would keep each node as self-sufficient ($\mathrm{W}^{(\mathrm{NBTCS})} < \mathrm{W}^{(\mathrm{SSNS})}$, even if the investment costs were negligible). Moreover, both the expansion that maximizes total consumer surplus and the expansion that maximizes total producer surplus are keeping each node as self-sufficient (i.e., $\mathrm{CS}^{(\mathrm{NBTCS})} < \mathrm{CS}^{(\mathrm{SSNS})}$ and $\mathrm{PS}^{(\mathrm{NBTCS})} < \mathrm{PS}^{(\mathrm{SSNS})}$). This means that, in this particular case, while the construction of a nonbinding-capacity transmission line linking both nodes minimizes the local market power of generation firms, this network expansion decreases social welfare, total consumer surplus, and total producer surplus. Figs. 1–3 illustrate these findings.

Fig. 1 shows that, in this particular case, the construction of the nonbinding-capacity transmission line reduces social welfare even if the investment costs were negligible. Furthermore,

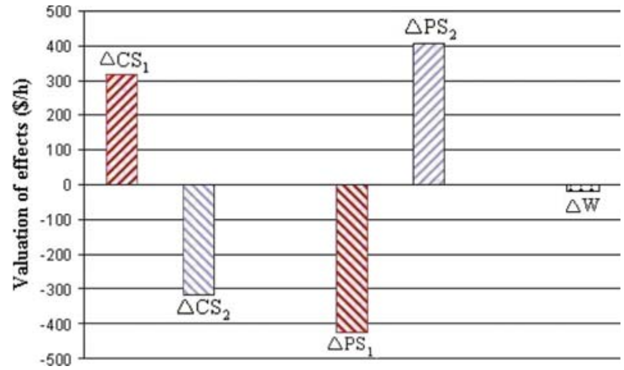

Fig. 1. Effects on consumers and producers of building a nonbinding-transmission-capacity line between both nodes, assuming that the investment costs are negligible.

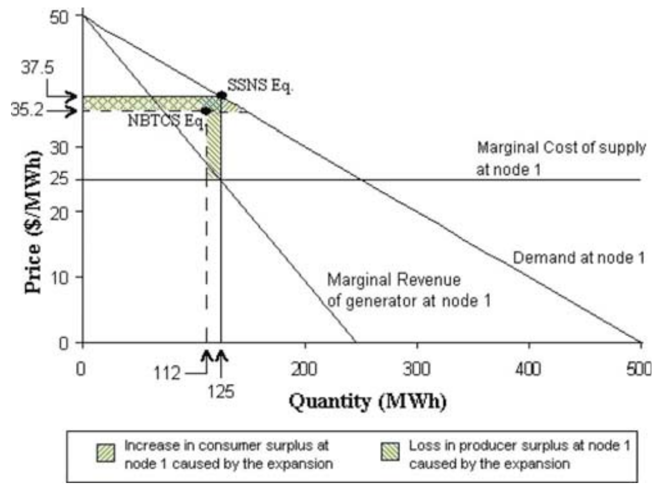

Fig. 2. Equilibrium at node 1 under both the SSNS and the NBTCS.

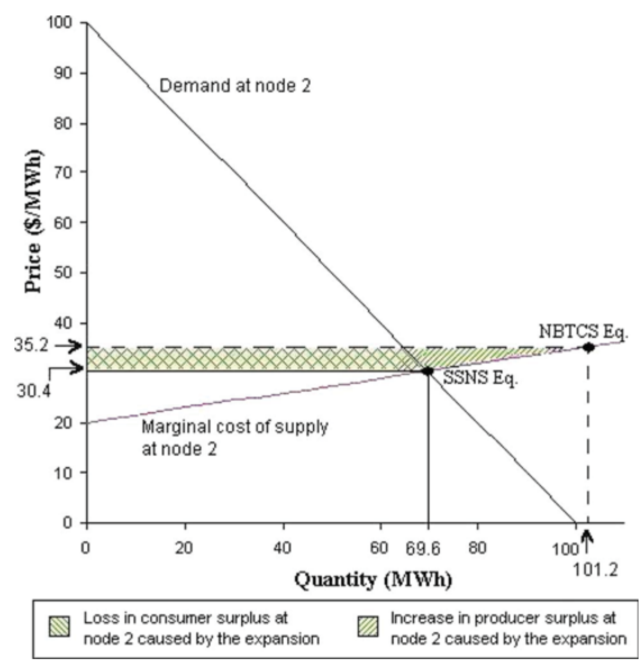

Fig. 3. Equilibrium at node 2 under both the SSNS and the NBTCS.

this figure leads to an interesting observation: if the consumers at node 1 (and/or the producers at node 2) had enough political power, then they could encourage the construction of a nonbinding-capacity transmission line linking both nodes even though it would decrease social welfare. That is, in this case, the "winners" from the transmission investment (consumers at node 1 and generation firms at node 2) can be expected to expend up to the amount of rents that they stand to win to obtain approval of this expansion project although it reduces social welfare.

It is also interesting to note that, in this example, building the transmission line between the two nodes will result in flow from the expensive-generation node to the cheap-generation node, so that the transmission line cannot realize the potential gains from trade between the two nodes. On the contrary, such a flow decreases social welfare. This phenomenon is due to the exercise of market power by the firm at node 1, which finds it advantageous to let the competitive fringe increase its production by exporting power to the cheap node, in order to sustain a higher market price.

In economic trade theory, *gains from trade* is defined as the improvement in consumer incomes and producer revenues that arise from the increased exchange of goods or services among the trading areas. It is well understood that, in absence of market power (i.e., excluding all monopoly rents), the trade between areas must increase the total benefit of all the areas combined [4]. That is, gains from trade must be a nonnegative quantity. This rationale underlines common wisdom that prevailed in a regulated environment justifying the construction of transmission between cheap and expensive generation nodes on the grounds of reducing energy costs to consumers. However, as our example demonstrates, such rationale may no longer hold in a market-based environment where market power is present. This, seemingly, counterintuitive result can be explained in terms of the economic theory of the "second best,"[3] suggesting that when more than one market imperfection is present (monopoly power and lack of connectivity between the two nodes in our case) correcting one imperfection may not necessarily improve social welfare. In a simulation study, Hobbs [5] has demonstrated both that, while the phenomenon illustrated in our example is possible, it is unlikely in a probabilistic sense when demand function at the two nodes are drawn at random and that, in most cases, market power in fact magnifies the efficiency gains that could be obtained under perfect competition. Nevertheless, our example is still useful for illustrating the distributional consequences resulting from transmission expansions, which can create potential conflicts of interests among market participants.

Figs. 2 and 3 assist us to explain the results obtained in our particular example. These two figures show the price-quantity equilibria at each node under the two considered scenarios. In these figures, the solid lines represent the equilibria under the SSNS while the dotted lines correspond to the equilibria under the NBTCS.

One way of explaining the results obtained here is through the distinction between two different effects due to the construction of the nonbinding-capacity transmission line, as suggested in [6]. On one hand, competition among generation firms increases. The construction of the nonbinding-transmission-capacity line allows market participants to sell/buy power demanded/produced far away, which encourages competition among firms. This effect "forces" the firm located at node 1 to decrease its retail price with respect to the SSNS' level. As shown in Fig. 2, this price reduction causes an increase in the node 1's consumer surplus (because the demand at node 1 increases) and a reduction in the profit of the firm at node 1 with respect to the SSNS.

On the other hand, the transmission expansion also causes a substitution (in production) of some low-cost power by more expensive power as result of the exercise of local market power. That is, the firm at node 1 can reduce its output (although the demand at node 1 increases with respect to the SSNS) and keep the retail price higher than the SSNS market-clearing price at node 2 in order to maximize its profit under the NBTCS. As this happens, the node 2's firms increase their output levels (increasing both the generation marginal cost and the retail price at node 2 with respect to the SSNS equilibrium) up to the NBTCS equilibrium point where the retail prices at both nodes are equal (assuming the transmission constraint is not binding) and the total demand is met. As shown in Fig. 3, at this new equilibrium, the producer surplus at node 2 increases while the consumer surplus at node 2 decreases with respect to the SSNS. In other words, the exercise of local market power by the node 1's firm causes a substitution of some of the low-cost power generated at node 1 by more expensive power produced at node 2 to meet demand. This out-of-merit generation, caused by the transmission expansion, reduces social welfare with respect to the SSNS.

Summarizing, while the first effect (competition effect) is social-welfare improving, the second effect (substitution effect) is social-welfare decreasing in the case of the example presented in this section. Furthermore, the substitution effect dominates in this particular example. Two facts contribute to the explanation of the dominance of the substitution effect in this case: i) the generation marginal cost at node 1 is much lower than the one at node 2 (for the relevant output levels), although the pre-expansion price at node 1 is higher than the equilibrium price at node 2 and ii) the demand and supply curves at node 2 are much more inelastic than those at node 1.

The analysis shown in this section makes evident that the transmission expansion plan that minimizes the local market power of generation firms may differ from the expansion plan that maximizes social welfare, consumer surplus, or total producer surplus when the effect of the expansion on market prices is taken into consideration. Likewise, the transmission expansion plan that maximizes total producer surplus may differ from the expansion plan that maximizes social welfare and consumer surplus, while the transmission expansion plan that maximizes total consumer surplus may differ from the expansion plan that maximizes social welfare. These conclusions can all be drawn based on the two-node network example given above by simply considering $c_1 = \$26/\mathrm{MWh}$ and $c_1 = \$24/\mathrm{MWh}$, respectively.

Finally, it is worth to mentioning that our Cournot assumption is not essential in order to derive the qualitative results and conclusions presented here. The different optimization objectives we have considered may result in divergent optimal trans-

[3]This observation is due to Hobbs [5].

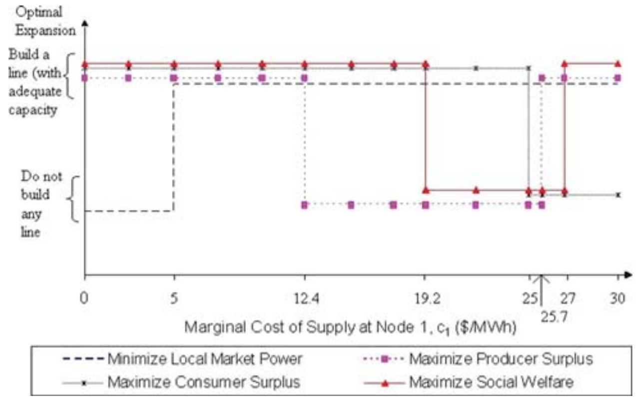

Fig. 4. Sensitivity to the marginal cost of supply at node 1 in the two-node network.

mission expansion plans even when we model the competitive interaction of the generation firms as Bertrand competition.

B. Sensitivity Analysis in the Radial-Network Example

It is interesting to study the behavior of our two-node network under perturbation of some supply and/or demand parameters. Next, we present a sensitivity analysis of the optimal network expansion decision with respect to the marginal cost of supply at node 1, c_1.

Fig. 4 shows the changes in the optimal network expansion plan, under each of the four optimization objectives we have considered, as we vary the marginal cost of generation at node 1 (keeping all other parameters unaltered and assuming that investment costs are negligible).

We note that none of the optimizing objectives leads to a consistent optimal expansion for all values of the parameter c_1. Moreover, Fig. 4 demonstrates that only for values of c_1 between $5/MWh and $12.4/MWh the four optimization objectives lead to the same optimal expansion plan. For c_1 higher than $5/MWh, the competition among generation firms intensifies under the NBTCS, forcing the node 1's firm to reduce its price (i.e., $P_1^{(NBTCS)} < P_1^{(SSNS)}$), thus decreasing the firm's market power. Moreover, for c_1 lower than $12.4/MWh, under the SSNS, the node 1's firm sets a price lower than the equilibrium price at node 2 (i.e., $P_1^{(SSNS)} < P_2^{(SSNS)}$). Thus, in this case, there is a net transmission flow from node 1 to node 2 under the NBTCS, which improves producer surplus, consumer surplus, and social welfare with respect to the SSNS.

From Fig. 4, we can also observe that the optimal network expansion plan under most of the optimization objectives is highly sensitive to c_1 (especially when this parameter has values between $25/MWh and $27/MWh).

Another interesting observation from Fig. 4 is that, even if we assume that the investment costs are negligible, it may not always be the best decision to expand the transmission system to the point of zero congestion.

A sensitivity analysis of the optimal network expansion plan to some demand parameters was also performed. Modifying some of the demand function parameters, while keeping all supply parameters unaltered, leads to qualitative results that are similar to those observed when we vary the supply cost at node 1. Such an analysis shows that the optimal expansion plan, under each of the four optimization objectives we have considered, is highly sensitive to the demand structure.

C. Policy Implications

Next, we present three important policy implications of the results previously discussed.

First, we showed that the optimal expansion plan of a network depends on the optimizing objective utilized and that, in a market-based environment where more than one market imperfection is present, eliminating network congestion may not necessarily improve social welfare. One consequence of this is that policy makers must be aware of the fact that expanding the transmission system to the point of zero congestion may not always be the best decision, even when transmission investment costs are not taken into consideration.

Second, we observed that the optimal network expansion plan can be highly sensitive to supply and demand parameters. Even when the optimizing objective is clearly determined, the optimal network expansion plan changes depending on the cost structure of the generation firms. Since generation costs are typically uncertain and depend on factors like the available generation capacity or the generation technology used, which in turn affect the optimal network investment plan, it follows that the interrelationship between generation and transmission investments should be considered when evaluating any transmission expansion project. Accounting for such interactions has been part of the integrated resource planning paradigm that prevailed under the regulated vertically integrated electricity industry, but is no longer feasible in the restructured industry. In Section III below, we describe a model that offers a way of accounting for generators' responses to transmission investment in an unbundled electricity industry with a competitive generation sector.

Third, our analysis shows that transmission investments have important distributional impact. While some transmission investments can greatly benefit some market participant, they may harm some other constituents. Consequently, policy makers looking after socially efficient network expansions should be aware of the distributional impact of merchant investments. Moreover, the dynamic nature of power systems entails changes over time of not only demand and supply structures, but also the mix of market participants, which adds complexity to the valuation of merchant transmission expansion projects. Even when a merchant investment appears to be beneficial under the current market structure, the investment could become socially inefficient when future generation and transmission plans and/or demand forecasts are considered.

These policy implications motivate the need for a new transmission planning paradigm that incorporates the effects of strategic interaction between generation and transmission investments and the impact of transmission investments on the various effected stakeholders. Such a new paradigm can be offered by the model described in the next section.

III. Proactive Planning of Transmission Investments

Reference [7] presents a comprehensive review of the models on transmission expansion planning appearing in the literature.

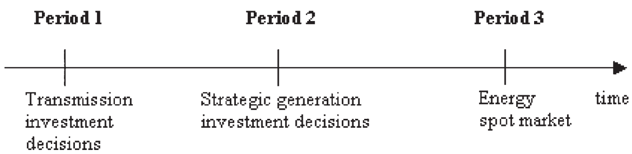

Fig. 5. Three-period transmission investment planning model.

However, none of the over 100 models considered in that literature review is compatible with the policy implications described in the previous section. In particular, none of them explicitly considers the interrelationship between the investments in generation and transmission.

In [8], we introduced the concept of a proactive transmission expansion planning as a new planning paradigm in deregulated electricity markets. In particular, taking into account the interrelationship between the generation and the transmission investments, we proposed a three-period model for studying how the exercise of local market power by generation firms affects the equilibrium between the investments in generation and transmission and, thus, the social value of the transmission capacity.

In this section, we extend the proactive transmission expansion planning model proposed in [8] in several ways[4] so that it allows us to illustrate the importance of the selection of the economic criteria for planning transmission investment in restructured electricity markets.

A. Model Assumptions

The model proposed here assumes that the transmission system uses nodal pricing, transmission losses are negligible, consumer surplus is the correct measure of consumer welfare, generators cannot purchase transmission rights (and, thus, their bidding strategy is independent of the congestion rent), and the Lerner index is the proper measure of local market power.

Moreover, we assume that all nodes are both demand nodes and generation nodes and that all generation capacity at a node is own by a single firm. Firms, however, can own generation capacity at multiple nodes. We allow generation firms to exercise local market power and assume that their interaction can be characterized through Cournot competition (i.e., firms choose their production quantities so as to maximize their profit with respect to the residual demand function while taking the production quantities of other firms and the dispatch decisions of the system operator as given). Furthermore, the model allows many lines to be simultaneously congested as well as probabilistic contingencies describing demand shocks, generation outages and transmission line outages.

The model consists of three periods, as displayed in Fig. 5. We assume that, at each period, players making decisions observe all previous-periods actions and form rational expectations regarding the outcome of the current and subsequent periods.

The last period (period 3) represents the energy spot market operation. That is, in this period, we compute the equilibrium quantities and prices of electricity over given generation and transmission capacities determined in the previous periods. We model the energy market equilibrium in the topology of the transmission network through a DC approximation of Kirchhoff's laws. Specifically, flows on lines can be calculated by using the power transfer distribution factor (PTDF) matrix, whose elements give the proportion of flow on a particular line resulting from an injection of one unit of power at a particular node and a corresponding withdrawal at an arbitrary (but fixed) slack bus. Different PTDF matrices corresponding to different transmission contingencies, with corresponding state probabilities, characterize uncertainty regarding the realized network topology in the energy market equilibrium. We assume that generation and transmission capacities as well as demand shocks are subject to random fluctuations that are realized in period 3 prior to the production and redispatch decisions by the generators and the system operator. We further assume that the probabilities of all such credible contingencies are public knowledge.

As in [8], the energy market (period 3) equilibrium is characterized as a subgame with two stages. In the first stage, Nature picks the state of the world, which determines the actual generation and transmission capacities as well as the shape of the demand and cost functions at each node. In the second stage, firms compete in a Nash-Cournot fashion by selecting their production quantities, while taking into consideration the simultaneous redispatch decisions of the system operator whose objective is to maximize social welfare while satisfying the transmission constraints.

The spot market operation model used in [8] is invariant to the generation resource ownership structure (i.e., it is irrelevant whether a firm owns one or multiple generators). On the other hand, the model used here follows the formulation proposed in [9], which accounts for resource ownership structure. As in [9], we assume that the energy spot market is characterized by a simultaneous move Cournot-Bertrand game where the generation firms choose production quantities while the system operator determines the nodal price premiums.

In the second period, each generation firm invests in new generation capacity, which lowers its marginal cost of production at any output level. We assume that generators' production decisions are not constrained by physical capacity limits. Instead we allow generators' marginal cost curves to rise smoothly so that production quantities at any node will be limited only by economic considerations and transmission constraints. In this framework, generation expansion is modeled as "stretching" the supply function so as to lower the marginal cost at any output level and thus increase the amount of economic production at any given price. Such expansion can be interpreted as an increase in generation capacity in a way that preserves the proportional heat curve or alternatively assuming that any new generation capacity installed will replace old, inefficient plants and, thereby, increase the overall efficiency of the portfolio of plants in producing a given amount of electricity. This continuous representation of the supply function and generation expansion serves as a proxy to actual supply functions that end with a vertical segment at the physical capacity limit. Since typically generators are operated so as not to hit their capacity limits (due to high heat rates and costly wear on the generators) our proxy should be expected to produce realistic results.

[4]One of the important extensions presented here is the consideration of alternative optimizing objectives for transmission planning (the expected social welfare is the sole optimizing objective considered in [8]).

In our model, we assume that, in making their investment decisions in period 2, the generation firms are aware of the transmission expansion from period 1 and form rational expectations regarding the investments made by their competitors and the resulting market equilibrium in period 3.

Finally, in period 1, the network planner evaluates different transmission expansion projects while anticipating the generators' and the system operator's response in periods 2 and 3. Because the transmission planner under this paradigm anticipates the response by the generators, optimizing the transmission investment plan will determine the best way of inducing generation investment so as to optimize the objective function set by the transmission planner. We therefore will use the term proactive network planner to describe such a Stackelberg leader.

In this paper, we limit the transmission expansion decision to expanding the capacity of any single line according to some specific transmission-planning objective. Our model allows both the upgrades of existing transmission lines and the construction of new transmission lines. Transmission upgrades that affect the electric properties of lines will obviously alter PTDF matrices. Consequently, our model explicitly takes into consideration the changes in the PTDF matrices that are induced by alterations in either the network structure or the electric characteristics of transmission lines.

We further assume that the generation cost functions are both increasing and convex in the amount of output produced and decreasing and convex in the generation capacity. Furthermore, as we mentioned before, we assume that the marginal cost of production at any output level decreases as generation capacity increases. Moreover, we assume that both the generation capacity investment cost and the transmission capacity investment cost are linear in the extra-capacity added. We also assume downward-sloping linear demand functions at each node. To further simplify things, we assume no wheeling fees.

B. Model Notation

Sets:
- N: set of all nodes;
- L: set of all transmission lines;
- C: set of all states of contingencies;
- N_G: set of generation nodes controlled by firm G;
- Y: set of all generation firms.

Decision variables:
- q_i^c: quantity generated at node i in state c;
- p^c: energy price at the reference bus in state c;
- r_i^c: import/export power quantity into/from node i by the system operator in state c;
- δ_i^c: locational price premium of node i in state c;
- g_i: expected generation capacity at node i after period 2;
- f_ℓ: expected thermal capacity limit of line ℓ after period 1.

Parameters:
- g_i^0: expected generation capacity at node i before period 2;
- f_ℓ^0: expected thermal capacity of line ℓ before period 1;
- g_i^c: generation capacity at node i in state c, given g_i;
- f_ℓ^c: thermal capacity limit of line ℓ in state c, given f_ℓ;
- $P_i^c(\cdot)$: inverse demand function at node i in state c;
- $CP_i^c(q_i^c, g_i^c)$ production cost function of the generator located at node i in state c;
- $CIG_i(g_i, g_i^0)$: cost of investment in generation capacity at node i to bring expected generation capacity to g_i;
- $CI_\ell(f_\ell, f_\ell^0)$: investment cost in line ℓ to bring expected transmission capacity to f_ℓ;
- $\phi_{\ell,\mathrm{i}}^c(L)$: power transfer distribution factor on line ℓ with respect to a unit injection/withdrawal at node i, in state c, when the network properties (network structure and electric characteristics of all lines) are given by the set L.

C. Model Formulation

First, we formulate the period-3 problem. In the first stage of the third period, Nature determines the state of the world, c. In the second stage, for a given state c, the system operator solves the following welfare maximizing redispatch problem:

$$\begin{aligned}
&\mathrm{Max}_{\{r_i^c, i\in N\}} \Delta W^c = \sum_{\mathrm{i\in N}} \int_{q_i^c}^{q_i^c+r_i^c} P_i^c(\tau)d\tau \\
&s.t. \qquad \sum_{i\in N} r_i^c = 0 \\
&\qquad -f_\ell^c \le \sum_{\mathrm{i\in N}} \phi_{\ell,\mathrm{i}}^c(L)\cdot r_i^c \le f_\ell^c, \quad \forall \ell \in L \\
&\qquad q_i^c + r_i^c \ge 0, \quad \forall i \in N. \qquad (2)
\end{aligned}$$

Our model assumptions guarantee that (2) is a concave programming problem, which implies that first order necessary conditions (i.e., KKT conditions) are also sufficient. The KKT conditions for the problem defined in (2) are

$$P_i^c(q_i^c + r_i^c) - p^c + \sum_{\ell\in L}\left(\lambda_{\ell-}^c - \lambda_{\ell+}^c\right)\cdot \phi_{\ell,i}^c(L) + \beta_i^c = 0, \quad \forall i \in N, c\in C \qquad (3)$$

$$\sum_{i\in N} r_i^c = 0, \quad \forall c \in C \qquad (4)$$

$$-f_\ell^c \le \sum_{i\in N}\phi_{\ell,i}^c(L)\cdot r_i^c \le f_\ell^c, \quad \forall \ell\in L, c\in C \qquad (5)$$

$$q_i^c + r_i^c \ge 0, \quad \forall i\in N, c\in C \qquad (6)$$

$$\lambda_{\ell-}^c \cdot \left(f_\ell^c + \sum_{i\in N}\phi_{\ell,i}^c(L)\cdot r_i^c\right) = 0, \quad \forall \ell\in L, c\in C \qquad (7)$$

$$\lambda_{\ell+}^c \cdot \left(f_\ell^c - \sum_{i\in N}\phi_{\ell,i}^c(L)\cdot r_i^c\right) = 0, \quad \forall \ell\in L, c\in C \qquad (8)$$

$$\beta_i^c\cdot(q_i^c + r_i^c) = 0, \quad \forall i\in N, c\in C \qquad (9)$$

$$\lambda_{\ell-}^c \ge 0, \quad \forall \ell\in L, c\in C \qquad (10)$$

$$\lambda_{\ell+}^c \ge 0, \quad \forall \ell\in L, c\in C \qquad (11)$$

$$\beta_i^c \ge 0, \quad \forall i\in N, c\in C \qquad (12)$$

where p^c is the Lagrange multiplier corresponding to the energy balance constraint, $\lambda_{\ell-}^c$ and $\lambda_{\ell+}^c$ are the Lagrange multipliers corresponding to the transmission capacity constraints, and β_i^c are the Lagrange multipliers corresponding to the nonnegativity constraints in (2).

Condition (3) implies that the nodal price at node i is

$$P_i^c\left(q_i^c + r_i^c\right) = p^c + \delta_i^c \tag{13}$$

where $\delta_i^c = -\sum_{\ell \in L}(\lambda_{\ell-}^c - \lambda_{\ell+}^c) \cdot \phi_{\ell,i}^c(L) - \beta_i^c$. Thus

$$\left(P_i^c\right)^{-1}\left(p^c + \delta_i^c\right) = q_i^c + r_i^c \tag{14}$$

and, due to (4), we obtain

$$\sum_{j \in N} q_j^c = \sum_{j \in N} \left(P_j^c\right)^{-1}\left(p^c + \delta_j^c\right). \tag{15}$$

Simultaneously with the system operator's decision, each firm chooses its production quantity so as to maximize profits with respect to the residual demand function. Equation (15) is an implicit representation of the residual demand function faced by each generation firm, which describes the aggregate demand quantity faced by each firm as function of the reference bus price, parametric on the rival production quantities and the nodal price markups set by the system operator. Thus, generation firm $G(G \in Y)$ solves the following profit-maximization problem (for the given state c)

$$\begin{aligned} &\mathrm{Max}_{\left\{q_i^c, i \in N_G\right\}, p^c} \pi_{\mathrm{G}}^{\mathrm{c}} = \sum_{i \in N_G} \left\{\left(p^c + \delta_i^c\right) \cdot q_i^c - CP_i^c\left(q_i^c, g_i^c\right)\right\} \\ &s.t. \qquad q_i^c \geq 0, \quad i \in N_G \\ &\qquad\qquad \sum_{j \in N} q_j^c = \sum_{j \in N} \left(P_j^c\right)^{-1}\left(p^c + \delta_j^c\right). \end{aligned} \tag{16}$$

Our model assumptions guarantee that (16), as well as (2), are concave programming problems, which implies that first order necessary conditions (i.e., KKT conditions) are also sufficient. Consequently, to solve the period-3 (energy spot market) equilibrium, we can just jointly solve the KKT conditions of the problems defined in (16) for all generation firms and (2), as well as considering (13), which together form a linear complimentarily problem (LCP).

The KKT conditions for the problems defined in (16) are

$$p^c + \delta_i^c - \frac{\partial CP_i^c\left(q_i^c, g_i^c\right)}{\partial q_i^c} + \gamma_i^c - \mu^c = 0, \quad \forall i \in N_G, G \in Y, c \in C \tag{17}$$

$$\sum_{i \in N_G} q_i^c + \mu^c \cdot \sum_{j \in N} \frac{\partial \left(P_j^c\right)^{-1}\left(p^c + \delta_j^c\right)}{\partial p^c} = 0, \quad \forall c \in C \tag{18}$$

$$\gamma_i^c \cdot q_i^c = 0, \quad \forall i \in N_G, G \in Y, c \in C \tag{19}$$

$$q_i^c \geq 0, \quad \forall i \in N_G, G \in Y, c \in C \tag{20}$$

$$\gamma_i^c \geq 0, \quad \forall i \in N_G, G \in Y, c \in C \tag{21}$$

$$\sum_{j \in N} q_j^c = \sum_{j \in N} \left(P_j^c\right)^{-1}\left(p^c + \delta_j^c\right), \quad \forall c \in C \tag{22}$$

where $\gamma_{\mathrm{i}}^{\mathrm{c}}$ and μ^{c} are the Lagrange multipliers corresponding to the nonnegativity constraints and the residual-demand constraint in (16), respectively.

In period 2, each firm determines how much to invest in new generation capacity by maximizing the expected value of the investment (we assume risk-neutral firms) subject to the anticipated actions in period 3. Hence, firm G solves the following optimization problem in period 2:

$$\begin{aligned} &\mathrm{Max}_{\{g_i, i \in N_G\}} \mathrm{E_c}\left[\pi_{\mathrm{G}}^{\mathrm{c}}\right] - \sum_{i \in N_G} CIG_i\left(g_i, g_i^0\right) \\ &s.t. \qquad (3)-(13) \text{ and } (17)-(22), \quad G \in Y. \end{aligned} \tag{23}$$

The problem in (23) is a Mathematical Program with Equilibrium Constraints (MPEC) problem and the problem of finding an equilibrium investment strategy for all the generation firms is an Equilibrium Problem with Equilibrium Constraints (EPEC), in which each firm solves an MPEC problem parametric on the other firms investment decisions and subject to the joint LCP constraints characterizing the energy market equilibrium in period 3.[5] Unfortunately, this EPEC is constrained in a nonconvex region and, therefore, we cannot simply write down the first order necessary conditions for each firm and aggregate them into a large problem to be solved directly. In Section IV, we solve for EPEC equilibria corresponding to the particular case-study network by iterative deletion of dominated strategies. That is, we sequentially solve each firm's expected-profit-maximization problem using as data the optimal values from previously solved problems. We solve each firm's expected-profit-maximization problem by employing a sequential quadratic programming algorithm.

Finally, in period 1, the network planner makes a single transmission expansion decision that will determine which line it should upgrade, and what transmission capacity it should consider for that line, in order to optimize its transmission-planning objective. Thus, the network planner solves the following optimization problem in period 1:

$$\begin{aligned} &\mathrm{Max}_{\{\ell, f_\ell\}} \Phi\left(q_i^c, p^c, r_i^c, \delta_i^c, \mathrm{g}_i, \ell, f_\ell\right) \\ &\mathrm{s.t.} \quad \text{All optimality conditions for periods 2 and 3} \end{aligned} \tag{24}$$

where Φ represents the transmission-planning objective used by the network planner.

In the case of considering the expected social welfare as the transmission-planning objective, we have

$$\begin{aligned} &\Phi\left(q_i^c, p^c, r_i^c, \delta_i^c, g_i, \ell, f_\ell\right) \\ &= \sum_{\mathrm{i \in N}} \mathrm{E_c}\left[\int_0^{q_i^c + r_i^c} P_i^c(q)dq - CP_i^c\left(q_i^c, g_i^c\right)\right] \\ &\quad - \sum_{\mathrm{i \in N}} CIG_i\left(g_i, g_i^0\right) - CI_\ell\left(f_\ell, f_\ell^0\right). \end{aligned}$$

D. Proactive Model Versus Reactive Model

It is interesting to compare the transmission investment decisions made by a proactive network planner (PNP) as defined above with the comparable decisions made by a reactive network planner (RNP), who plans transmission expansions by considering its impact on the energy spot market but without accounting for the strategic generation investment response and

[5] For formal definitions of MPEC and EPEC problems, see [10].

the planner's ability to influence such investments through the transmission expansion.

The RNP model has the same structure as the PNP model with the exception that the objective function used to evaluate alternative transmission investment projects in period 1 assumes that the generation stock upon which the energy market equilibrium is based is the current one. This case can be considered as a special case of the PNP model where the network planner assumes that generators are constrained in period 2 to select the same generation capacity that they already have. Accordingly, the RNP solves the following optimization problem in period 1:

$$\begin{aligned} &\mathrm{Max}_{\{\ell, f_\ell\}} \Phi\left(q_i^c, p^c, r_i^c, \delta_i^c, g_i, \ell, f_\ell\right) \\ &\text{s.t.} \qquad \text{All optimality conditions for periods 2 and 3} \\ &\qquad\qquad g_i = g_i^0, \quad \forall i \in N. \end{aligned} \tag{25}$$

In evaluating the outcome of the RNP investment policy we do consider, however, the generators' response to the transmission investment and its implication on the spot market equilibrium.

By comparing (24) and (25), we observe that solving (25) is equivalent to solving (24) when imposing the extra constraint that the generators must select the current generation capacity levels. Thus, the feasible set of (25) is a subset of the feasible set of (24). Therefore, since both (24) and (25) maximize the same objective function, the optimal solution of (25) must be in the feasible set of (24), which implies that the optimal solution of (24) cannot be worse than the optimal solution of (25).

We conclude, therefore, that the optimal value obtained from the PNP model is never worse than the optimal value obtained from the RNP model under any transmission-planning objective.

IV. Illustrative Example

To illustrate the results derived in the previous sections, we use a stylized representation of the main Chilean power network [i.e., the "Sistema Interconectado Central" (SIC)], which is displayed in Fig. 6.

The SIC is a system composed of both generation plants and transmission lines that operate to meet the most of the Chilean electricity demand. The SIC extends 1740 km. covering a territory of $326\,412\ \mathrm{km}^2$, equivalent to 43% of the country, where 93% of the population lives. At the end of 2004, the SIC had 7867 MW of installed power capacity, which was 40% thermal and 60% hydroelectric, while the annual gross generation of energy was around 36 259 GWh [11].

As shown in Fig. 6, the network we considered here has 32 buses and 37 transmission lines. We assume that each node has both local generation and local demand. We represent twelve generation firms in the system (which correspond to the eleven major generation firms in the SIC and a hypothetical firm that groups all other minor firms), each owning generation capacity at multiple locations. The electric characteristics (i.e., resistance, reactance, and thermal capacity rating) of the transmission lines of the network in Fig. 6 are obtained from [11].[6]

[6]Reference [11] contains detailed data of the electric characteristics of all the transmission lines within the SIC. We obtained the electric characteristics of the 37 lines of the network in Fig. 6 by aggregating the corresponding network data.

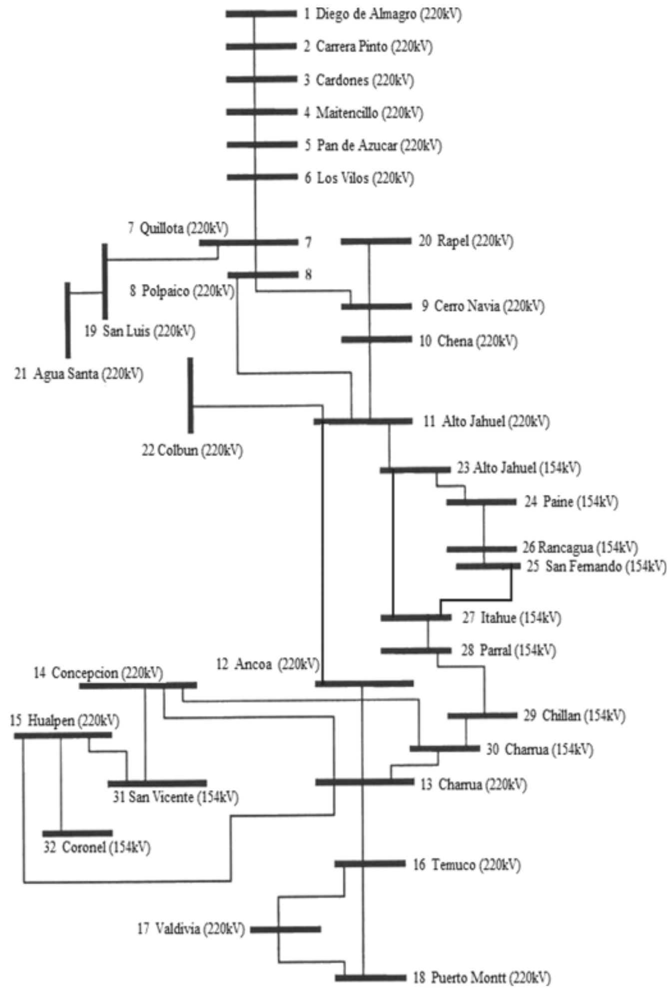

Fig. 6. Reduced representation of the Chilean SIC network.

TABLE II
States of Contingencies Associated With the Energy Market Operation

State	Probability	Type of uncertainty and description
1	0.82	Normal state: data set as in Table III
2	0.03	Demand uncertainty: all demands increase by 10%
3	0.03	Demand uncertainty: all demands decrease by 10%
4	0.03	Network uncertainty: line 8-11 goes down
5	0.03	Network uncertainty: line 13-14 goes down
6	0.03	Generation uncertainty: all facilities at node 9 goes down
7	0.03	Generation uncertainty: all facilities at node 22 goes down

The uncertainty associated with the spot market operation is classified into seven contingent states with known probabilities, as shown in Table II. Table III shows the nodal information in the normal state.

We assume that all generation firms have the same investment cost function, given by $\mathrm{CIG_i}(g_i, g_i^0) = 5\cdot(g_i - g_i^0)$, in thousands of US dollars whenever g_i and g_i^0 are expressed in MW.

TABLE III
NODAL INFORMATION OF THE SIC NETWORK IN THE NORMAL STATE

Node	Inverse demand function (\$/MWh)[a]	Generation cost function (\$/year) [b]
1	$P_1(q) = 208 - 2.4\cdot10^{-4}\cdot q$	$CP_1(q,g) = (1.5\cdot10^{-5}\cdot q^2 + 29.1\cdot q)\cdot(280/g)$
2	$P_2(q) = 111 - 2.5\cdot10^{-4}\cdot q$	$CP_2(q,g) = (5.9\cdot10^{-4}\cdot q^2 + 29.3\cdot q)\cdot(13/g)$
3	$P_3(q) = 145 - 6.6\cdot10^{-5}\cdot q$	$CP_3(q,g) = (2.9\cdot10^{-4}\cdot q^2 + 29.5\cdot q)\cdot(25/g)$
4	$P_4(q) = 148 - 2.4\cdot10^{-4}\cdot q$	$CP_4(q,g) = (6.0\cdot10^{-6}\cdot q^2 + 28.4\cdot q)\cdot(380/g)$
5	$P_5(q) = 135 - 1.0\cdot10^{-4}\cdot q$	$CP_5(q,g) = (1.4\cdot10^{-4}\cdot q^2 + 27.1\cdot q)\cdot(50/g)$
6	$P_6(q) = 129 - 2.4\cdot10^{-4}\cdot q$	$CP_6(q,g) = (3.0\cdot10^{-4}\cdot q^2 + 27.5\cdot q)\cdot(16/g)$
7	$P_7(q) = 146 - 3.4\cdot10^{-5}\cdot q$	$CP_7(q,g) = (2.3\cdot10^{-6}\cdot q^2 + 19.3\cdot q)\cdot(700/g)$
8	$P_8(q) = 167 - 6.6\cdot10^{-5}\cdot q$	$CP_8(q,g) = (1.3\cdot10^{-5}\cdot q^2 + 19.5\cdot q)\cdot(140/g)$
9	$P_9(q) = 193 - 3.9\cdot10^{-5}\cdot q$	$CP_9(q,g) = (2.7\cdot10^{-6}\cdot q^2 + 17.4\cdot q)\cdot(670/g)$
10	$P_{10}(q) = 202 - 1.0\cdot10^{-4}\cdot q$	$CP_{10}(q,g) = (6.6\cdot10^{-5}\cdot q^2 + 17.5\cdot q)\cdot(30/g)$
11	$P_{11}(q) = 212 - 5.7\cdot10^{-5}\cdot q$	$CP_{11}(q,g) = (9.4\cdot10^{-6}\cdot q^2 + 9.6\cdot q)\cdot(67/g)$
12	$P_{12}(q) = 135 - 7.4\cdot10^{-3}\cdot q$	$CP_{12}(q,g) = (1.0\cdot10^{-6}\cdot q^2 + 9.4\cdot q)\cdot(838/g)$
13	$P_{13}(q) = 155 - 9.0\cdot10^{-5}\cdot q$	$CP_{13}(q,g) = (5.6\cdot10^{-7}\cdot q^2 + 9.3\cdot q)\cdot(2275/g)$
14	$P_{14}(q) = 235 - 2.3\cdot10^{-4}\cdot q$	$CP_{14}(q,g) = (6.1\cdot10^{-5}\cdot q^2 + 9.7\cdot q)\cdot(20/g)$
15	$P_{15}(q) = 154 - 7.5\cdot10^{-4}\cdot q$	$CP_{15}(q,g) = (1.1\cdot10^{-5}\cdot q^2 + 10.3\cdot q)\cdot(75/g)$
16	$P_{16}(q) = 252 - 2.6\cdot10^{-4}\cdot q$	$CP_{16}(q,g) = (2.2\cdot10^{-5}\cdot q^2 + 10.2\cdot q)\cdot(50/g)$
17	$P_{17}(q) = 205 - 2.4\cdot10^{-4}\cdot q$	$CP_{17}(q,g) = (1.0\cdot10^{-5}\cdot q^2 + 10.4\cdot q)\cdot(110/g)$
18	$P_{18}(q) = 185 - 2.0\cdot10^{-4}\cdot q$	$CP_{18}(q,g) = (4.8\cdot10^{-6}\cdot q^2 + 10.6\cdot q)\cdot(145/g)$
19	$P_{19}(q) = 143 - 2.7\cdot10^{-4}\cdot q$	$CP_{19}(q,g) = (2.4\cdot10^{-6}\cdot q^2 + 19.1\cdot q)\cdot(870/g)$
20	$P_{20}(q) = 183 - 1.0\cdot10^{-4}\cdot q$	$CP_{20}(q,g) = (6.3\cdot10^{-6}\cdot q^2 + 10.1\cdot q)\cdot(350/g)$
21	$P_{21}(q) = 136 - 2.7\cdot10^{-4}\cdot q$	$CP_{21}(q,g) = (2.0\cdot10^{-4}\cdot q^2 + 19.2\cdot q)\cdot(75/g)$
22	$P_{22}(q) = 191 - 1.0\cdot10^{-4}\cdot q$	$CP_{22}(q,g) = (2.0\cdot10^{-6}\cdot q^2 + 10.0\cdot q)\cdot(490/g)$
23	$P_{23}(q) = 212 - 1.1\cdot10^{-4}\cdot q$	$CP_{23}(q,g) = (8.4\cdot10^{-5}\cdot q^2 + 9.6\cdot q)\cdot(17/g)$
24	$P_{24}(q) = 123 - 2.4\cdot10^{-4}\cdot q$	$CP_{24}(q,g) = (1.0\cdot10^{-3}\cdot q^2 + 18.9\cdot q)\cdot(25/g)$
25	$P_{25}(q) = 129 - 1.3\cdot10^{-4}\cdot q$	$CP_{25}(q,g) = (9.6\cdot10^{-5}\cdot q^2 + 9.6\cdot q)\cdot(10/g)$
26	$P_{26}(q) = 112 - 1.9\cdot10^{-4}\cdot q$	$CP_{26}(q,g) = (1.0\cdot10^{-5}\cdot q^2 + 10.4\cdot q)\cdot(87/g)$
27	$P_{27}(q) = 164 - 1.9\cdot10^{-4}\cdot q$	$CP_{27}(q,g) = (9.4\cdot10^{-5}\cdot q^2 + 9.4\cdot q)\cdot(25/g)$
28	$P_{28}(q) = 149 - 1.4\cdot10^{-4}\cdot q$	$CP_{28}(q,g) = (9.8\cdot10^{-5}\cdot q^2 + 9.8\cdot q)\cdot(12/g)$
29	$P_{29}(q) = 148 - 1.8\cdot10^{-4}\cdot q$	$CP_{29}(q,g) = (2.6\cdot10^{-5}\cdot q^2 + 10.5\cdot q)\cdot(40/g)$
30	$P_{30}(q) = 140 - 1.8\cdot10^{-4}\cdot q$	$CP_{30}(q,g) = (9.7\cdot10^{-5}\cdot q^2 + 9.7\cdot q)\cdot(100/g)$
31	$P_{31}(q) = 256 - 2.5\cdot10^{-4}\cdot q$	$CP_{31}(q,g) = (1.6\cdot10^{-5}\cdot q^2 + 9.8\cdot q)\cdot(125/g)$
32	$P_{32}(q) = 179 - 5.0\cdot10^{-4}\cdot q$	$CP_{32}(q,g) = (3.3\cdot10^{-5}\cdot q^2 + 10.2\cdot q)\cdot(80/g)$

[a] These inverse demand curves were obtained by using both annualized monthly data of the nodal consumption of the electricity produced in the SIC and the monthly average electricity nodal price, during 2004 (obtained from [11] and [12], respectively), and, then, performing a linear approximation to the relationship between both sets of data. The annual consumption of energy at every node, q, is measured in MWh.

[b] In the normal state, the production cost function at each generation facility was obtained by using 2004 annualized monthly data of both the production cost (due to fuel consumption in the case of the thermal units and due to the opportunity cost of the water used in producing power in the case of the hydraulic units) and the quantity of energy generated at each facility (obtained from [11]) and, then, performing a quadratic approximation to the relationship between both sets of data. The "nodal" production cost functions presented in Table III are the result of assigning each generation facility to the closest node in the network of Fig. 6 and aggregating the corresponding production cost functions. The last parenthesis of the generation cost functions given in Table III represents (g_i^0/g_i), where g_i^0 is the before-period-2 expected generation capacity assigned to node i, in MW. The annual production of energy at every node, q, is measured in MWh.

As indicated earlier, the KKT conditions for the period-3 problem of the PNP model constitute a linear complementarity problem (LCP). We solve it, for each contingent state by minimizing the complementarity conditions subject to the linear equality constraints and the nonnegativity constraints.[7] The period-2 problem of the PNP model is an EPEC, in which each firm faces a MPEC. We attempt to solve for EPEC equilibria, if at least one exists, by iterative deletion of dominated strategies. That is, we sequentially solve each firm's expected-profit-maximization problem using as data the optimal values from

[7] Greater details about the methodologies used for solving LCPs and EPEC problems are given in [9], [10] and [13].

TABLE IV
ASSESSMENT OF SINGLE TRANSMISSION EXPANSIONS UNDER THE PNP MODEL

Expansion Type	Avg. L[a]	P.S. [b] (M\$/year)	C.S. [c] (M\$/year)	C.R. [d] (M\$/year)	W [e] (M\$/year)
No expansion	**0.278**	597.2	804.3	**69.8**	1,471.3
500 MW on line 8-9	0.281	610.0	849.1	38.7	1,497.8
500 MW on line 12-13	0.285	626.1	807.8	54.5	1,488.4
500 MW on line 13-15	0.286	**630.3**	814.2	45.0	1,489.5
500 MW on new line 4-9	0.282	618.6	**872.9**	24.1	**1,515.6**
500 MW on new line 9-19	0.284	622.9	856.5	28.9	1,508.3
500 MW on new line 13-31	0.286	627.4	820.6	42.4	1,490.4

[a] Avg. L corresponds to the average expected Lerner index among all generation firms.
[b] P.S. is the expected producer surplus of the system, in millions of U.S. dollars per year.
[c] C.S. is the expected consumer surplus of the system.
[d] C.R. represents the expected congestion rents over the entire system.
[e] W is the expected social welfare of the system.

previously solved problems. Thus, starting from a feasible solution, we solve for $g_j(\forall\ j \in N_{G1})$ using $g_{(-G1)}$ as data in the first firm's optimization problem (where $g_{(-G1)}$ represents all firms' generation capacities except for firm 1's), then solve for $g_j(\forall\ j \in N_{G2})$ using $g_{(-G2)}$ as data, and so on. We solve each firm's expected-profit-maximization problem using a sequential quadratic programming algorithm implemented in MATLAB.

We do not solve the period-1 problem of the PNP model. Instead, we iteratively solve period-2 problems in which a single line has been expanded and, then, choose the transmission expansion producing the best value of the selected decision criterion. For simplicity, we do not consider transmission investment costs. In this sense, our results establish an upper bound on the amount of the line investment cost. We tested the PNP decision by comparing the results of independently adding 500 MW of transmission capacity to three existing lines and building three new lines in the network in Fig. 6. The results are summarized in Table IV.

From Table IV, we observe that if the transmission-planning decision criterion were the maximization of the expected social welfare, then the best transmission expansion alternative that a PNP could choose in this case would be a new transmission line between nodes 4 and 9. If the transmission-planning decision criterion were the maximization of the expected consumer surplus, then the best transmission expansion alternative that a PNP could choose in this case would also be a new transmission line between nodes 4 and 9. However, if the transmission-planning decision criterion were the maximization of the expected producer surplus, then the best transmission expansion alternative that a PNP could choose in this case would be the upgrade of the existing transmission line linking nodes 13 and 15. Moreover, if the transmission-planning decision criterion were the minimization of local market power, then the best transmission expansion alternative that a PNP could choose in this case would be the

TABLE V
ASSESSMENT OF SINGLE TRANSMISSION EXPANSIONS UNDER THE RNP MODEL

Expansion Type	$\overline{\text{Avg. L}}$ [a]	$\overline{\text{P.S.}}$ (M$/year)	$\overline{\text{C.S.}}$ (M$/year)	$\overline{\text{C.R.}}$ (M$/year)	$\overline{\text{W}}$ (M$/year)
No expansion	**0.245**	578.2	770.2	**42.1**	1,390.5
500 MW on line 8-9	0.246	589.4	798.8	21.6	1,409.8
500 MW on line 12-13	0.247	598.7	776.7	30.4	1,405.8
500 MW on line 13-15	0.248	600.5	780.6	26.8	1,407.9
500 MW on new line 4-9	0.246	589.0	804.5	18.2	1,411.7
500 MW on new line 9-19	0.246	592.9	**808.2**	14.8	**1,415.9**
500 MW on new line 13-31	0.248	**602.1**	783.3	23.5	1,408.9

[a] The labels in Table V have the same meaning as in Table IV.

no-expansion alternative. These results make evident the distributional impact of transmission expansions, which creates acute conflicts of interests among the various market participants.

Now, we are interested in comparing the PNP best expansion decisions with the decisions that a RNP would take under the same system conditions. We tested the RNP decisions by comparing the results of independently adding 500 MW of capacity to each one of the same six transmission lines as before. The results are summarized in Table V, where we use the notation $\overline{y}$ to represent the value of y as seen by the RNP.

In Table V, we observe that if the transmission-planning decision criterion were the maximization of the expected social welfare, then the best transmission expansion alternative that a RNP could choose in this case would be a new transmission line between nodes 9 and 19. If the transmission-planning decision criterion were the maximization of the expected consumer surplus, then the best transmission expansion alternative that a RNP could choose in this case would also be a new transmission line between nodes 9 and 19. However, if the transmission-planning decision criterion were the maximization of the expected producer surplus, then the best transmission expansion alternative that a RNP could choose in this case would be a new transmission line between nodes 13 and 31. Moreover, if the transmission-planning decision criterion were the minimization of local market power, then the best expansion alternative that a RNP could choose in this case would be the no-expansion alternative.

By comparing Tables IV and V, it is evident that the best transmission expansion decision of the PNP differs from the best decision of its reactive counterpart for most of the considered planning decision criteria. Given that we take into consideration the generators' response to the transmission expansion and its implication on the spot market equilibrium when evaluating the outcome of the RNP investment policy, it becomes evident that the RNP may select a transmission expansion option that is inferior to the one selected based on the PNP paradigm. This is because the PNP considers not only the benefit gained directly by adding transmission capacity (upon which the RNP bases its decision), but also the way in which the transmission investment induces a more efficient Nash equilibrium of expected generation capacities.

V. CONCLUSION

In this paper, we showed that transmission investments have significant distributional impact, which may create conflicts of interests among the various market participants. In particular, we illustrated through simple examples that different planning objectives may result in divergent optimal expansions of a network. Specifically, we showed that the maximization of social welfare, the minimization of local market power, the maximization of consumer surplus and the maximization of producer surplus may all result in divergent optimal transmission expansion plans. Consequently, finding a unique politically feasible and fundable network expansion policy could be a very difficult, if not impossible, task.

We also showed that the rationale of the gains from trade principle in economics may no longer hold in a market-based environment where more than one market imperfection is present (monopoly market power and lack of connectivity, in the example presented in Section II of this paper). In such a case, correcting one imperfection may not necessarily improve social welfare.

In addition, we showed that the optimal transmission expansion plan may be very sensitive to supply and demand parameters. It follows from this observation that the interrelationship between generation and transmission investments should be taken into account when evaluating any transmission expansion project. Accordingly, we proposed here a new transmission planning paradigm that offers a way of accounting for generation firms' response to transmission investment in an unbundled electricity industry with a competitive generation sector.

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