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Optimal transmission planning under the Mexican new electricity market[☆]

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ABSTRACT

This paper addresses electricity transmission planning under the new industry and institutional structure of the Mexican electricity market, which has engaged in a deep reform process after decades of a state-owned-vertically-integrated-non-competitive-closed industry. Under this new structure, characterized by a nodal pricing system and an independent system operator (ISO), we analyze welfare-optimal network expansion with two modeling strategies. In a first model, we propose the use of an incentive price-cap mechanism to promote the expansion of Mexican networks. In a second model, we study centrally-planned grid expansion in Mexico by an ISO within a power-flow model. We carry out comparisons of these models which provide us with hints to evaluate the actual transmission planning process proposed by Mexican authorities (PRODESEN). We obtain that the PRODESEN plan appears to be a convergent welfare-optimal planning process.

1. Introduction

Until 2015, Mexico's electricity system's supply side had been characterized by an industrial structure with a vertically integrated state owned monopoly, the *Comisión Federal de Electricidad* (CFE), which exclusively carried out almost all activities in electricity generation, transmission, distribution and marketing, as well as the operation of the entire electricity system.[1] The idea of the Mexican electricity reform, passed by Congress by mid-2014, is now to evolve from this closed system with asymmetrical information between CFE and the energy regulator (*Comisión Reguladora de Energía*-CRE) to a more open and transparent one, where the generation sector is liberalized so that new private generators enter the market to compete with incumbent CFE's generating plants.

The new electricity market in Mexico started operations in January 2016. For the first time in many decades, actual commercial exchange between private generators and consumers will then be possible. This in itself represents a significant change in the organization of Mexican electricity markets. Moreover, another deep transformation implied by the reform relates to electricity system operation. This function is now to be taken out from CFE's hands and left to an *independent* system operator (ISO), the *Centro Nacional de Energía* (CENACE), which will be in charge of both the short and long-run system operation as well as of electricity-grid expansion planning. The rest of the industry areas –including transmission, distribution, marketing activities and supply in the retail market– remain within CFE, but with the aim of sub-contracting private agents through competitive tenders.[2]

The expected growth in demand and increasing use of renewable energy sources in the country furthermore requires both expansion and reshaping of the current transmission network. The foreseen growth in electricity demand for 2003–2028 (85%) can be compared against the corresponding expected growth of transmission capacity (18%).[3] In its

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[1] Only some cogeneration and self-supply activities were allowed to private generators under restrictive conditions on their surplus power (that had to mainly be sold to CFE). Since 1992, independent-power-production (IPP) projects were also allowed, but only to sell under long-term contracts all of its power to CFE, who subsequently sold it to final consumers.

[2] Another crucial decision of the reform is radical transformation of the electricity pricing system, evolving from a complex regressive subsidized system (see López-Calva and Rosellón, 2002) to a more transparent pricing scheme based on nodal prices, financial transmission rights (FTRs), and direct lump-sum subsidies.

[3] CENACE (2016).

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recent 15-year plan,[4] CFE has in fact gauged 19.3 billion USD in transmission projects including 19,555 circuit-km of new lines. Compared to its main North American trade partners (USA and Canada), where electricity transmission capacity usually expands faster than demand growth,[5] it is evident that Mexico should become much more aggressive in promoting investment in transmission lines, both in terms of planning and regulatory measures.

The approach of Mexican authorities to transmission expansion is based on projected electricity demand and generation supply for an extended period (see CENACE, 2016). This projected supply and demand is ex-ante forecasted by the Mexican energy ministry (SENER). CENACE will be actually taking care of grid expansion planning based on a power-flow program that considers in an integrated simultaneous fashion generation dispatch and transmission expansion.[6] This exercise is to be repeated annually, and will provide CFE (and subcontracted private agents) a guidance on which transmission links to expand. Once a new transmission expansion project is being built, the CRE will regulate it aiming to reach a balance between risk management and incentive provision in the actual planning process of expanding networks according to PRODESEN (*Programa de Desarrollo del Sistema Eléctrico Nacional*).[7] The CRE preliminary plans to use a system of tenders (*ex-ante* competition) to select the private market agents that would cooperate with CFE to develop new transmission links.[8] These tenders would define the transmission tariffs that will be regulated through cost-plus regulation with additional periodical efficiency adjustments based on international price and performance transmission benchmarks.[9]

In this paper, we firstly propose a bi-level programming model to study the use of incentive price-cap regulation to incentivize the expansion of Mexican networks. One level (*upper level*) models the profit maximizing behavior of a transmission company (Transco) subject to price-cap regulation, and the second level (*lower level*) models the power-flow dispatch problem of the ISO.[10] Secondly, we analyze optimal centrally-planned expansion of the Mexican network through the use of a power-flow stylized model where an ISO maximizes net welfare (the sum of consumer and producer surpluses plus congestion rents minus the cost of expanding networks). Both the bi-level regulatory model and the centrally-planned expansion model are further compared to each other, also relying on simulations for other systems in North America. This exercise provides clues on the welfare-efficiency properties of the expansion plans proposed by CENACE in the design of the national transmission development plan, PRODESEN, a planning process which relies on generation-cost minimization and transmission power-flow modeling. We additionally show that incentive regulation results in a welfare-optimal expanding process, and therefore should provide the CRE with a hint on how to implement its final regulation on transmission tariffs.

Our document is organized as follows. We initially present in Section 2 a literature review on optimal transmission planning and regulation. Section 3 addresses the details of the PRODESEN plan. In Section 4 we develop our models, including data and results. First, 4.1 presents the bi-level regulatory price-cap HRV model[11] that aims to incentivize convergence of transmission tariffs to a welfare-optimal benchmark. Data used is further shown in 4.2, while 4.3.1 depicts the results of our HRV regulatory model in terms of capacity expansion, congestion and nodal-price convergence. We additionally carry out in 4.3.2 a comparison of the expansion promoted by the HRV price-cap model in Mexico with similar expansion processes in other regions in North America, as well as with the welfare-optimal planning model of an ISO which centrally decides network expansion. Section 5 concludes with hints derived from our analyses on the welfare properties of the PRODESEN plan, as well as with discussion on needed future research.

2. Literature on transmission expansion planning and regulation

In this document, we address welfare-optimal expansion of the Mexican transmission grid under a nodal-pricing system. Two institutional regimes are typical in electricity transmission. The independent-system-operator (ISO) regime, and the transmission-system-operator (TSO) regime. In the ISO regime, generation system-operation and grid-expansion planning are taken care by a system operator while ownership remains within the transmission firm(s). Oppositely, in the TSO regime system operation, planning and ownership of the grid are integrated into a single company.

The Mexican electricity transmission system follows an ISO approach as is the case throughout some Canadian provinces (Ontario, Alberta), various US states (Texas, California, New York, New England, Pennsylvania-New Jersey-Maryland and Mid-West), the Americas (Argentina, Chile, and Brazil), Australia and some European countries (Ireland and Switzerland). In the rest of Europe, the TSO approach prevails (e.g., Nederland, Germany, France and Belgium).

Both in the ISO and TSO regimes, the aim is to efficiently develop transmission networks. Optimal transmission expansion planning and regulation are widely explored in academic literature. Optimal mechanisms for transmission expansion are difficult to design because of the physical characteristics of electricity network flows governed by the Kirchhoff's laws, which cause negative local externalities due to loop flows.[12]

A traditional approach to transmission expansion has been central planning, either carried within a vertically integrated utility or by a regulatory authority. Transmission planning schemes have been ana-

[4] CFE (2015).

[5] U.S. Energy Information Administration (2016).

[6] Integrated transmission planning is not a trivial issue. There are other systems that carry out the transmission expansion process decoupled from generation dispatch, usually resulting in inefficient excessive capacity investments (see Kemfert et al., 2016).

[7] The role in practice of the regulator, CRE, only comes after the expansion planning process carried out by SENER and CENACE in the PRODESEN. We do not explicitly address in this paper how the CRE regulates tariffs. However, our HRV model –that in our paper is mainly used to provide a decentralized benchmark against which to compare the PRODESEN—could provide a qualitative incentive-regulation alternative to regulators. However, again, we do not carry out an explicit comparison between the actual CRE's tariffs and the implied tariffs resulting out from our HRV model. We neither analyze in this paper regulation in a vertical sense that considers regulation of power generation, nor potential-strategic behavior of the regulator. Our two models –the HRV price-cap model and the centralized ISO model—provide welfare results and capacity expansion results. We compare the latter with the expansion results proposed by the PRODESEN.

[8] The CRE has only recently published a set of preliminary transitional transmission tariffs based on three-year CFE's transmission costs. The final regulatory methodology for electricity transmission is expected to be announced in the near future.

[9] The task of carrying out explicit comparisons between the actual CRE's tariffs and the implied tariffs resulting out from the HRV model are again beyond the scope of the current paper. The reason is that such a task requires careful laborious analyses of regional systems. Espinosa and Rosellón (2017) illustrate how such analyses might be performed for the isolated electricity system in Baja California. The comparison of the HRV tariffs with the CRE's tariffs for Southern Baja California is done under two cases on nodal structure, using real data from CENACE. In a first aggregated case, a three-node market is assumed. In a second disaggregated case, a more detailed thirty-one node structure is modelled. The second case allows for more detailed results on planned capacity-increase for each transmission line in the system. Tariffs are calculated by taking into account the fixed tariff resulting from the HRV model as well as congestion rents. Additionally, weights are applied using the same logic as the CRE's tariffs. That is, 70% is considered a charge to consumers, and 30% to generators. Demand projections by SENER are used for 10 years. The expected payoff for consumers is calculated, as well as their savings or excess expenditures. In all cases, the HRV tariffs align better than the CRE's tariffs regarding investment incentives to efficiently expand transmission links as well as on eventually converging to optimal social welfare.

[10] This is explained in more detail below in Section 4.1.

[11] HRV stands for the model in Hogan-Rosellon-Vogelsang price-cap mechanism (Hogan et al., 2010)

[12] The issue of optimal transmission expansion has been addressed through a range of different regulatory schemes and mechanisms that have been proposed and applied (e.g., Léautier, 2000, Kristiansen and Rosellón, 2006, Tanaka, 2007, Léautier and Thelen, 2009, Hogan et al., 2010).

lyzed in various studies, especially under renewable integration processes. For instance, van der Weijde and Hobbs (2012) design a stochastic two-stage optimization model to study transmission planning under uncertainty, and show that ignoring risk in transmission planning for renewables might imply investment decisions assuming inferior expected costs than optimal. Baringo and Conejo (2012) develop a model to categorize new optimal wind projects as well as required network backups, together with a range of subsidies to encourage independent wind power investment. Schroeder et al. (2013) further develop an optimization model to explore future congestion levels with distinct transmission-expansion scenarios. They stress the need of reshaping transmission networks under increasing renewable generation. Egerer and Schill (2015) further study the trade-off between transmission and generation investments in transmission planning using an integrated investment and generation dispatch model. It is shown here show that transmission expansion can be partially substituted by the optimal placing of generation units.[13]

Alternatively, transmission investment decisions could be led in a decentralized way through price regulatory mechanisms ranging from cost-of-service regulation to incentive-price regulation. The Hogan-Rosellon-Vogelsang price-cap mechanism is an example of a decentralized regulatory incentive price-cap regime.[14] It combines merchant and regulatory structures to incentivize the expansion of networks, and promotes network investment with better welfare outcomes than cost-plus regulation or no-regulation at all, even under fluctuating demand and supply conditions as in renewable integration processes.[15] Jenabi et al. (2013) additionally develop a bi-level model for optimal network expansion that anticipates investment of generation firms operating under perfect competition. Grimm et al. (2015) further analyze the long-run impact of the regulatory environment on transmission line expansion and investment in generation capacity by private firms in a liberalized electricity market. Generation investment decisions are made under anticipation of an energy-only market or cost-based redispatch, and results are compared with a first-best benchmark of an integrated central planner problem. It is shown in this study that excessive network expansion results due to the energy-only assumption, while multiple price zones might amend excessive transmission investment. Thus, the nodal pricing Mexican regime is a plus in terms of efficient network investment.

Kemfert et al. (2016) additionally analyze the welfare effects of different network planning approaches on transmission investment. A couple of modeling settings are studied: a “separated” scenario (where there is no trade-off between transmission expansion and generation dispatch), and an “integrated” setting (which allows for such a trade-off). The two models are compared so as to gauge the amount of overinvestment in capacity, and it is shown that an integrated approach to network expansion planning considerably reduces the necessary network expansion as opposed to the separated approach. This question is relevant for the Mexican case where an integrated approach to transmission planning is carried out, as opposed to other international experiences, such as in Germany where that is not the case.[16]

It must be pointed out that, both from a theoretical perspective and in the practice of transmission planning, there is a trade-off between transmission expansion and congestion management. That is, optimal levels of network expansion are usually determined by the minimum level between both congestion management and network-expansion costs. Since congestion management costs decrease and transmission-expansion costs typically increase when new transmission capacity is built, a cost-minimal combination should include both alternatives. Optimal transmission expansion should then not completely remove congestion in the transmission network, but rather optimally balance both substitutes.[17]

3. The PRODESEN plan[18]

3.1. The Mexican transmission system

In 2015 the Mexican electricity sector was mainly based on fossil-fuel generation capacity (79.7%, 246,413 GWh), with the rest of capacity coming from “clean” sources (20.3%, 62,839 GWh).[19] 84% of the total capacity was in hands of CFE (including private IPPs that offer all of their generation to CFE), while the resting 16% capacity belonged to private investors (self-supply, cogeneration, small production and export projects).

The transmission system consists of 53 regions, 49 of them are interconnected, while 4 nodes in northern Baja California region are connected to the US Californian system (CAISO) (see Fig. 1). The remaining 4 nodes conform an isolated group in southern Baja California. In 2015, the total length of transmission lines in tensions from 230 to 400 kV was 53,216 km., and with tensions between 69 and 161 kV was 51,178 km. To keep up with growing electricity demand, CFE recently calculated the need to expand the national network in around 19.3 billion USD of transmission projects, including 28,498 circuit-km of new lines.

3.2. PRODESEN

The 2016–2030 plan for expanding the national transmission system, PRODESEN, relies on a nodal pricing system for the country, and on assumptions on development of generation capacity, as well as demand growth.[20] The specific models used by SENER and CENACE to forecast electricity demand and supply, as well as transmission expansion, are next presented:

3.2.1. Consumption and demand

Electricity consumption is estimated based on the following model:

$$\boldsymbol{\hat{CE}}_{x,y} = \beta_0+\beta_1\boldsymbol{\hat{CF}}_{x,y}+\beta_2\boldsymbol{P\hat{M}}_{x,y}+\beta_3\boldsymbol{\hat{US}}_{x,y}+\beta_4\boldsymbol{P\hat{I}B}_y+\in \tag{1}$$

$$\forall \quad x = 1,\ldots,10;\forall \quad y = 1,\ldots,15$$

$$\boldsymbol{\hat{CE}}_{\mathrm{SENy}} = \sum_{i=1}^{10}\hat{\mathrm{CE}}_{x,y};\forall \quad y = 1,\ldots,15 \tag{2}$$

where:

[13] For further analyses on optimal transmission expansion planning see: Stoft (2006), Oliveira et al. (2005), Sauma and Oren (2006), and Sauma and Oren (2009).

[14] Price caps have been widely used in practice as early as the eighties in the telecommunication sector of Great Britain. During the nineties, price caps were already adopted in regional electricity markets, such as Texas (ERCOT) and Pennsylvania-New Jersey-Maryland (PJM). In Latin America, price caps have been used in the energy markets of Argentina, Brazil, Colombia, Uruguay and Guatemala.

[15] See Rosellón and Weigt (2011), Rosellón et al. (2011), Ruiz and Rosellón (2012), Schill et al. (2015), Egerer et al. (2015), Neumann et al., 2015.

[16] Trepper et al. (2015) further analyze market-splitting in Germany.

[17] Kunz (2013) analyzes the German approach to congestion management and finds that congestion and associated costs increase due to higher renewable generation shares.

[18] Data in this section are primarily based on Cenace (2015, 2016).

[19] Clean sources in Mexico are defined as non-conventional non-fossil fuels, such as hydro, nuclear and renewables (wind, solar, geothermal, biomass, etc.).

[20] Other crucial assumptions are made upon projected GNP, fuel costs, energy consumption, clean and renewable energy goals, natural-gas pipeline infrastructure, and renovation of existing old generation plants. More specifically, PRODESEN considers three possible macroeconomic scenarios in terms of medium, high and low respective increases of fuel prices, GNP, demand, generation investment (including clean technologies) as well as general system investment costs. The medium scenario, for example, considers an estimated annual GNP annual growth of 4.1% in Mexico during 2016–2030, as well as increases of 4.3%, 4.7% and 2.6% in West-Texas-Intermediate (WTI) oil, Mexican-exporting-oil and South-Texas-natural-gas prices, respectively. Further annual increases in 3.7% and 3.4% are assumed during the next 15 years for national demand and consumption growth, respectively, as well as a 13% reserve margin, a 10% discount rate and a 13.5% rate of return.

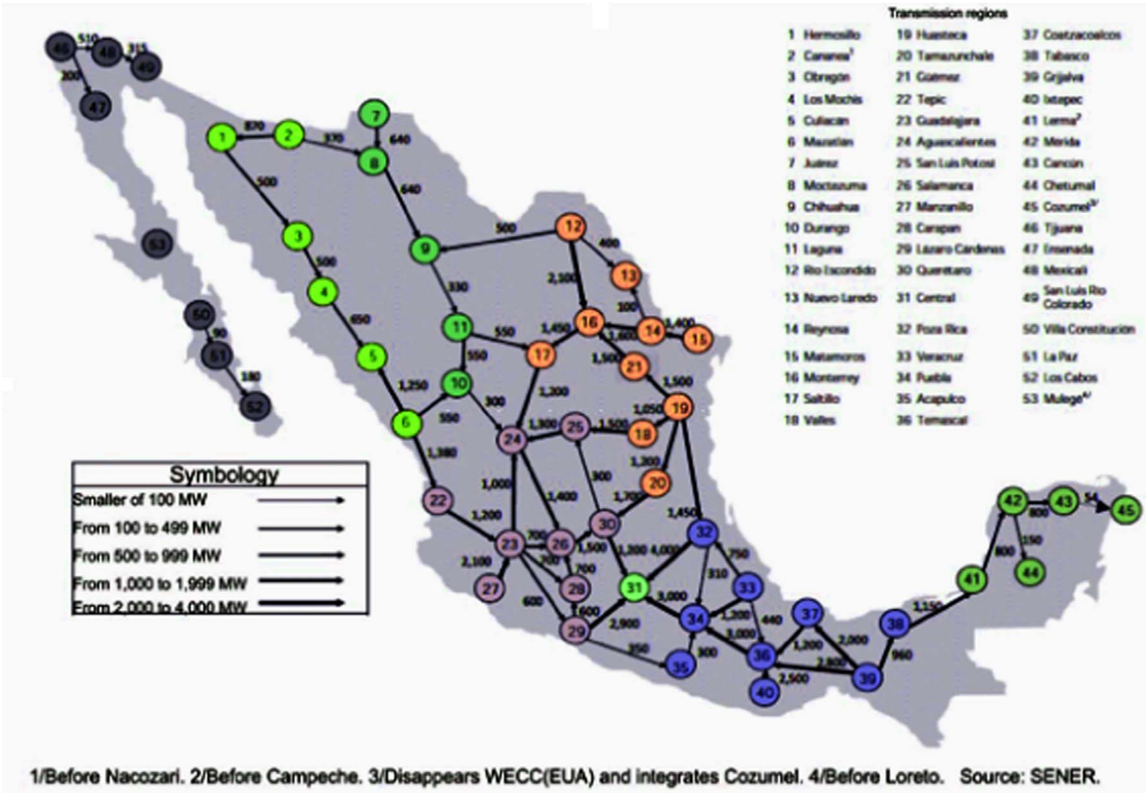

Fig. 1. Transmission regions in Mexico in 2015. (Source: SENER, 2016)

$\hat{CE}_{x,y}$: electricity consumption forecast (GWh/year)
$\hat{CF}_{x,y}$: final consumption forecast (GWh/year)
$\hat{PM}_{x,y}$: average electricity-price forecast ($/kWh)
$\hat{US}_{x,y}$: final consumer forecast (annual average)
$\hat{PIB}_{y}$: gross-internal-product forecast (PIB growth is used to determine the different macroeconomic scenarios: low, medium and high).
x: 1, ..., 10 control regions y: 1, ..., 15 years (1=2016, ... 15=2030)
$\hat{CE}_{SENy}$: annual consumption forecast for the complete national electricity system during year y.

Consumption values are subsequently used to calculate total demand as follows:

$$\hat{DMI}_{x,y} = \frac{\hat{CE}_{x,y}}{hr \times FC_x} \tag{3}$$

$\forall \quad x=1,\ldots,10; \forall \quad y=1,\ldots,15$

$\hat{DMI}_{x,y}$: maximum integrated-demand forecast of control region x for year y (MWh/h).
FC_x: load-factor of control región x.
hr: 8,760 h in a year (8,784 in a leap year).
x: 1, ..., 8 control regions in the national integrated system (SIN).
y: 1, ..., 15 years with available information (1=2016, ... 15=2030).

And then hourly demand is obtained according to:

$$\hat{DH}_{x,h} = \frac{\hat{DMI}_{x,y}}{hr \times Cr_{x,h}} \tag{4}$$

$\forall \quad x = 1,\ldots, \quad 8; \forall \quad y = 1,\ldots,15;$

$\forall \quad h = 1,\ldots,24$

$\hat{DH}_{x,h}$: hourly demand for control region x (MWh/h).
$Cr_{x,h}$: hourly reference curve for region x.

3.2.2. Generation capacity growth

Regarding the generation-expansion planning process (PIIRCE), this is based on a dynamic *Mixed Integer Linear Program* whose results determine new generation plant locations considering disposability, technology types, capacities, and subject to system restrictions:

$$\text{Min}\{C_{INV}+C_{O\,\&\,M}+C_{COM}+C_{ENS}\} \tag{5}$$

subject to:

$$\left[\sum_{i=1}^{N(y)} EG_{i,y}\right] + ENS_y = C_y ;\forall \quad y=1, \quad \ldots, \quad 15 \quad \textit{Energy Balance} \tag{6}$$

$$PG_i^{mín} \le PG_i \le PG_i^{máx} \text{ Thermal power limits} \tag{7}$$

$$PG_i \le PG_i^d \text{ Wind and solar power limits} \tag{8}$$

$$\sum_{i=1}^{N(y)} CI_{i,y} \ge d_{B,y}\left(1+\frac{MR_y}{100}\right); \forall \quad y=1, \quad \ldots, \quad 15 \text{Planning reserve} \tag{9}$$

$$\sum_{y=1}^{15} \sum_{i=1}^{i(y)} CI_{i,y}^{j} \le R_j \textit{ Clean resource potential} \tag{10}$$

$$\sum_{i=1}^{I(y)} EGL_{i,y} \ge M_y \sum_{i=1}^{N(y)} EG_{i,y}; \forall \quad y=1, \quad \ldots, \quad 15 \quad \textit{Clean energy goals} \tag{11}$$

Where:

C_{INV}: net present value of investment costs.
$C_{O\,\&\,M}$: net present value of operation and maintenance costs.
C_{COM}: net present value of fuel costs.
C_{ENS}: net present value of non-supplied energy
$EG_{i,y}$: energy generated by the generation unit i in year y [MWh].

ENS_y: energy not supplied in year y [MWh].
$PG_i^{mín}$: lower operating power limit for generator i [MW].
PG_i: power generated by generator i [MW].
$PG_i^{máx}$: upper operating limit for generator i [MW]
PG_i^d: maximum power available based on primary resources [MW]
$CI_{i,y}$: installed capacity of unit i in year y [MW].
R_j: estimated resource potential j [MW].
$l(y)$: number of clean generators in year y
EGLi,y: energy generated by unit i in year y [MWh].
M_y: clean energy goal in year y [%]

Through the use of these models, in its medium scenario SENER estimates a need of 57,122 MW of additional generation capacity for 2016–2030, 38% of which should come from conventional technologies (21,706 MW), and 62% from clean technologies (32,552 MW). It is also estimated that CFE (and its IPPs) will cover 35.5% of these investment needs, while 33.3% should be covered by private entrants to the new electricity market.[21] The yearly expected increases in generation capacity by technology from 2016 to 2030 are presented in Fig. 2.

3.2.3. Transmission expansion

The transmission planning process PRODESEN for 2016–2030 takes as given these last estimations on generation growth. Energy Mexican authorities claim that PRODESEN is in turn based on a (typical) power-flow model that minimizes transmission expansion costs under general assumptions.[22] The essential model that *appears* to be used by the Mexican ISO should be similar to the one presented in Eqs. (18) through (21) below.[23]

Fig. 3 illustrates the main PRODESEN's results on transmission expansion at a national level. It can be seen that transmission capacity increases will be needed in the Northern (node 5, 6, 8, 9, 11, 12), North-Eastern (nodes 2, 4, 10, 14) and Southern regions (nodes 1, 7, 13) of the country.[24] The interconnection of the continental integrated transmission system and the Baja California's isolated systems is a priority, as well as capacity increase in cross-border connections with the USA and Central America (Belize and Guatemala). This expected increase in transmission capacities should result in a decrease of congestion in the Mexican network. Additionally, Fig. 4 presents the estimation made by SENER for the expected decrease in national nodal prices by 2020.

4. Models, data and results

In this section, we present two models that suggest ways to evaluate the welfare efficiency properties of the PRODESEN plan.[25] In subsection 4.1 we present an incentive HRV price-cap regulation model that is applied to the Mexican electricity grid so as to achieve welfare-optimal network expansion. In Section 4.2, we show the data we had access to, and in 4.3.1 we present the results of simulations with the HRV model. In 4.3.2 we further develop a model of a centralized ISO that provides a welfare-optimal benchmark against which to compare the results of the HRV model, as well as the case of no expansion in networks..

4.1. Incentive model

We next employ a quantitative bi-level power-flow modeling approach. The focus is to propose an incentive methodology that could be used to evaluate the welfare characteristics of the PRODESEN and, eventually, to regulate electricity transmission tariffs in Mexico. We rely on Hogan et al. (2010) and Rosellón and Weigt (2011) a model which combines merchant and regulatory approaches, redefines the output of transmission in terms of point-to-point transactions (or, equivalently, in terms of FTRs[26]), and applies Vogelsang (2001) for meshed electricity networks so as to efficiently lead the expansion of an electricity network to convergence to Ramsey-Boiteux equilibrium. For the reader's convenience, we next make a transcription of this model.[27]

The HRV model is a bi-level programming model with “upper” and “lower” levels. The definition of variables is as follows:

k_{ij}^t= line capacity between node i and node j at time t.

F^t = t.
d_i^t= demand at node i at time t.
g_i^t= generation at node i at time t.
g_i^{max}= available maximum generation capacity at node i.
N^t = number of consumers at time t.
$p(.)$ = demand function
$c(k)$ = transmission cost function in terms of capacity.
RPI = Inflation adjustment factor.
X = efficiency adjustment factor.
w = weight.
mc_i= marginal generation cost at node i.
pf_{ij} = power flow on the line connecting i and j.
q_i = net injections at node i.
p_i^t= price at node i in period t.
π = profits of the Transco

4.1.1. Upper-level problem

We rely on Rosellón and Weigt (2011)’s reformulation of Hogan et al. (2010) in terms of congestion rents as

[21] The rest would be covered by self-supply, cogeneration and small production projects.

[22] As in Rosellón and Weigt (2011).

[23] The concrete detailed transmission expansion modeling program was not released in the 2016 edition of the PRODESEN (see CENACE, 2016). However, talks that we had with government officials from SENER and CENACE confirm that a power-flow model –similar to the one described in Eqs. (18) through (21) below– is actually used by CENACE in its transmission-expansion planning process of PRODESEN.

[24] Especially in the following links: Oriental-Peninsular, Huasteca-Güémez, Los Mochis-Culiacán, Mazatlán-Tepic, Moctezuma-Chihuahua, Reynosa-Monterrey, Saltillo-Aguascalientes, Temascal-Centro, Interconexión SIN-Baja California Norte, Interconexión SIN-Baja California Sur, Interconexión México-Guatemala.

[25] It must be pointed out that we do not address in this paper the trade-off between generation and transmission expansion. The generation expansion forecasts (PIIRCE) carried out by SENER are used in the PRODESEN planning as given values so as to determine expansion in transmission links. We do the same in our modeling strategy.

[26] An FTR is a contract that allows its owner the right to gather payments when congestion takes place in an energy market. An FTR is typically characterized in accordance to: 1) an injection node and a withdrawal node that characterize the point-to-point direction of the electricity flow and the contract, ii) a megawatt (MW) award that remains invariable for the length of the contract, and iii) a life period. FTRs are habitually of two types: FTR-obligations and FTR-options. With an FTR obligation the holder has the right to collect payment (when congestion takes place) or the requirement to pay (when congestion in network takes place in the opposite direction as originally defined in the FTR contract). The payment is provided by the difference in prices between the injection node and the withdrawal node times the agreed contractual amount of MW. In dissimilarity, FTR options allow only the non-negative gains to its owner since there is no charge when congestion occurs in reverse direction of the FTR. FTR markets have been implemented in the northeast US power markets since the late 1990s. In other countries, there has also been intense discussions on the need for congestion hedging from transmission price risk, such as in the case of New Zealand, where nodal prices were implemented as early as 1989. Notwithstanding, the *initial* allocation of FTRs in newly created nodal-price systems has been highly disputed as part of market liberalization processes in various countries. In the US Northeast FTR markets in Pennsylvania, New Jersey, Maryland, New York and New England have allowed; (i) to compensate market “losers”, (ii) to reduce the risk for players since they are protected against potential price impacts, and iii) help to make electricity markets financially mature (see Adamson and Parker, 2013). Other countries that have implemented FTR mechanisms include Australia, Colombia, Peru, and, very recently, Mexico.

[27] The reader may of course consult many more details of this model in the reference sources: Rosellón and Weigt (2011), Hogan et al. (2010), and Vogelsang (2001).

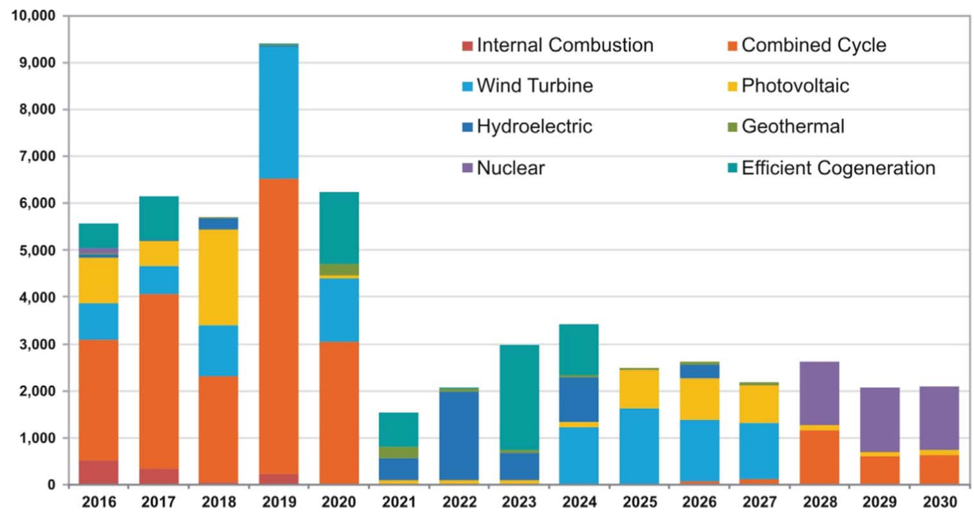

Fig. 2. Main planned generation units for 2016–2030. (Source: SENER, 2016).

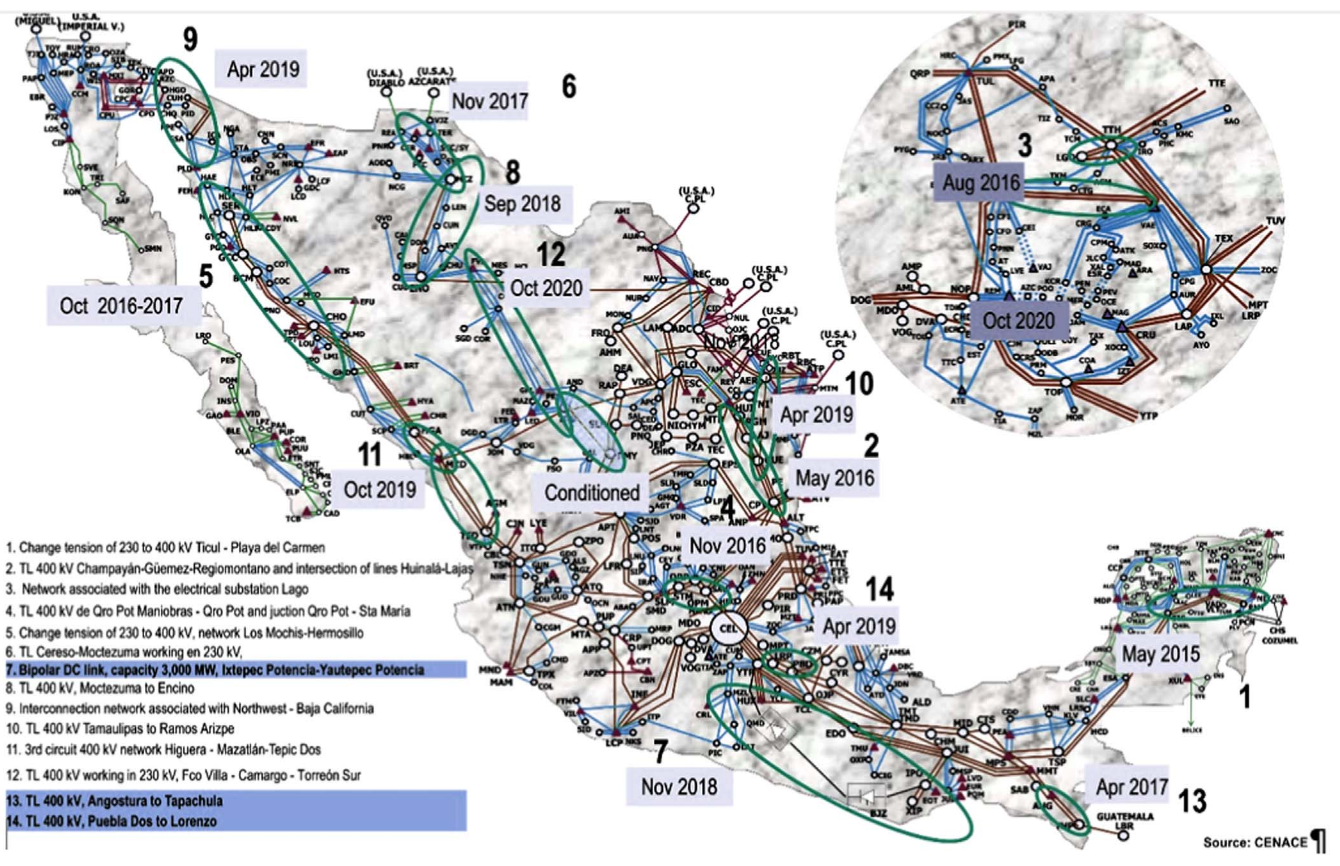

Fig. 3. Electricity transmission capacity expansion in Mexico for 2015–2020. (Source: CENACE, 2015).

$$\max_{k,\,F} \pi = \sum_{t}^{T} \left[\overbrace{\sum_i (p_i^t d_i^t - p_i^t g_i^t)}^{A} + \overbrace{F^t N^t}^{B} - \sum_{i,j} \overbrace{c(k_{ij}^t)}^{C} \right] \tag{12}$$

subject to

$$\overbrace{\frac{\sum_i (p_i^t d_i^w - p_i^t g_i^w) + F^t N^t}{\sum_i (p_i^{t-1} d_i^w - p_i^{t-1} g_i^w) + F^{t-1} N^t}}^{D} \le \overbrace{1 + RPI + X}^{E} \tag{13}$$

In (12) congestion rent A is expressed in terms of nodal-price differences between loads and generators: $p_i d_i - p_i g_i$. Term B denotes revenues from fixed charges, while term C represents cost of expanding transmission that the Transco bears when deciding about the capacity *kij* between two nodes according to a cost function *c(.)* (step 2 in the sequence). We consider a total time framework of T periods and assume perfect information neglecting uncertainty about demand and generation. (13) shows the RPI-X weighted price-cap constraint (E) over transmission two-part tariffs (D). The prices (p) and quantities (g) of each period are linked with a weight mechanism parameter w (such as Paasche or Laspeyres weights), and are subject to a cap defined by the regulator and considering inflation (*RPI*) and efficiency (*X*) parameter factors.

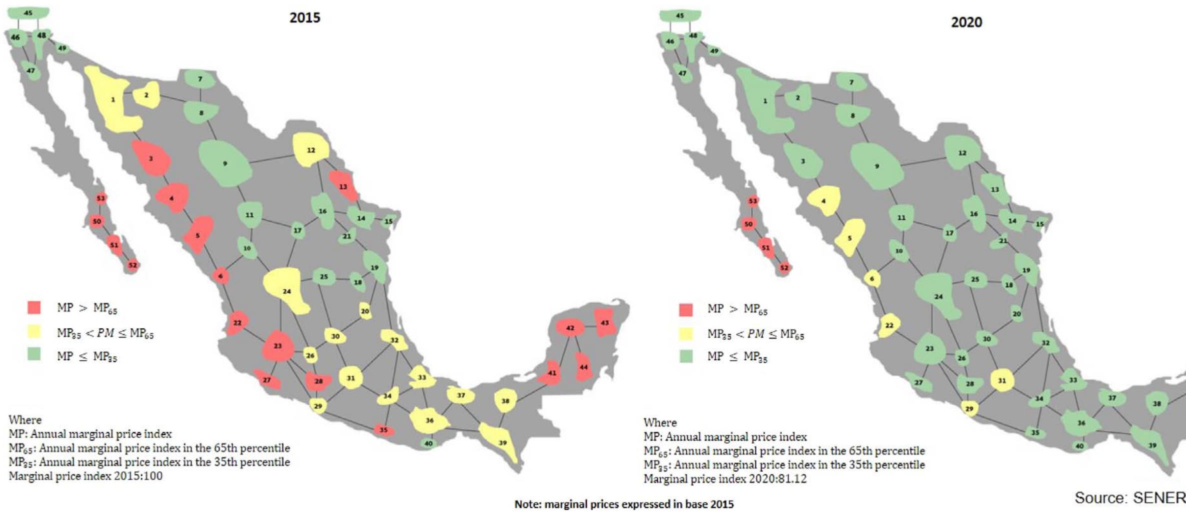

Fig. 4. Expected decrease in electricity nodal prices in Mexico 2015–2020. (source: SENER, 2016).

4.1.2. Lower-level problem

An ISO maximizes social welfare W given restrictions on generation capacity, transmission-line capacity, and energy balance. It also makes sure that all electricity-engineering technical restrictions are met in a market with linear demand and constant generation marginal cost at each period t. The welfare maximizing problem for the ISO then looks like:

$$max/d,\ gW = \sum_{i,t} \left(\int_0^{dt/i} p(dt/i)\mathrm{d}dt/i \right) - \sum_{i,t} mc_i g_i^t \tag{14}$$

subject to

$$g_i^t \le g_i^{tmax} \quad \forall \ i, t \tag{15}$$

$$\left| pf_{ij}^t \right| \le k_{ij}^t \quad \forall \ i, j \tag{16}$$

$$g_i^t + q_i^t = d_i^t \tag{17}$$

\Restriction (15) means that generation g at each node i cannot be greater than a predetermined maximum generation capacity $g^{\max}$. Inequality (16) shows that energy flow pf_{ij} in a transmission link between nodes i and j may not exceed transmission-line limit k_{ij}. Last restriction (17) indicates that load at each local node is to be satisfied by generation supply at such a node, or from power imports from other nodes.

In the HRV model, convergence to a steady-state Ramsey-Boiteaux equilibrium is basically then achieved by means of a price cap on two-part tariffs of a Transco that promotes the intertemporal rebalancing of its fixed and variable charges within a process where potential loss of congestion rents (due to the expansion of the network) is compensated by controlled increases of the transmission capacity fixed fee.[28] The regulatory model is further combined with a power-flow model where the ISO achieves both technical flow simultaneous feasibility as well as financial revenue adequacy in the network system.[29]

Although, to our knowledge, the HRV mechanism has not been formally applied in practice, many countries use some sort of incentive regulation to promote transmission expansion investments. The Netherlands is an example.[30] Likewise, the HRV mechanism can provide benchmarks against which various planning and regulatory transmission regimes might be compared, in order to gauge its welfare properties (as is the case of the current paper). The logic that guides the expansion of networks under the HRV mechanism then works best under nodal pricing systems. Therefore, the applications of the HRV mechanism in European cross-border interconnector systems (eg., Rosellón and Weigt, 2011, and Schill et al., 2015) have first modelled those systems as nodal systems, and apply the HRV mechanism. Another example is the work in Kemfert et al. (2016), where the German uniform pricing scheme is transformed into a nodal pricing system so as to study the implications of the regulatory system there. This in turn provides a benchmark to evaluate the welfare characteristics of systems without nodal spot pricing.

In the same fashion as in HRV and Rosellón and Weigt (2011), we follow the approach of an economic dispatch within a meshed DC-network topology. The Transco maximizes profits at each time t relying on the welfare-optimal solution derived from the ISO's economic dispatch program. Numerical iterations in the lower-level problem provide the optimal values of demand d, generation g and nodal prices p at each node i, which in turn feed up the upper-level program so as to determine the values of capacity K, and the corresponding fixed charge F. For simplicity, RPI and X factors are assumed to be equal to zero.

This mechanism is applied to the Mexican transmission system during 8 periods (2012–2020) assuming linear inter-node transmission cost-functions, an expanding cost value of \$130 per MWkm, a linear demand with price–elasticity value of − 0.25 at each reference node, and a depreciation factor of 8% (Table 1). A Price cap is set over the transmission two-part tariff weighted by previous period *Laspeyres* weights. Hourly results obtain as outcomes.[31]

4.2. Data

The application of the above model to the Mexican electricity

[28] The reasons for convergence of the HRV mechanism date back to the original Vogelsang (2001) work. The intuition behind is that this mechanism makes the marginal-revenue of expansion higher than the marginal revenue coming from congestion rents, so that the fixed part of the tariff compensates for the foregone congestion rents when the network is expanded. The HRV mechanism works even under low congestion (or excess capacity). In such a case, the variable (congestion) charge would be low (to encourage consumption of network service), and the fixed charge is high. The mechanism works the other way around whenever congestion is high. The rebalancing is such that welfare increases (and congestion decreases) along the convergence path to a welfare-optimal steady state.

[29] Technical simultaneous feasibility is achieved for electricity flows that meet the capacity and energy-balance constraints in a power-flow model. Hogan (1992) shows that simultaneous feasibility implies revenue adequacy of an electricity system.

[30] Glachant et al. (2013)

[31] In each period, the Transco's revenues are multiplied by 8760 so as to represent yearly revenues. We do not include in our model precise hourly variations, especially due to renewable generation sources such as wind and PV solar. We neither consider precise time demand fluctuations, such as peak-non-peak or winter-summer variations. Our model is only a simplified version and, therefore, only a rough estimation of a real economic dispatch. However, we believe that this is a first independent approach to start studying the Mexican reform using an established model as reference.

Table 1.
Simulation values for all study cases.
Source: Own elaboration. The assumed values follow Rosellón and Weigt (2011), where a sensitivity analysis is carried out.

Values	
Number of periods	8
*Cost**	linear
Inter-node cost functions	$c_{ij}^{t} = c_{o} \cdot (k_{ij}^{t} - k_{ij}^{t-1}$
Co (transmission line expanding cost value)	130 \$/MWkm
Demand	linear
Price elasticity of demand value	−0.25

Table 2
Generation average costs in Mexico[a].
Source: Own elaboration based on CFE (2011).

Technology	*USD per MWh (average)*
Turbine Simple Cycle	140.883
Natural Gas Turbine	153.490
Turbine Combined Cycle	58.148
Internal Combustion	159.555
Coal	67.540
Nuclear	91.270
Geothermal	94.765
Hydroelectric	100.477
Wind Turbine	81.160
Photovoltaic	189.740

[a] Average costs assumes baseload operation

system comprises an aggregated representation of the Mexican power system (Fig. 1) that is inter-temporally optimized.[32] We consider 85 main generation plants in the country (see CFE, 2007, 2008 and 2011, and CENACE, 2016).[33] Price in each generation plant is equivalent to an approximation of total (fixed and variable) costs[34] reported by CFE (Table 2).

For our simulations, we consider a simplified transmission network topology in Mexico which comprises 54 aggregated nodes, and 68 lines with capacity ranging from 100 to 4000 MW (Fig. 1).[35] Nodes located in the central region of the country are part of a meshed network, while nodes at the north and south extremes generally belong to radial-line structures.

4.3. Results

4.3.1. Nodal prices, and transmission congestion and expansion

From the lower level problem, we identify the congested transmission lines for nodes located throughout the country, but especially in North, North-Eastern and South of the national transmission network (Fig. 5). Highest nodal prices correspond to nodes located throughout the country (many in the north) which comprise important industrial areas with high load requirements: Chihuahua (9), Moctezuma (8), Nacozari (2), Hermosillo (1), Obregón (3), Los Mochis (4), Mazatlán (6), Laguna (11), Saltillo (17), Durango (10), Aguascalientes (23), Manzanillo (26), Río Escondido (12), Monterrey (16), Reynosa (14), Matamoros (15), San Luis Potosí(24), Huasteca (19), Poza Rica (31), Veracruz (32), Puebla (33), Temascal (35), Lazaro Cárdenas (28), Coatzacoalcos (36), Tabasco (37), Grijalva (38), Mérida (40) y Cancún (41). Our estimated congestion values somewhat diffe from the ones in PRODESEN, Fig. 4, year 2015. One reason for such a difference might be that we only had access to data according to the 85 generation plants (60, 323 MW) with 54 nodes. The generation plants in PRODESEN (CENACE, 2016) is based on approx. 80, 000 MW initial data, and a corresponding network topology with 53 nodes.

The application of the HRV mechanism is shown to promote the expansion of transmission lines, decrease the energy cost in the north of the country, and incentivize nodal-price decreases in central regions. Prices in southern regions are however increased, but such an increase is compensated by price decreases in other regions. Fig. 6 shows the evolution of nodal prices over the 8 periods considered in our simulation. During the first period, nodal prices significatively diverge consequently resulting in high levels of transmission congestion rents. Nodal-price convergence starts to occur as early as after the first period, being more notable in the eight period. Initial average nodal price starts in USD 78. The average nodal price at the end of our simulation becomes USD 49, representing a decrease of 37% compared with the initial simulation period. Price increases in nodes with initially low generation costs are of course compensated with price reductions in resting nodes.

Expansions in transmission links follow similar intertemporal dynamics to nodal prices: an extensive capacity increase during the eight periods, and then gradual convergence to limit capacity in the last period. Nodes that experimented considerable price decreases are located in the north (N10, N11, N12, N14) and in the center (N23, N24, N32, N35). In the Pacific coast nodal prices increase (N1 through N6) as well as in the south (N39). Nodes that increase nodal prices are: N20, N21, N22, N29, N30, N49, N45, N46, N47, N51, N52 and N53.

Fig. 7 shows the application of the HRV mechanism over eight periods (2012–2020). Prices decrease, and result generally in lower levels of transmission congestion. Our estimated congestion approximate (but still differ) from the values from the PRODESEN, (see Fig. 3 above).

However, the estimated congestion values for 2020, calculated with the model of a centralized ISO over eight periods (Fig. 8), show still an imperfectly approximation (but more accurate) to the ones in PRODESEN (Fig. 4), as well as lower levels of transmission congestion compared to our HRV simulation (Fig. 7).

4.3.2. Welfare

One relevant further question is the impact on social welfare due to the application of the HRV mechanism to incentivize the expansion of the Mexican transmission system. We present now such an analysis and, taking advantage of previous studies, compare it with analogous analyses for other systems in North America; namely, the electricity systems in Ontario, Canada, and in Pennsylvania, New Jersey, Maryland (PJM), United States.[36]

We also gauge for the three systems transmission capacity and average price changes derived from expansions in transmission links, and compare such values with a welfare-benchmark case of an ISO that centrally plans in each system the expansion of respective transmission grids. In this last setting, the ISO maximizes welfare (understood as the sum of consumer surplus plus producer surplus plus congestion rents) minus transmission expansion costs:

$$\max_{d,g} \quad W = \sum_{i,t} \left(\int_{0}^{d*} p_i(d_i^t) \mathrm{d}d_i^t \right) - \sum_{i,t} mc_i g_i^t - \sum_{i,j} c(k_{ij}^t) \textit{ ISO objective function} \tag{18}$$

s.t.

[32] This simplified model version strategy was chosen due to the available information that we were able to obtain from CENACE and SENER.

[33] The capacity/generation share for the 85 generation plants is as follows: combined cycle 50,66%, hydro 11.15%, coal 12.18%, steam 13.79, nuclear 3.33%, wind 3.11%, turbo gas 2,87%, geothermal 2,.02%, internal combustion 0.73%, biomass 0.08%, biogas 0. 04%, and PV solar 0.05%.

[34] The obtained data are not homogeneous for same types of technology. As opposed to Rosellón and Weigt (2011), prices were averaged.

[35] To simplify the analyses we use power, as opposed to MVA, so as to determine transmission-line limits.

[36] See Rosellón et al. (2011), and Rosellón et al. (2012).

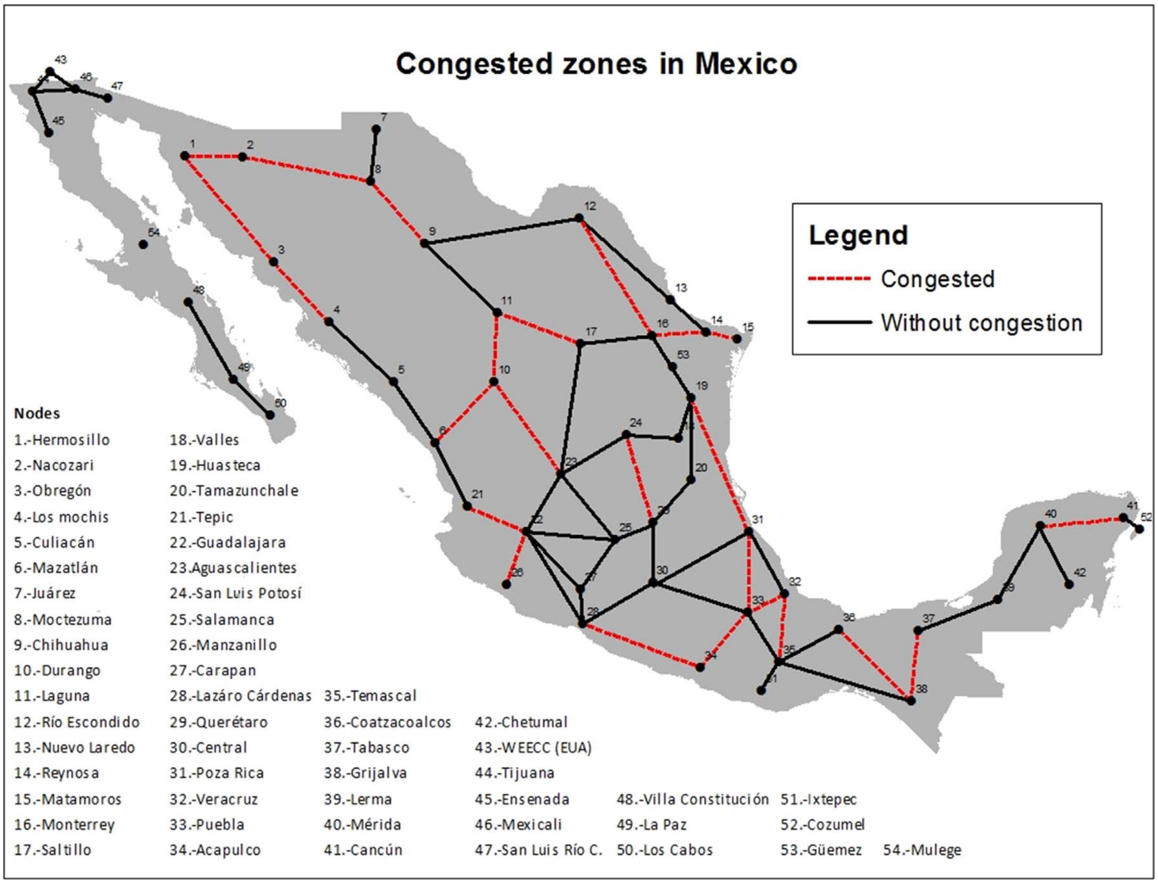

Fig. 5. Congested zones in Mexico 2015. (Source: Own elaboration).

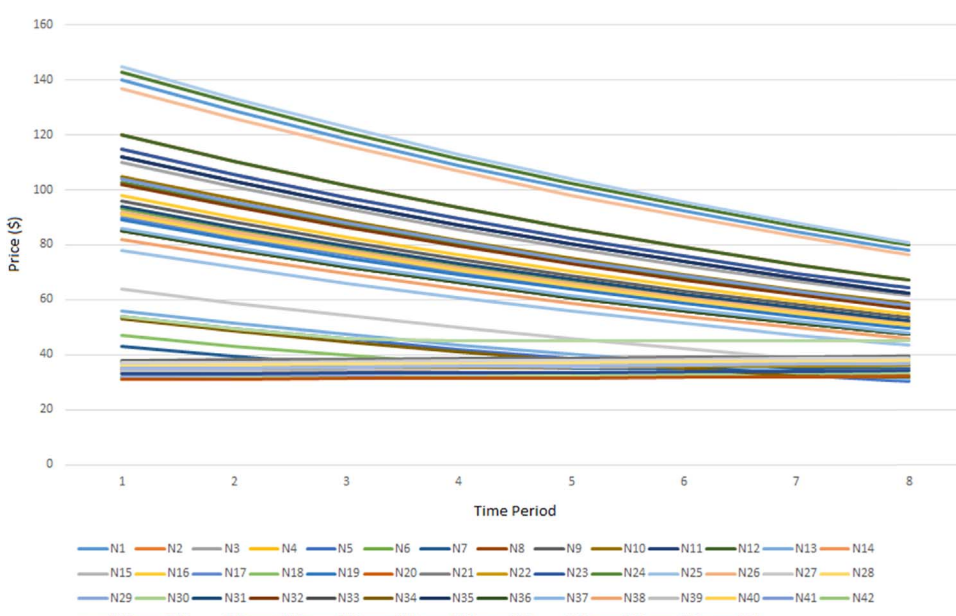

Fig. 6. Nodal-price developments in Mexico (2015–2023). (Source: Own elaboration).

$$g_i^t \leq g_i^{t,\max} \quad \forall\ i,\ t \ \textit{Generation constraint at node I} \tag{19}$$

$$\left|pf_{ij}^t\right| \leq k_{ij}^t \quad \forall\ ij \ \textit{Line flow constraint between i and j} \tag{20}$$

$$g_i^t + q_i^t = d_i^t \quad \forall\ i,\ t \ \textit{Energy balance constraint at nodeI} \tag{21}$$

where:

W: social welfare.
t: period (t=0,1,2,3.....)
d_i: demand at node i
g_i: generation at node i
$g_i^{t,\max}$: max generation at node i at period t
mc_i: marginal cost at node i
$p_i(.)$: inverse demand function at node i

Fig. 7. Congested zones in Mexico 2020 (HRV simulation). (Source: Own elaboration).

k_{ij}: available transmission capacity from node i to node j
q_i: net injections at node i
$c(.)$: transmission cost function
pf^t_{ij}: power flow on the lines connecting nodes i and j at time t

Resulting simulations are grouped into Table 3.[37]

Both for the HRV and the-centralized-ISO models, Table 3 shows for the three systems general increases in consumer and producer surpluses, decreases in congestion rents and average prices, and increases in network capacity and total welfare as compared to the case of no-extension.[38] Furthermore, in the three simulations the use of the HRV mechanism promotes convergence to the centralized ISO welfare-optimal benchmark. In the case of Mexico, compared to PRODESEN's forecasts in Fig. 4, year 2020, the HRV mechanism seems to converge to decreased nodal-price differences at lower pace. Likewise, our analysis hints that the PRODESEN plan is in fact converging to the welfare-optimal planning of program (18) subject to (19) through (21).[39]

5. Conclusions and policy Implications

In this paper, we gathered detailed information –task that proved to be complex in practice– from the Mexican electricity system so as to evaluate with our own independent models the power-flowed planning process to expand the transmission grid, something that the PRODESEN claims to do. This information also allowed us to test the HRV model at a national level. Using our own power-flow model, we compared the essence of what the PRODESEN claims to do with the HRV efficiency measure. We were also able to disentangle in some detail how the PRODESEN works, including the previous initial modeling to forecast generation expansion, PIIRCE. A pending future task is of course getting enough information to actually contrast the real PRODESEN's transmission expansion values against our more realistic results.

Our formal analyses in this document however suggest clues on the efficiency properties of the PRODESEN plan, although these should be taken with reservation given the aggregated nature of the Mexican nodal-price system that we had to assume. Although our initial estimated congestion values for 2015 –calculated with the model of a centralized ISO (program 18, subject to 19–21)—imperfectly approximate the ones in PRODESEN (Fig. 4, year 2015), our results hint that the PRODESEN plan is in fact converging to the welfare-optimal benchmark planning values by 2020 of the centralized-ISO program in terms of capacity expansion, congestion rent, consumer and producer surplus as well as nodal-price differentials.

Additionally, we also showed that incentive price-cap regulation converges to optimal welfare transmission expansion for the Mexican transmission grid. However, compared to PRODESEN's forecast in Fig. 4, year 2020, the HRV mechanism seems to converge at lower pace to decreased nodal-price differences. This is also true when the HRV mechanism is compared to our centralized ISO model. The mechanism intertemporally evolves gradually at lower pace towards convergence to steady-state equilibrium as compared to an ISO that centrally makes expansion decisions solely within maximization of power flows. This result is in line to analogous previous research carried out for transmission systems elsewhere (e.g., Ontario, PJM, Peru, and North Western Europe) where convergence tightens as more periods are

[37] Please note that this welfare comparison is carried out with illustrative purposes only, since the expansion periods for Mexico, Ontario and PJM differ.
[38] The no-extension case should not be interpreted as a "business-as-usual case" (we thank an anonymous referee for this observation).
[39] The centralized-ISO's welfare, consumer and producer-surplus outcomes in Table 3 might be interpreted in this paper as a proxy for the Prodesen's welfare results.

Fig. 8. Congested zones in Mexico 2020 (Centralized ISO simulation). (Source: Own elaboration).

Table 3.
Comparative welfare results for Mexico (2012–2020), PJM and Ontario (2006–2026).
Source: Own elaboration based on Rosellón et al. (2011) and Rosellón et al. (2012).

	Network without expansions			*Hybrid regulatory mechanism (HRV)*			*Centralized ISO*		
	México	*PJM*	*Ontario*	*México*	*PJM*	*Ontario*	*México (e.g. PRODESEN)*	*PJM*	*Ontario*
Consumer surplus (MioUSD/h)	2.43	6.53	0.83	2.95	6.63	0.89	3.012	6.67	0.96
Producer surplus (MioUSD/h)	0.102	0.36	0.051	0.231	0.59	0.087	0.262	0.64	0.105
Congestion rent (MioUSD/h)	0.005	0.067	0.013	0.014	0.01	0.00104	0.0135	0.006	0.0009
Total social welfare (MioUSD/h)	2.537	6.957	0.894	3.195	7.23	0.978	3.287	7.316	1.0659
Total network capacity (GW)	10.26	35.8	2.52	15.77	50.83	4.536	16.42	52.83	4.74

considered. Convergence to welfare-optimal values is more perfect when more periods are considered. Such values characterize a steady state where network congestion and, hence, nodal price differentials reach their minimum value due to transmission network expansion.[40]

The policy implications of our analysis are clear. Since it is based on a combined generation-cost-minimizing and transmission power-flow model –which determines transmission capacity expansion projects based on an integrated approach to transmission expansion and generation dispatch— the PRODESEN plan seems to provide a reasonable planning to efficiently guide the development of the Mexican network. However, our promising results on the application of the HRV mechanism in order to lead transmission expansion investment in Mexico also strongly suggest that the CRE should consider incentives in its future transmission tariff regulatory methodologies, as opposed to its currently in place cost-plus regime to regulate network investments. There is evidence that lack of incentives to actual performance of TSOs and Transcos might result in much less allocative and distributive efficiency than what a typical benevolent regulator would wish (Kemfert et al., 2016).

Future research work should formally analyze in more detail the combination of transmission planning, considering more atomization of the nodal-price Mexican system too. As argued before, the work presented in this paper relied on a stylized aggregated nodal system due to restricted information. Likewise, network planning modeling should be combined with alternative congestion management approaches, like redispatch of renewable and conventional generation. Moreover, the welfare implications of our analyses relied on a perfectly competitive electricity market under perfect information. However, in practice market participants may react to institutional changes by altering their bidding strategy.

[40] See Rosellón and Weigt (2011), and Schill et al. (2015).

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