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Restructuring Saudi Arabia's Power Generation Sector: Model-Based Insights

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Key Points

Saudi Arabia plans to reform and privatize its power generation sector as part of the Kingdom's Vision 2030. To provide analytical insights, we developed a model that simulates the restructuring of the electricity market, along with reforming fuel prices to an energy equivalent of $3/MMBtu. We find that:

In all the scenarios that we study, market restructuring associated with fuel price reform delivers an aggregate economic surplus of more than $4 billion. This is mostly because consumers are paying more for their electricity. However, if all firms in the power market behave competitively, the government's saving in fuel subsidies exceeds the loss in consumers' surplus. This means there is room to implement a compensation scheme that mitigates the increase in costs to the consumer.

There is, at least in theory, potentially significant room for price manipulation by large power-generating companies; as such, elimination of market power through competition or regulation is particularly relevant at peak demand times.

To the extent that the difference between peak and baseload marginal costs is reflected in electricity prices, reforming fuel prices results in an increase in the market value of SEC's existing assets due to higher rents on production capacity. This seems to justify reforming fuel prices prior to restructuring the market in order to maximize government revenues from privatizing existing assets.

We show that introducing a capacity market has only a small effect on peak electricity prices but can significantly increase reserve margins and supply reliability.

Executive Summary

Saudi Arabia plans to reform and privatize its power generation sector as part of its Vision 2030. International experience shows that it will face two challenges: achieving sufficient supply reliability during peak demand and reducing the potential for price manipulation through the exercise of market power by electricity producers. Restructured markets in the Americas and Europe have had to address this market power and introduce additional market instruments to incentivize investments sufficiently to meet reliability requirements.

To provide analytical insights, we developed a model that simulates the restructuring of the electricity market. We assume that the Saudi Electricity Company's (SEC) existing generation assets are unbundled and equally distributed to four new generation companies (Gencos). The model includes an electricity market and – in some scenarios – a capacity market, both with zonal pricing in four operating areas, the possibility of new entrants, a transmission system operator (TSO) who manages the electricity network and a principal buyer that designs and operates auctions for capacity and electricity. Also, arbitrageurs who buy and sell electricity which eliminates price distortions between regions. Wholesale prices are assumed to be passed on to consumers.

To describe different possible market outcomes, we designed several scenarios calibrated to Saudi Arabia's data projected to the year 2020, and we compare them with a business as usual (BAU) scenario that captures the current market structure. In the BAU scenario, fuel prices are administered, the expansion of private generation firms is restricted and the principal buyer uses long-term power purchase agreements (PPAs). In the other scenarios, fuel prices are partially or fully deregulated, generation is privatized and firms bid into a daily auction for electricity. To assess the potential impact of price manipulation we introduce scenarios where the large Gencos exercise market power, as well as scenarios in which all firms operate in perfect competition with no room for price manipulation.

We find that the elimination of market power through competition or regulation is particularly important at peak demand times when competition is very limited and price spikes increase the profits of baseload producers. By reducing the fixed cost of plants, especially among small companies operating at low utilization rates, a capacity market can promote competition among peak generators and reduce electricity prices during peak demand.

Table 1 summarizes results for three scenarios in which all fuel prices are partially deregulated to an energy equivalent of \$3/MMBtu. The values in parentheses represent the percent difference from BAU. In the first two scenarios, there is only an energy market (no capacity market), all firms behave competitively in the Competitive Energy Market scenario, while the large Gencos exercise market power in the Cournot Energy Market scenario. The Capacity Market scenario adds a capacity auction to the Cournot Energy Market scenario.

The fuel subsidies are measured as the difference between the international oil price (assuming \$58 per barrel) and the administered prices paid by the generators. Consumer surplus measures the value that consumers get for electricity beyond the price they pay. It is calculated from estimates of how consumers' electricity demand reacts to price changes. The total surplus is equal to firms' profits plus consumer surplus minus fuel subsidies. The

Table 1. Change with respect to BAU scenario.

Scenario	Average Energy Price, $/MWh	Average cost, $/MWh	Firms' Profits, billion $	Fuel Subsidies, billion $	Consumer Surplus, billion $	Total Surplus, billion $
Competitive Energy Market	18 (90%)	16.6 (91%)	0.53	-11.7	-7.91	4.3
Cournot Energy Market	95 (475 %)	17.3 (93%)	27.4	-16.5	-38.1	5.9
Capacity Market	92 (460%)	19.4 (105%)	29.9	-16.6	-40.7	5.8

Source: KAPSARC analysis.

average cost of electricity (the consumer price if no rents were available for the utilities) includes electricity production and transportation costs.

In all scenarios, market restructuring delivers an increase in annual total surplus of more than $4 billion. However, much of that gain comes at the expense of consumers, with a significant increase in electricity prices. The very large price increase observed in the Cournot Energy Market scenario results from the strategic behavior of the Gencos, which restrict their production in order to maximize profits. This shows that, at least in theory, there is potentially significant room for price manipulation.

Allowing firms to exercise market power results in a slightly bigger total surplus because of the large increase in the firms' profits and the savings in fuel subsidies (due to a lower quantity of electricity generated). This result is specific to a country with significant subsidies for crude oil used in power generation.

In the Competitive Energy Market scenario, the saving in fuel subsidies exceeds the loss in consumer surplus. Therefore, the government can transfer fuel savings to low income consumers with a net surplus. This is not the case with the Cournot Energy Market scenario. Allowing for both the exercise of market power and reforming fuel prices result in an increase in the market value of SEC's existing assets, due to higher rents on production capacity. This justifies reforming fuel prices before restructuring the market in order to maximize government revenues from selling assets to the private sector.

Figure 1 shows that the capacity market improves reliability by providing more reserve margins nationally, which is not factored in the change in total surplus. In the Cournot Energy Market scenario, electricity purchased from neighboring regions during peak demand periods can remain cheaper than the survival and growth of local generators, leading to negative reserves in

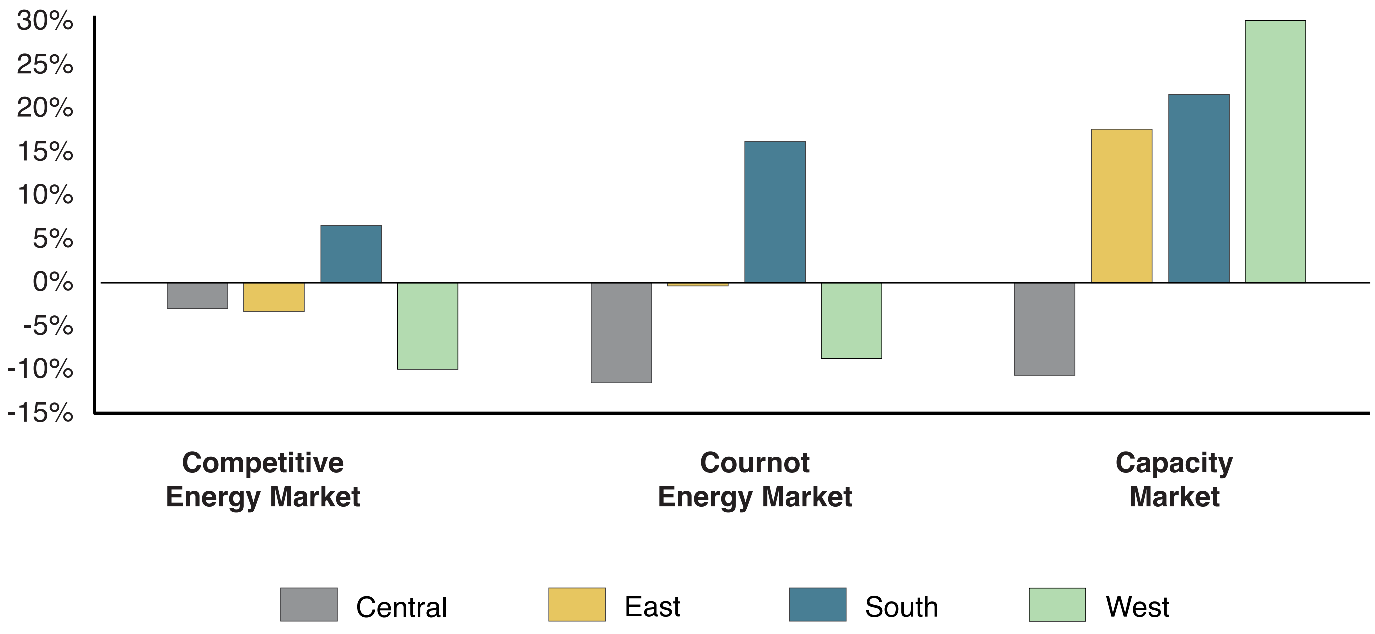

Figure 1. Reserve margin by operating area.

Source: KAPSARC analysis.

some regions. This phenomenon is much more attenuated in the Capacity Market scenario. We also show how adjusting the design of a regional Capacity Market influences the generators' decisions to invest and retire capacity. Therefore, the principal buyer can design the market to establish which technologies should survive in order to promote efficiency gains, improve reliability and to preserve existing government investments.

Introduction

Saudi Arabia plans to privatize and reform the power industry as part of its 2030 Vision and National Transformation Program (NTP). Two main issues face the Saudi Electricity and Co-Generation Regulatory Authority (ECRA) and the market operator, i.e., the principal buyer, which is a department of the Saudi Electricity Company (SEC); that is, achieving sufficient supply reliability and controlling the exercise of market power to protect the interest of consumers.

Restructured electricity markets both in the Americas and Europe have had to address the issue of market power and faced difficulties encouraging the required investment to meet reliability requirements. Regulators have been active in controlling the abuse of market power and compulsory divestments were used when firms were deemed too big to guarantee fair competition. The second issue, the lack of investment, seems harder to solve. For these reasons, the challenges faced by any country in the deregulation and liberalization of the electricity market are important.

A specific issue that has been the object of intensive debate is the role played by capacity markets in providing better signals for investment. One of the major problems with energy-only markets is that the operating and capital costs can be recovered only through the prices of electricity and ancillary services. Therefore, this market relies on the scarcity premium charged during the hours of very high demand to recover fixed costs (e.g., Battle and Pérez-Arriaga 2008; Joskow 2008; Finon and Pignon 2008; Roques 2008; ACER 2009; NERA 2011).

We construct a stochastic model for a typical zonal electricity market after adjusting for deregulation and liberalization with a functioning wholesale market for energy (in practice implemented as a bilateral market or pool auction), in which there is a clearing energy price at any given time. We also consider a capacity auction (or capacity payments) in which generators sell their capacity to serve peak demand, with different prices for capacity and energy at the zonal level. Using the model, we analyze how capacity market design impacts both the exercise of market power and the firms' optimal investments. In addition, we analyze how the configuration of the energy and capacity auction by the market operator may affect the generators' behavior and the exercise of market power over both auctions. The model is applied in a case study on the restructuring of the Saudi wholesale electricity market.

The model comprises a number of incumbent generators with market power (Cournot players) with a competitive fringe. Each generator's objective is to maximize profit. It also considers an independent transmission system operator (TSO) whose main task is to manage the electricity network and an implied market operator that organizes the energy and capacity markets. We also incorporate a representative arbitrageur that attempts to profit from possible price imbalances between different regions.

From a policy perspective the main innovation of this article is to address the following research questions: What is the impact of capacity prices on energy prices? Can generators use the energy market to exercise market power on the capacity market, or vice versa? How does the design of a capacity market influence the investment strategies followed by generators?

From a methodological perspective the major contribution is an analysis of the interactions between capacity and energy markets in a large model of competition, accounting for endogenous pricing, market power, locational issues for capacity auctions and transmission constraints, demand segmentation and investment in different technologies. This is achieved by solving the Nash Cournot equilibrium with oligopolistic generators, formulated as a mixed-complementarity problem (MCP).

The paper is structured as follows: In the next section we provide a review of literature on capacity markets, following which we introduce the market structure and profit functions represented in the model. We then explain how the market equilibrium is computed and summarize basic properties of the model. Thereafter, we apply the model to illustrate the potential effects of restructuring the Saudi electricity sector. Finally, we offer our findings and recommendations in the conclusion.

Electricity Market Design Literature Review

Hourly price spikes can cause extreme uncertainty and would be highly unpopular with society. Moreover, the short-run problem associated with the price spikes, which is also the main setback of energy-only markets, is the failure of the wholesale and ancillary services prices to rise high enough and yield the number of hours expected to produce efficient levels of investment in new capacity (Joskow 2008). This means that the need to recover the investment costs leads to electricity price spikes, and these would have to be even higher to justify the investment. The low probability of these price spikes occurring in a given year means firms have volatile returns. By imposing price caps regulators limit the returns, contributing to the shortage of capacity.

The failure of energy-only markets to deliver the level of capacity required to maintain security of supply has led to the introduction of different types of payments to reward capacity investments (e.g., Crampton and Stoft 2005; Gottstein and Schwartz 2010), including strategic reserves, capacity obligations, capacity payments, capacity auctions and reliability options (Finon and Pignon 2008; ACER 2009; Carreon-Rodrigues and Rosellon 2009; Traber 2017).

The capacity payments, instead of relying solely on the market to define the adequate level of investment, are based on a technical assessment of future electricity demand and the most efficient power-generation capacity required to meet this demand, providing investors with a more certain revenue stream (e.g., ACER 2009). This can increase wholesale prices, but provides greater reliability and lower price volatility. A recent study, applied to the U.S. Texas market (ERCOT), demonstrates how capacity payments provide greater benefit to consumers in the absence of market power (Bajo-Buenestado 2017).

These capacity payments have also been used in the U.K. and Spain, however, they have, in many cases, led to a level of investment that is larger than would be produced by a market driven industry, decreasing the scarcity rents (e.g., Roques 2008; NERA 2011). While these capacity payments were computed before delivery of electricity in Spain and after delivery in the UK, they have been subject to market manipulation in both cases. The Spanish market design was also flawed as it did not give incentives for the generators to be available in times of scarcity (e.g., Roques 2008).

On the other hand, in the capacity auction, each generator bids its capacity at a price it sees as adequate to compensate for the investment. The auction-based capacity markets usually take place several years ahead of actual delivery and compensate generation companies for investing in capacity, allowing them to cover at least part of the fixed costs associated with electricity generation. The main objectives of the capacity market are, as described in the U.K. Department of Energy and Climate Change (U.K. 2016a): to give incentives to build sufficient investment in capacity to meet the reliability standards; to achieve security of supply at minimal cost. Several studies have shown that, if implemented properly, capacity markets may achieve these objectives (e.g., Creti and Fabra 2007).

There are different ways of designing capacity markets. When there is an auction, the procurement agency can buy the expected required capacity (fixed and estimated by the agency) through an auction as in the Pennsylvania-New

Jersey-Maryland (PJM) Interconnection. Alternatively, the agency can design an explicit demand function for capacity for which an auction is also held, but with a buying price that is not only a function of the bids by the generators but also of the demand function provided by the buying agency. This is the case in the New England and U.K. capacity auctions, e.g., Statutory Instruments (2014).

In general these capacity markets have been shown to be flawed for several reasons: their lack of connection to energy markets, failure to incorporate new capacity, insufficient remuneration for investment in peaking capacity due to the short planning horizon, and failure to consider congestion charges and locational issues (e.g., Roques 2008; Crampton and Stoft 2005; Briggs and Kleit 2013). A survey of capacity markets in the U.S. (Bhagwat 2016) discusses how reliability goals were achieved, which, however, were at the expense of economic efficiency. As a deeper policy issue, Battle and Pérez-Arriaga (2008), Newberry (2016) and others have argued that capacity markets have been used to discretely introduce centralized planning. They also do not compensate for the risks of investing in the higher capital costs of baseload capacity.

Literature on the modeling of electricity oligopolies is extensive including the design of spot markets for energy pricing, investment in generation and asset trading (e.g., Bunn and Oliveira 2008, 2016; Murphy and Smeers 2012; Ehrenmann and Smeers 2010; Lorenczik, Malischek and Truby 2017), investment in and pricing of transmission (e.g., Yao, Oren and Adler 2007; Deng, Oren and Melipoulos 2010) and futures markets for electricity (e.g., Oliveira, Ruiz and Conejo 2013; Oliveira 2017).

The closest study to our analysis was done by Lynch and Devine (2017) in the analysis of capacity payments using a stochastic mixed complementarity problem in a stylized model. Our work extends and differs from theirs in several significant ways: we model capacity auctions as well as capacity payments; we include transmission with locational capacity markets (or payments), consider the activities of independent system operators and of arbitrageurs; we also analyze the properties of the model and how they are affected by different behavioral assumptions of the generators as well as decisions made by the market operator (principal buyer). To our knowledge, this is the first application of a numerical model to study the role of firm behavior and competition in the restructuring plan. Al-Muhawesh et al. (2008) provide a qualitative discussion with recommendations to improve the market.

Description of the Model with Both Energy and Capacity Markets

In this section we describe the model used to represent the interaction between the different agents in the market, including generators, a transmission system operator (TSO) and an arbitrageur. The model implicitly assumes that there is a market organizer responsible for the procurement of energy and capacity, which forecasts demand three years ahead of delivery. This procurement activity can take the form of organized auctions or bilateral trading.

The model takes into consideration the existing installed generation portfolio, which is allocated to different incumbent players or a competitive fringe. The generation and investment decisions are decentralized and controlled by profit-maximizing generators. To ensure the market clears without arbitrage opportunities, an independent agency operates the regional arbitrage of electricity. The indexes and variables used to describe the model are defined in Table 2.

Table 2. Sets and variables of the model.

	List of indices used in the model
h	Electricity generation technologies
i, j	Firms, including Gencos and competitive fringe
r	Regions in the zonal market
l, ll	Demand segments in the year
m	Subset of demand segments for which a capacity market is introduced
s	Scenarios capturing the stochastic component of demand and supply behaviors
	List of variables used in the model
π_i	Generator i's profit
S_{irls}	Energy sold by firm i in region r for demand segment l in scenario s
K_{ihr}	Available capacity with technology h owned by firm i in region r
P_{rls}	Energy market price in $/MWh in region r for demand segment l in scenario s
δ_{rm}	Capacity market price in $/MW for demand segment m in region r
$\rho_{rr'ls}$	Transmission price in $/MWh between regions r and r' for demand segment l in scenario s
	Primal Variables
Q_{ihrls}	Energy produced from technology h by firm i in region r for demand segment l in scenario s
I_{ihr}	Capacity built for technology h by firm i in region r
Y_{ihr}	Capacity retired for technology h by firm i in region r
$R_{irr'ls}$	Trade from region r to r' by firm i for demand segment l in scenario s
$A_{rr'ls}$	Arbitrage between regions r and r' for demand segment l in scenario s
$T^{+}_{rr'ls}$	Transmission services provided by the TSO from r to r'
$T^{-}_{rr'ls}$	Transmission services provided by the TSO from r' to r
	Dual Variables
η_{ihr}	Shadow price on the firms retirement constraint (3.4)
λ_{ihrls}	Shadow price on the firms capacity constraint (3.5)
$\rho^{+}_{rr'ls}$	Shadow price on the TSO's transmission constraint from r to r' (5.2)
$\rho^{-}_{rr'ls}$	Shadow price on the TSO's transmission constraint from r' to r (5.3)
$T_{rr'ls}$	Shadow price on the TSO's transmission constraint (5.4)

Source: KAPSARC.

The energy and capacity markets

The generators sell their production in the spot market. The TSO runs annual capacity auctions for the different demand segments in the different regions with the generators. ρ_{rls} is the energy price in \$/MWh in region *r*, for market segment *l*, and scenario *s*. δ_{rm} is the price set for capacity in \$/MW for market segment *m* in region *r*. We apply the following inverse demand functions (parameters described in Table 3):

$$P_{rls} = a_{rls} - b_{rls}\sum_{j} S_{jrls} + b_{rls}\left(\sum_{r'} A_{rr'ls} - \sum_{r'} A_{r'rls}\right) \quad \forall rls \qquad (1)$$

$$\delta_{rm} = \theta_{rm} - \xi_{rm}\sum_{j}\sum_{h} K_{jhr} \quad \forall rm \qquad (2)$$

Equation (1) defines the regional energy price in a given market segment and is set as a linear function of the total regional sales and the arbitrage activity. The demand response implicitly assumes that the wholesale price is passed to consumers. Equation (2) defines the regional capacity price for a given market segment as a function of the total capacity sold. It is assumed that all installed capacity is sold in the capacity market and that the capacity is always available to run when called upon. This representation enables us to capture both a capacity payment, when the slope is set to zero, and to analyze the outcome of a capacity auction with a negative slope.

The strategic generator's problem is summarized in (3), constructed using the coefficients in Table 4. We introduce the transmission price paid by the firm for trading electricity between regions as $\rho_{rr'ls}$. Although it is an exogenous parameter for the generators, in the integrated market it is derived using the marginal value of providing transmission services found in the later section titled: The TSO's Transmission Problem.

Table 3. Market Coefficients.

	Coefficients of the model
a_{rls}	Intercept of the inverse demand curve in (1)
b_{rls}	Slope of the inverse demand curve in (1)
θ_{rm}	Intercept of the capacity auction in (2)
ξ_{rm}	Slope of the capacity auction in (2)

Source: KAPSARC.

Table 4. Coefficients of the model.

	Coefficients of the model
c_{hrs}	Marginal cost of technology h in region r and scenario s in \$/kWh
D_l	Duration of segment l, in number of hours per year (same in all regions)
f_h	Retirement cost for technology h in \$/KW
o_h	Fixed operation costs for technology h in \$/KW
w_h	Investment cost for technology h in \$/KW
k_{ihr0}	Existing capacity in the system transferred to the Gencos (from SEC)

Source: KAPSARC.

Generator's problem: (3)

(3.1)

Max

$$\pi_i = \sum_r \sum_l \sum_s v_s \left(P_{rls} S_{irls} - \sum_h Q_{ihrls} c_{hrs} \right) D_{l_{\;rls}} - \sum_h \sum_r w_h I_{ihr} - \sum_h \sum_r o_h K_{ihr} - \sum_h \sum_r f_h Y_{ihr}$$
$$- \sum_{r'} \sum_{r'} \sum_l \sum_s v_s R_{irr'ls} \rho_{rr'ls} D_l + \sum_r \sum_l \delta_{rl} \sum_h K_{ihr} D_l$$

Subject to:

$$K_{ihr} = k_{ihr0} + I_{ihr} - Y_{ihr} \qquad \forall ihr \qquad (3.2)$$

$$S_{irls} = \sum_h Q_{ihrls} - \sum_{r'} R_{irr'ls} + \sum_{r'} R_{ir'rls} \qquad \forall irls \qquad (3.3)$$

$$Y_{ihr} \leq k_{ihr0} \qquad (\eta_{ihr}) \quad \forall ihr \qquad (3.4)$$

$$Q_{ihrls} \leq K_{ihr} \qquad (\lambda_{ihrls}) \; \forall ihrls \qquad (3.5)$$

$$Q_{ihrls} \geq 0,\; I_{ihr} \geq 0,\; Y_{ihr} \geq 0,\, R_{irr'ls} \geq 0$$

In the generator's profit function, equation (3.1), each scenario has an associated probability of v_s such that $\sum_s v_s = 1$, and the number of hours affected to each market segment is equal to the number of hours in the year, i.e., $\sum_l D_l = 8760$. The marginal values (duals variables) associated with the constraints appear in parentheses. We follow this convention throughout the paper.

The generator aims to maximize its expected profit defined by (3.1), which includes revenues from the sale of energy together with the expected revenue received in the capacity market, less the production, investment, retirement, fixed operation and transmission costs.

The identity (3.2) states how the level of installed capacity in each region, owned by firm *i*, depends on the level of capacity bought by the firms from existing assets in the system (SEC's existing assets), the level of new investment and the capacity associated with inefficient technologies that are retired. The retirements can be interpreted as SEC's stranded assets not purchased by the Gencos. Identity (3.3) relates sales with production and the trade implied by the generators' contracts and locations.

Constraint (3.4) defines the bounds for divestment: the maximum amount a company may close down is the initial capacity allocated to it from the current stock of available technologies per region. Constraint (3.5) defines the bounds of the production of electricity per region and per technology. The marginal values on these constrains are λ_{ibrls} in \$/MWh and η_{ihr} in \$/MW, respectively.

The arbitrageur's optimization problem

The role of the arbitrageur is to control rents extracted from interregional trade of energy by firms attempting to exercise their market power. The arbitrageur trades energy among zonal markets, guaranteeing that the differences between regional energy prices paid does not exceed the price of transmission, $\rho_{rr'ls}$. Otherwise, it would be possible for Gencos to increase profits by buying in the region with the cheaper price to sell in the more expensive region.

Let σ_{ls} be the profits from arbitrage in market segment *l* and scenario *s*, defined in the maximization problem, equation (4.1).

Arbitrageur's problem(s) (4)

$$\max \sigma_{ls} = \sum_r \sum_{r'} A_{rr'ls} \left(P_{r'ls} - P_{rls} \right) D_l - \sum_r \sum_{r'} A_{rr'ls} \rho_{rr'ls} D_l \qquad \forall ls$$

(4.1)

Subject to $A_{rr'ls} \geq 0$

The TSO's transmission problem

The TSO's transmission problem is represented in (5). The TSO's problem applies an aggregate representation of the transmission grid using zones connected by a radial network, which is the base to compute the zonal prices (e.g., Anderson, Philpott, and Xu 2007; Downward, Zakeri and Philpott 2010). This approximates the structure of a more detailed transmission network with nodes connected in loops. Since we assume a network without loops we do not use a linearized direct current (DC) load flow model to approximate Kirchhoff's current and voltage laws, as described by Gabriel et al. (2013).

TSO's problem(s): (5)

$$\min \mu_{ls} = \sum_{r} \sum_{r'>r} \left(T^{+}_{rr'ls} + T^{-}_{rr'ls} \right) D_l \varphi_{rr'} \quad (5.1)$$

Subject to

$$T^{+}_{rr'ls} > \sum_{i} \left(R_{irr'ls} - R_{ir'rls} \right) + A_{rr'ls} - A_{r'rls} \quad \left(\rho^{+}_{rr'ls} \right) \ \forall rr'ls, r < r' \quad (5.2)$$

$$T^{-}_{rr'ls} > \sum_{i} \left(R_{ir'rls} - R_{irr'ls} \right) + A_{r'rls} - A_{rr'ls} \quad \left(\rho^{-}_{rr'ls} \right) \ \forall rr'ls, r < r' \quad (5.3)$$

$$\chi_{rr'} \geq T^{+}_{rr'ls} + T^{-}_{rr'ls} \quad \left(\tau_{rr'ls} \right) \ \forall rr'ls, r < r' \quad (5.4)$$

$$T^{+}_{rr'ls} > 0, T^{-}_{rr'ls} > 0$$

Transmission services are decomposed into two variables, $T^{+}rr'ls$ and $T^{-}rr'ls$, operated along the existing capacity $\chi_{rr''}$. Since there is only ever a single direction for transmission it is only index for *r*< *r'*. $T^{+}rr'ls$ represents a positive flow from *r* to *r'*, while $T^{-}rr'ls$ represents flow in the opposite direction from *r'* to *r*. Note that as these are strictly non-negative, for a given connection between *r* and *r'* only one can take on a positive value. The objective function of the TSO (5.1) is to minimize the operating costs of transmission in each demand segment *l* and scenario *s*.

The identity (5.2) and (5.3) require that the total transmission greater than or equal to the balance between interregional trade and arbitrage. The dual variables of these constraints, $\rho^{+}_{rr'ls}$ and $\rho^{-}_{rr'ls}$, represent the marginal value, or the competitive price charged to the generators and arbitrageur for interregional trade.

Computing the Nash equilibrium

Here is a description of how we compute the Nash equilibrium for the electricity market game. Some properties of the model relevant to the operation of the capacity market and firm behavior are summarized thereafter.

When deriving the equilibrium problem, we define different behavioral assumptions representing how each firm expects its competitors will react to changes in the level of production and investments of their competitors. Let the partial derivative V_i represent the response, also referred to as the conjectural variation, of company *i* to the production of its competitors,

$$V_i = \sum_{j \neq i} \sum_{g} \frac{\partial Q_{jgrls}}{\partial Q_{ikrls}}$$

We use V_i to represent stylized firm behavior and as a measure of market power in a Nash-Cournot model; perfect competition (V_i=-1), Cournot players in an oligopoly (V_i=0) assuming other firms do not respond to their production. Given that the liberalized wholesale market, and real world data, does not yet exist for estimating the behavioral response of Saudi generators, we consider only these stylized cases. We also assume that the behavioral response for production and investments of a given firm are the same, using V_i for both in optimal conditions. In Appendix B Lemma 4, we show that the conjectural variations with respect to production and trade are the same.

The optimality conditions

The Lagrangian of the generators, the arbitrageur's and the TSO's problems are represented in Appendix A. Equations (6.1) to (6.4) come from imposing the condition that the gradient of the generators Lagrangians equal zero in the optimal solution, as it should be a stationary point, derived for the partial derivatives of Q_{ihrls}, I_{ihr}, Y_{ihr}, $R_{irr'ls}$ respectively. We convert the respective stationarity conditions (equalities) into complementarity conditions, the Karush-Kuhn-Tucker (KKT) conditions, by substituting in the non-negativity conditions on each decision variable.

(6)

$$P_{rls} - c_{hrs} - b_{rls}\left(1+V_i\right)S_{irls} - \lambda_{ihrls} \le 0 \qquad \perp \qquad Q_{ihrls} \ge 0$$

$$\forall ihrls \qquad (6.1)$$

$$\forall ihr \qquad (6.2)$$

$$\sum_m \left(\delta_{rm} - \xi_{rm}\left(1+Z_i\right)\sum_g K_{igr} \right) D_m + \sum_l \sum_s \lambda_{ihrls} v_s D_l \le w_h + o_h \qquad \perp \qquad I_{ihr} \ge 0$$

$$\forall ihr \qquad (6.3)$$

$$-\sum_m \left(\delta_{rm} - \xi_{rm}\left(1+Z_i\right)\sum_g K_{igr} \right) D_m - \sum_l \sum_s \lambda_{ihrls} v_s D_l - \eta_{ihr} \le f_h - o_h \qquad \perp \qquad Y_{ihr} \ge 0$$

$$\forall irr'ls \qquad (6.4)$$

$$\left(P_{r'ls} - P_{rls} - \rho_{rr'ls}\right) + \left(b_{rls}S_{irls}\left(1+V_i\right)\right) - \left(b_{r'ls}S_{ir'ls}\left(1+V_i\right)\right) \le 0 \qquad \perp \qquad R_{irr'ls} \ge 0$$

Equation (6.5) comes from imposing the condition that the gradient of the Arbitrageur's Lagrangian is equal to zero, with respect to $A_{rr'ls}$. This is the no-arbitrage condition for regional trade under imperfect competition.

$$P_{r'ls} - P_{rls} - \rho_{rr'ls} \ge 0 \qquad \perp \qquad A_{rr'ls} \ge 0$$

$$\forall irr'ls \qquad (6.4)$$

Equation (6.6) and (6.7) are the stationarity condition derived from the TSO's Lagrangian with respect to two transmission variables representing flows in opposite directions

$$\rho^{+}_{rr'ls} - D_l\varphi_{rr'} + \tau_{rr'ls} \ge 0 \qquad \perp \qquad T^{+}_{rr'ls} \ge 0$$

$$\forall rr'ls, r < r' \qquad (6.6)$$

$$\rho^{-}_{rr'ls} - D_l\varphi_{rr'} + \tau_{rr'ls} \ge 0 \qquad \perp \qquad T^{-}_{rr'ls} \ge 0$$

$$\forall rr'ls, r < r' \qquad (6.7)$$

We use the dual variables $\rho^{+}_{rr'ls}$ and $\rho^{-}_{rr'ls}$ to set the price paid for interregional trade and arbitrage, $\rho_{rr'ls}$, in \$/MWh, in identities (6.8) and (6.9), respectively.

$$\rho_{rr'ls} = \frac{\rho^{+}_{rr'ls}}{D_l} \qquad \forall rr'ls, r < r' \qquad (6.8)$$

$$\rho_{r'rls} = \frac{\rho^{-}_{rr'ls}}{D_l} \qquad \forall rr'ls, r < r' \qquad (6.9)$$

Finally, in order to calculate the Nash equilibrium that clears both the energy and capacity market we add the inverse demand functions, (1) and (2), the original identities and primal constraints from the generators problem, (3.2) to (3.5), and the TSO's problem (5.1) to (5.4).

Properties of the model

We now establish some basic properties of the model and provide analytical proofs in Appendix B that support the insights summarized here. Several intuitive results can be derived from the model:

i. The interdependence of energy and capacity markets.

ii. The impact of capacity markets on the market equilibrium, in the sense that capacity markets can increase production and decrease energy prices.

iii. The total investment in capacity decreases (increases) with the slope (intercept) of the energy and capacity demand functions.

Building on these basic properties we identify features in the design of the market that can influence both the behavior of participants and regional market structure. For instance, increasing firm investments and reserves (reliability) in regions where demand would otherwise be satisfied by regional arbitrage.

First we consider the case of firms supplying two different technologies in a simple market; a marginal technology with unconstrained capacity and a constrained baseload plant. Since the energy price is set by the marginal value of the peak plant, the baseload plant will benefit from higher rents in the energy market. For a firm operating both technologies, we use the expected value of the shadow price for the baseload capacity constraint (7.1) to derive an expression for the expected energy price (7.2) (see Theorem 1 in Appendix B). It is a function of the expected baseload operating costs, the total baseload fixed and investment cost divided by the number of hours in the energy market, market power terms from the capacity auction and energy market, and the capacity price in available market segments *m(l)*, times the ratio of total capacity market hours in the year. The last term is negative and shows how the capacity price acts to draw down the energy price proportional to the size of the capacity market. However, increasing the number of hours also increases the upward pull from the exercise of market power in the capacity auction.

$$\mathrm{E}\left(\bar{\lambda}_{ibrls}\right) = \frac{\left(w_b + o_b\right) - \left(w_p + o_p\right)}{\sum_{ll} D_{ll}} \; . \tag{7.1}$$

$$\mathrm{E}\left(P_{rls}\right) = \mathrm{E}\left(c_{brs}\right) + \frac{w_b + o_b}{\sum_l D_l} + \frac{\sum_m \left(\xi_{rm}\left(1 + Z_i\right)\sum_g K_{igr}\right) D_m}{\sum_l D_l} + \mathrm{E}\left(b_{rls}\left(1 + V_i\right) S_{irls}\right) - \delta_{rm(l)} \frac{\sum_m D_m}{\sum_l D_l} \tag{7.2}$$

These properties tell us that a firm operating both the marginal baseload and peakload plants, and exercising market power (V_i=0), can exploit the market by increasing both the energy and capacity price (in a capacity auction). The practical implication of this is that promoting competition among marginal producers, can help mitigate the exercise of market power by large baseload producers. In addition, the capacity market can help support smaller competing marginal producers by reducing the fixed costs of plants that are operating at a low utilization rate.

Another interesting insight reveals how the design of the regional capacity auctions influences local production, investment and retirement decisions. In Appendix B, we develop a proof (Theorem 3) for expression (7.3), defining the parameterization of the slope (ξ_{rm}) and intercept (θ_{rm}) of the capacity auction needed to increase investment by generators, beyond that of an energy-only market, when all available capacity is used.

$$\frac{\theta_{rm}}{\xi_{rm}} > \frac{\mathrm{E}\left(a_{rms} - c_{hrs}\right)}{\mathrm{E}\left(b_{rms}\right)} - \frac{w_h + o_h}{\mathrm{E}\left(b_{rms}\right)\sum_m D_m} \tag{7.3}$$

The analytical results also describe how the capacity auction design can determine which technologies are successful. For example, we derive the conditions (see Theorem 4 in Appendix B) under which at least one capacity market *m* prevents firm *i* from retiring technology *h*.

$$\sum_m \left(\delta_{rm} - \xi_{rm} \left(1 + V_i\right) \sum_g K_{igr} \right) D_m = o_h \tag{7.4}$$

$$\sum_l \sum_s \left(c_{hrs} - \left(P_{rls} - b_{rls} \left(1 + V_i\right) S_{irls} \right) \right) v_s D_l < f_h \tag{7.5}$$

$$\sum_l \sum_s \left(c_{hrs} - \left(P_{rls} - b_{rls} \left(1 + V_i\right) S_{irls} \right) \right) v_s D_l < f_h - o_h \tag{7.6}$$

Equation (7.4) ensures that the capacity market recovers the fixed maintenance cost (including market power effects). This is used to derive condition (7.5); the expected potential marginal operating losses, plus market power effects, are less than retirement costs, f_h. The equivalent condition for an energy-only market is presented in (7.6), with the retirement threshold reduced by the fixed operating costs, o_h. The main issue faced in designing the capacity market is then to decide which technologies should survive for reliability reasons, and to preserve existing government investments.

Restructuring the Saudi Electricity Industry: A Case Study

In this section we simulate the restructuring of the Saudi electricity market and unbundling of SEC into new private Gencos. The market is simulated for the year 2020 as a hypothetical start date for the wholesale market liberalization process. We calibrate the generators' problem as four independent regional generation firms (G1, G2, G3 and G4) owning the existing assets of SEC, including planned investments and retirements, in each of the four primary grid regions of Saudi Arabia; Central (COA), East (EOA), South (SOA) and Western (WOA). The regions are connected by existing transmission infrastructure as follows; COA-EOA (5.2 GW), COA-WOA (1.2 GW) and WOA-SOA (1.5 GW).

We treat the four large Gencos as Cournot players who exercise market power, with the fringe producers being price takers. Each firm can operate and invest in four different technologies: open cycle gas turbine (GT), combined cycle gas turbine (CCGT), steam turbine (ST) and GT to CCGT (GT to CC) conversion. The SEC's existing assets are distributed proportionately by technology and region among the four Gencos. The allocation used here does not represent any announced plans. It simply reflects a market with multiple players owning and operating a similar technology mix in each region.

Table 5 lists the investments, retirement, fixed-operation and non-fuel variable costs. Liquid fuel supplies are assumed to be unlimited in each region, whereas natural gas is allocated regionally based on the reported levels of gas consumption in 2015 and projected to 2020. The marginal cost of transmission is taken as $3.7/MWh.

Electricity demand is constructed using load profiles from 2015 (SEC 2016) projected to 2020 by rescaling the aggregate load profiles using regional demand forecasts from ECRA (2010). The demand segments are then aggregated into eight load segments for a representative weekday and weekend for the three seasons; summer, fall/spring and winter.

Table 5. Costs, expected lifetime and heat rate of technology.

Plant Type	Investment Cost $/kW	Retirement Cost $/kW	Lifetime Years	Fixed Cost $/kW	Variable Cost $/MWh	Heat Rate (MMBtu/MWh)	
						gas	oil
Gas Turbine (GT)	1,016	152	25	10.7	1.68	11.30	13.55
Combined Cycle GT (CCGT)	1,102	165	30	19.9	1.24	7.655	9.676
GT Conversion (GTtoCC)	600	-	20	19.9	1.24	7.655	9.676
Steam Turbine	1,680	252	35	38.7	1.22	10.37	10.20

Source: KAPSARC analysis.

Calibrating the coefficients of the inverse demand function, equation (1), requires estimates of the demand elasticity in the wholesale electricity market. Bigerna et al. (2015) developed a framework to estimate hourly demand elasticities and estimate own price elasticities between -0.05 and -0.12 in the Italian electricity market. Since the Saudi wholesale market has not yet been introduced, we use an average value of -0.16 based on estimates of the final demand elasticity of Saudi residential electricity consumers by Atallah et al. (2016). Future research is needed to refine our understanding on the potential for market power in Saudi Arabia's wholesale electricity market, particularly during peak demand periods.

Renewable production is taken as exogenous; 3.45 GW of installed capacity as forecast by the National Transformation Program 2020 (Yamada 2016). Hourly production profiles are estimated for each renewable resource and subtracted from the project demand. We use here previous work done with the KAPSARC Energy Model (KEM) for Saudi Arabia (Matar et al. 2015; Matar et al. 2017). The residual demand addressed to conventional generators is a stochastic parameter, which accounts for the unpredictability in both demand and from renewables.

Market structure and total surplus

We first analyze the impact of the ownership and distribution of SEC's assets when only an energy market is created (no capacity market).

Our business as usual (BAU) scenario represents the current market structure. The SEC controls production through existing and new power purchase agreements (PPAs) issued by the principal buyer to meet the targeted demand in 2020. In applying the PPA design with no wholesale market we assume no market power effects in the BAU. The firms continue to procure fuels at the same administered price of $1.25/MMBtu. The scenario matches how the government currently manages the market, prioritizing benefits to the consumer. However, providing energy at a low cost increases the financial risk faced by the government of balancing the budget for electricity supplies.

We analyze additional scenarios by introducing an energy-only market with SEC's existing generation plants distributed among four new Gencos, with SEC assuming the role of market operator (principal buyer). The competitive fringe, representing all other generators, is constrained to own and supply a maximum of 20 percent of the total capacity and energy, respectively, representing barriers to entry. These include limited access to capital for new firms, land rights or import permits for purchasing new equipment, in addition to incentives that favor the development of large Gencos.

We consider two contrasted scenarios in which the price of crude oil and natural gas procured by the firms is increased to an energy equivalent of $3/MMBtu, representing intermediate fuel price reform targets for the year 2020. The first scenario, the Cournot Energy Market, treats the four new Gencos as being able to exercise market power, forming a Cournot oligopoly ($V_i = 0$). In the second scenario, Competitive Energy Market, the Gencos operate in perfect competition, identical to the competitive fringe with $V_i = -1$.

We introduce a third scenario, Competitive Energy Market: Oil Price Reform, with oil fully deregulated to international prices, calibrated to $10/MMBtu, or $58/bbl.

Table 6. Profits, consumer surplus and total surplus (billion $).

Scenario	Firm Profits	Consumer Surplus	Fuel Subsidy	Total Surplus	Supply (TWh)	Average Price ($/MWh)	Average Cost ($/MWh)
BAU	0.89	118.27	-26.96	92.20	458	20.2	18.5
Competitive Energy Market	1.42	110.36	-15.26	96.53	434	38.1	35.1
Cournot Energy Market	28.30	80.20	-10.43	98.08	369	114.6	35.8
Competitive Energy Market: Oil Price Reform	16.02	83.95	0.00	99.98	346	106.6	60.6

Source: KAPSARC analysis.

The results of the BAU and the three energy market scenarios are summarized in Table 6, including firm profits, consumer surplus, fuel subsidies, total production and average electricity prices. In the BAU we report the average marginal production cost. The last column shows the average cost of electricity, or the consumer price assuming no rents for the utilities. Consumer surplus measures the value that consumers get for electricity beyond the price they pay. We compute fuel subsidies as the difference between the international market price and the administered price. Total surplus is defined as total generator profits plus consumer surplus less fuel subsidies.

In the scenarios with liberalized energy markets, consumer exposure to higher energy prices, compared with the baseline, drives the efficient use of electricity. This leads to a drop in supply, consumption of oil and fuel subsidies. These results are much more pronounced in the Cournot Energy Market, as the exercise of market power by the four Gencos reduces demand further and creates substantial rents on capacity.

The Oil Price Reform scenario demonstrates how the most efficient solution from a total surplus perspective involves eliminating all fuel subsidies and promoting competitive markets. A more counterintuitive result is that the total surplus increases when large Gencos exercise market power; the Cournot Energy Market is $1.6 billion more than the Competitive Energy Market. This is due to demand reduction that is closer to the deregulated scenario, lowering the economic losses from overconsumption and fuel subsidies. In addition, reducing competition and limiting the number of Gencos can increase the market value of SEC's existing assets for the government when selling them to the private sector.

However, compared with the BAU, both the Oil Price Reform and the Cournot Energy Market scenarios come at a significant cost to consumers. Average prices increase by more than 400 percent, while consumer surplus declines by $34.3 billion (26 percent) and $38.1 billion (32 percent), respectively. An increase of this magnitude would be highly disruptive and is unlikely to be accepted by the regulator. Unlike the Cournot Energy Market scenario, the decline in fuel subsidy expenditures at $11.7 billion exceeds the lost consumer surplus of $7.91 billion. Therefore, the government can transfer part of the fuel savings to low income consumers with a net surplus.

The case of perfect competition with partial fuel deregulation (Competitive Energy Market) results in more moderate price increases, with the deregulated prices (marginal cost) falling much closer to the consumer price. The decline in consumer surplus, significantly less than the scenarios with market power, is almost entirely driven by the fuel price reform.

Capacity payments and capacity auction

In this section we introduce additional scenarios by adding fixed payments and an auction for capacity to the Cournot Energy Market, demonstrating the impact of capacity markets on supply and prices when firms exercise market power. In the first Capacity Payment scenario each firm receives a fixed payment for its available capacity when the maximum demand in a region exceeds 90 percent of the total available capacity, and during summertime demand peaks between noon and midnight. The payment is set to the annualized fixed cost of a combined cycle gas turbine multiplied by the ratio of hours during the year when the capacity market is available.

In the second Capacity Auction scenario, we introduce an auction for capacity with the parameters of equation (2) set by the regulator. The auction is operated during the same demand segments defined for the Capacity Payment scenario. The intercept is set to double the annualized fixed cost *(FC)* of a combined cycle gas turbine evenly distributed across the hours in the year (FC), $\theta_{rm} = 2 \cdot FC$. The slope is defined such that the firms cover the fixed costs for a given capacity target in each region (C^*_r), $\xi_{rm} = FC / C^*_r$. In practice the firms recover only a portion of FC proportional to the total number of hours in the capacity market. The capacity targets are set to the existing capacity derived for the year 2020 (see Table 7). This allows enough flexibility for the capacity price to be substantially higher than the investment cost and, at the same time, incentivize the firms to offer enough capacity to meet the target at a lower capacity price.

Table 8 lists the total profits, consumer surplus, total surplus, supply and average unit price paid to the

Table 7. Existing capacity by technology in each region (GW).

COA	EOA	SOA	WOA	Total
18.99	29.48	7.42	27.64	83.53

Source: KAPSARC analysis.

Table 8. Profits, capacity payment, consumer and total surplus (billion $).

Scenario	Total Profits	Capacity Payment	Consumer Surplus	Total Surplus	Supply (TWh)	Average Energy Price ($/MWh)
Cournot Energy Market	28.30	0	80.20	98.08	369	114.6
Capacity Payment	31.00	-3.87	77.36	98.05	372	111.8
Capacity Auction	30.76	-3.52	77.59	97.98	371	112.1

Source: KAPSARC analysis.

firms (including capacity payments) for the energy-only market and the two capacity market scenarios. With the addition of capacity auctions (payments) we see increased profits and a reduction in the average energy price of up to 2.4 percent. However, the price drops are accompanied by a decline in both consumer and total surplus as the increase in capacity payments is larger than the savings the consumers receive in the energy price.

Figure 2 shows the available capacity, decomposed by technology for the five scenarios. First, increasing fuel prices shifts the firm's technology choice to more efficient CCGT units. In the Cournot Energy Market, many inefficient steam plants with higher fixed cost are retired as the regional oligopolies limit supplies. The Capacity Payment and Capacity Auction scenarios demonstrate how the actions by the principal buyer can influence the generators' optimal investment and retirement plans; the capacity market reduces retirements and increases investments.

Under the Capacity Payment and Auction scenarios, we see a slight increase in the baseload CCGT capacity, 2 GW and 1 GW, respectively. For the auction, we expect an increase in baseload supplies by satisfying equation (7.3) for one or more regions. However, since we have not differentiated the market by technology, the auction (payment) contributes to a significant reduction in the retirement of existing inefficient steam turbines. In Figure 2, the capacity of steam turbines increased from 19 GW (Cournot Energy Market) to 33 GW in both capacity market simulations. Segmenting the market by technology could be used to increase capacity without compromising the efficiency of the market, by preserving the signal to retire technology.

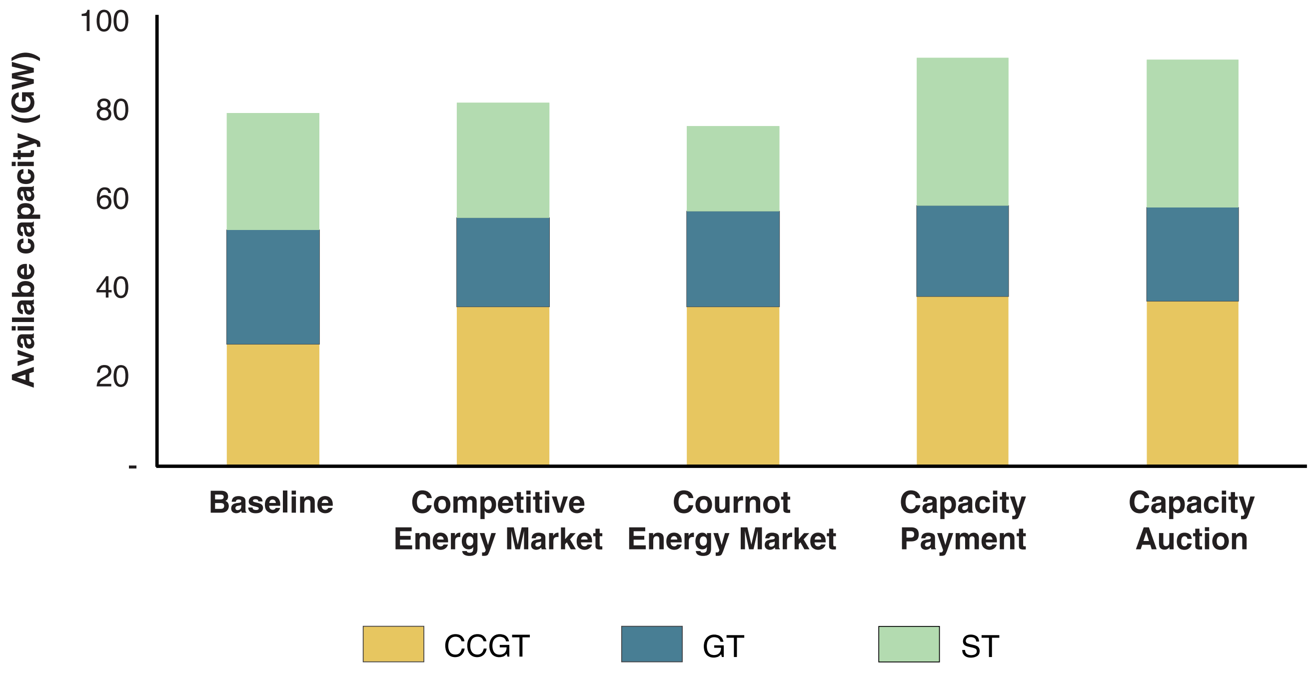

Figure 2. Available capacity (GW) per technology and market scenario.

Source: KAPSARC analysis.

Alternatively, the single capacity market design can help increase the value and survival of existing assets owned by the SEC.

By providing more capacity when capacity is fully utilized, the capacity market (payment) reduces price spikes and increases reserve margins used to maintain grid reliability. However, since the fixed capacity payment is paid by the consumer, their surplus declines (see Table 8). The fixed capacity payment plays an important role in the liberalized electricity market; increasing the reserve margins and supply reliability for consumers, measured as supplies in excess of the regional peak demand.

Under the Cournot Energy Market, while the national capacity is sufficient to meet demand, the regional reserve margins are negative everywhere except in the SOA (see Figure 3). This arises from the strong dependence on transmission between zones during peak demand periods. Gencos benefit from transmission services by leveraging the difference between regional load patterns and energy prices to increase their total capacity utilization and profits. However, in the Capacity Auction the reduction in fixed costs leads to lower retirements and stronger investments with margins exceeding 15 percent in the EOA, SOA and WOA, levels closer to the targets typically set by the SEC (ECRA 2016).

The COA is the only region with no significant increase in capacity. In this case the design of the auction (payment) is not sufficient to overcome the

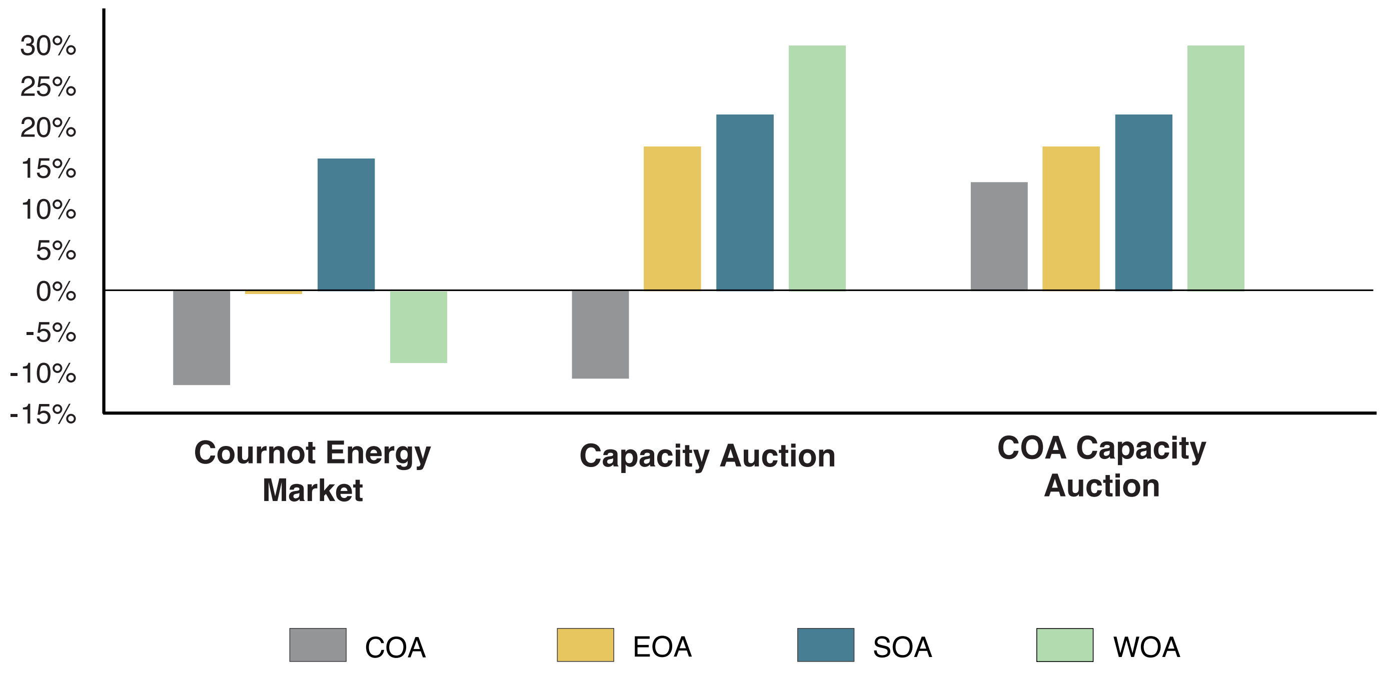

Figure 3. Reserve margins by operating area.

Source: KAPSARC analysis.

benefit of buying peak energy from excess capacity in the neighboring EOA and WOA. To address this, we simulate an alternate COA Capacity Auction scenario increasing the targeted capacity and the intercept of equation (2) in the COA by 50 percent. This increases the ratio θ_{rm}/ξ_{rm} in equation (7.3), reducing the firms signal to retire and increasing the incentive to invest. The reserve margins in the COA Capacity Auction scenario are compared with the Cournot Energy Market and the original capacity auction in Figure 3.

In Figure 4, we compare the equilibrium energy prices of the Competitive and Cournot Energy Markets, Capacity Payment and COA Capacity Auction scenarios for eight load blocks of the COA summer season. The Competitive Energy Market scenario demonstrates how managing market power is the primary factor in achieving low prices and controlling spikes. In the scenarios with market power, the capacity payments have the greatest impact on energy prices during the summer peak demand when the utilization of capacity is high. On average, the difference between the energy prices in the Cournot Energy Market and Capacity Payment scenarios is less than 0.13 percent in the winter and exceeds 2.4 percent in the peak summer season.

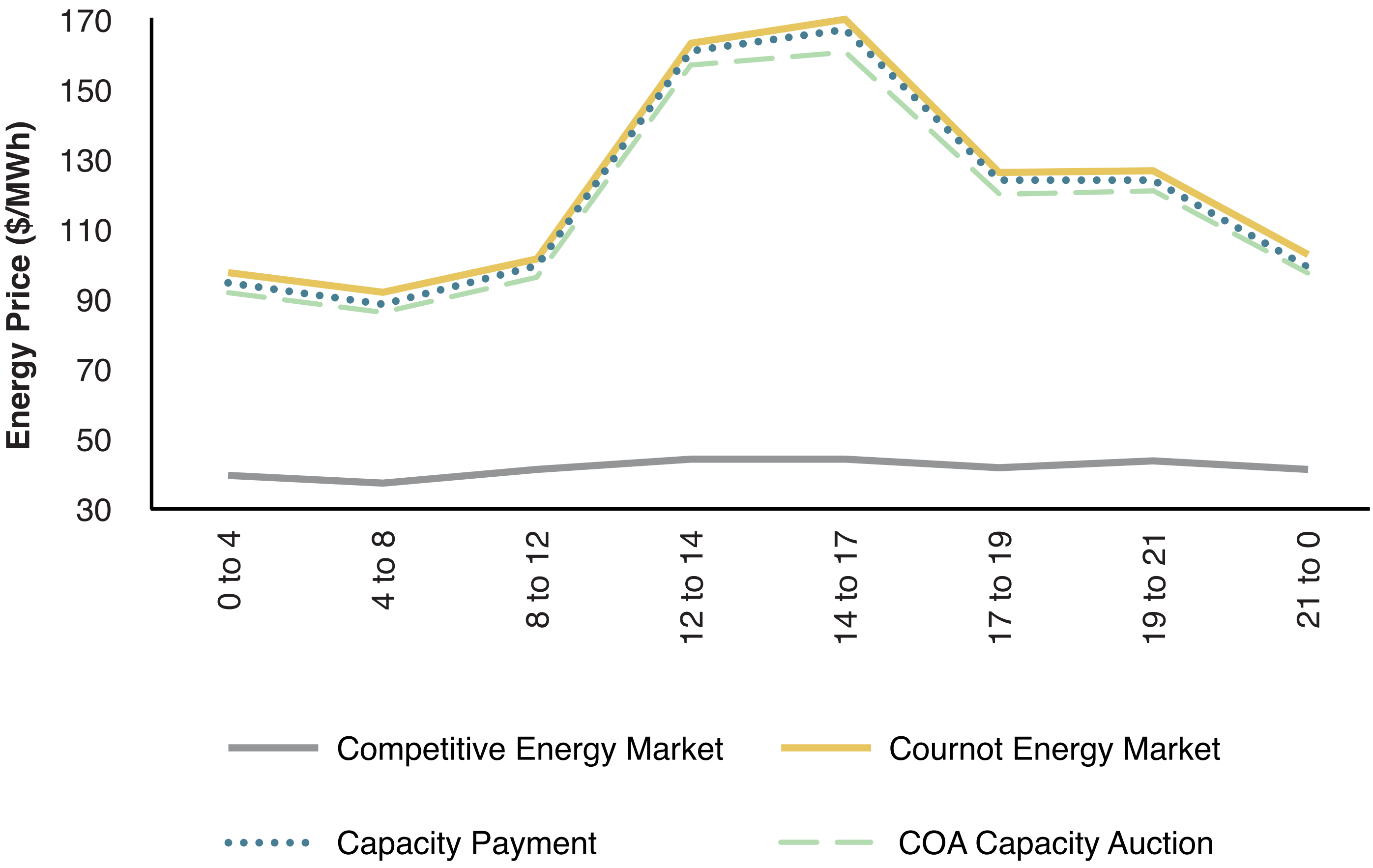

Figure 4. Energy prices in the COA summer weekend ($/MWh).

Source: KAPSARC analysis.

Finally, we analyze the sensitivity of energy and capacity prices to the regional capacity targets used in the adjusted COA Capacity Auction. Figure 5 compares the equilibrium prices in the COA by simultaneously modifying each of the regional targets by +/- 10 percent and 20 percent. Increasing the targets reduces the slope of the capacity auction. This limits the ability of firms to exercise market power over the rents on capacity in the energy market, leading to more supplies (higher capacity prices) and lower energy prices. The bars in Figure 5 demonstrate how regional targets set by the market regulator influence the reserves. Increasing the capacity target by 40 percent (far left to far right) raises the total systems cost by 3 percent, from $13.3 billion to $13.7 billion.

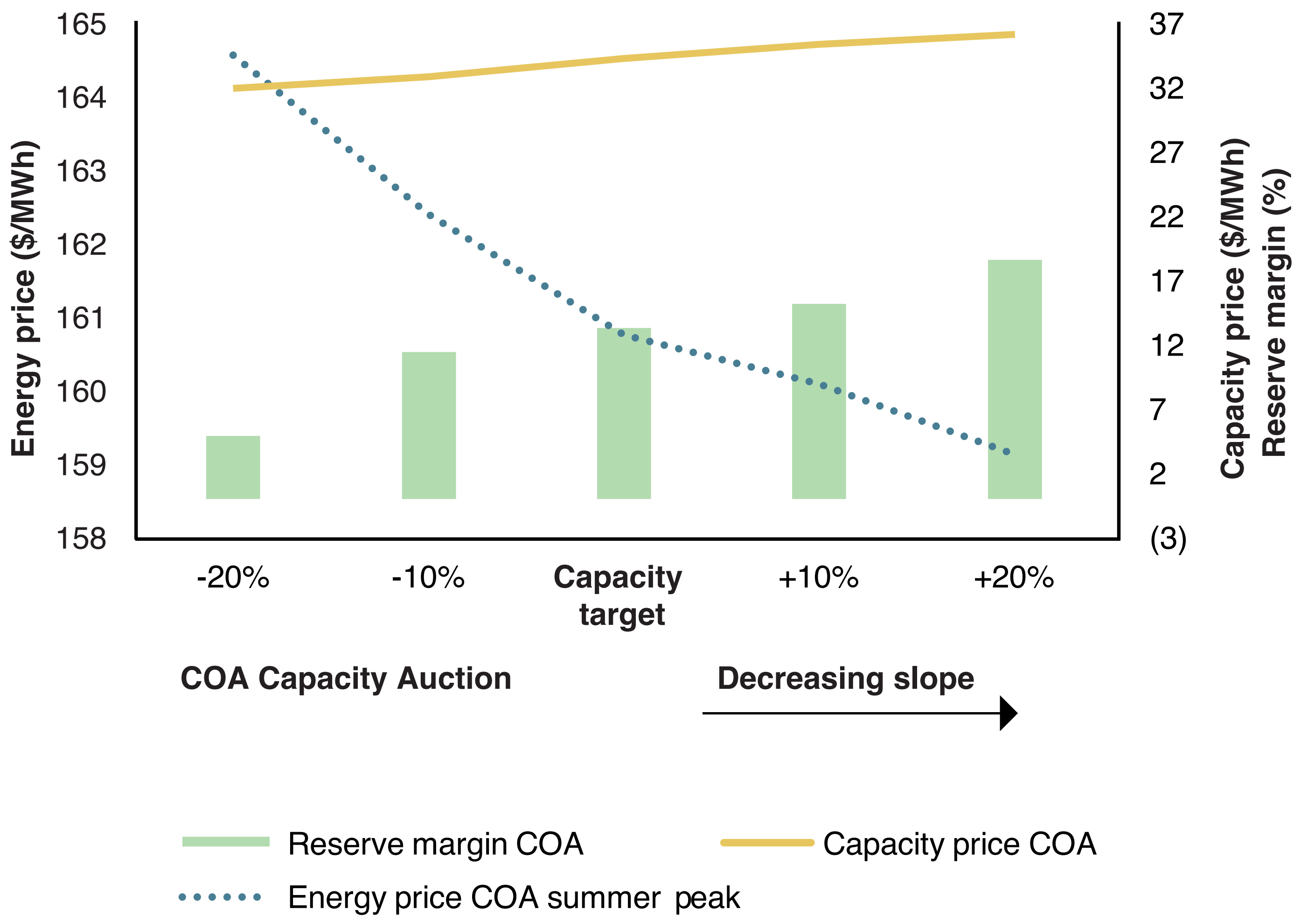

Figure 5. Capacity auction sensitivity analysis: results for the COA.

Source: KAPSARC analysis.

Conclusions

We built a large-scale model of the Saudi electricity system, with zonal pricing for transmission and both production and investment decisions for the generators. When power-generating firms can exercise market power, the model computes the Nash equilibrium of a Cournot oligopoly with a competitive fringe.

We find that the elimination of market power through competition or regulation is particularly relevant at peak demand times when competition is very limited and price spikes increase the profits of baseload producers. By reducing the fixed cost of plants, especially among small companies operating at low utilization rates, a capacity market promotes competition among peak generators and reduces electricity prices.

Our numerical simulations show how in Saudi Arabia, the exercise of market power with an energy-only market can potentially increase both firm profit and total surplus compared with a market where all firms behave competitively. This surprising result is mostly due to the size of the fuel subsidies (which do not exist in most electricity markets) outweighing the loss in consumer surplus.

Allowing for both the exercise of market power and reforming fuel prices results in an increase in the market value of SEC's existing assets due to higher rents on production capacity. This justifies reforming fuel prices before restructuring the market in order to maximize government revenues from selling the electricity assets to the private sector.

However, the gain to society comes at a significant cost to consumers as Gencos exercise market power over electricity prices. Given that competition will likely be limited during the early phases of implementation, regulation will be necessary in order to balance the value of the wholesale market with consumer welfare. In our Competitive Energy Market scenario with partial fuel price deregulation, the government's savings on crude oil (assuming a market value of $58/bbl) are more than enough to reimburse lost consumer surplus.

Finally, we derive the conditions under which the capacity and energy markets together lead to more capacity than the energy market on its own as well as a cap in peak prices. This supports the principal buyer in designing a market to achieve supply reliability during peak periods. We also show how the capacity market can be tailored to increase regional reserve margins and system reliability in regions affected by neighboring markets.

Learning from the experience of other countries and with careful market design, Saudi Arabia would benefit from restructuring its power sector in the long term. A capacity market would assist the market operator manage competition and influence private investment decisions in the liberalized market, thereby supporting the Vision 2030 objectives. Raising current administered fuel prices will improve the efficiency and costs of the Saudi generation mix. Meanwhile, reform to retail tariffs, charging consumers the efficient long-run cost of electricity and the inclusion of a wholesale energy market with congestion charges on transmission will contribute to improved consumption efficiency. Market reforms could also improve the internal efficiency within government-owned SEC. This, however, cannot be measured by the model presented here and requires using data envelopment analysis to compare SEC with industry benchmarks.

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Notes

Notes

Appendix A

The Lagrangian for the generators is represented as:

$$
\begin{aligned}
L_i = & \sum_r \sum_l \sum_s v_s \left(P_{rls} S_{irls} - \sum_h Q_{ihrls} c_{hrs} \right) D_l - \sum_h \sum_r w_h I_{ihr} - \sum_h \sum_r o_h K_{ihr} - \sum_h \sum_r f_h Y_{ihr} \\
& - \sum_{r'} \sum_r \sum_l \sum_s v_s \left(R_{irr'ls} \right) \rho_{rr'ls} D_l + \sum_r \sum_l \delta_{rl} \sum_h K_{ihr} D_l + \sum_r \sum_{r'} \sum_l \sum_s v_s R_{irr'ls} \zeta_{irr'ls} D_l \\
& + \sum_h \sum_r \alpha_{ihr} I_{ihr} + \sum_h \sum_r \underline{\eta}_{ihr} Y_{ihr} + \sum_h \sum_r \sum_l \sum_s \overline{\lambda}_{ihrls} \left(K_{ihr} - Q_{ihrls} \right) v_s D_l \\
& + \sum_h \sum_r \sum_l \sum_s \underline{\lambda}_{ihrls} Q_{ihrls} v_s D_l + \sum_h \sum_r \overline{\eta}_{ihr} \left(k_{ihr0} - Y_{ihr} \right).
\end{aligned}
$$

The dual variable associated with the non-negativity of arbitrage, $A_{rr'ls}$, is defined as $\gamma_{rr'ls}$. The Lagrangian for the arbitrageur's profit maximization problem is represented by:

$$
\begin{aligned}
\Lambda_{ls} = & \sum_r \sum_{r'} A_{rr'ls} \left(P_{r'ls} - P_{rls} \right) D_l - \sum_r \sum_{r'} \left(A_{rr'ls} \right) \rho_{rr'ls} D_l \\
& + \sum_r \sum_{r'} A_{rr'ls} \gamma_{rr'ls} D_l
\end{aligned}
\qquad \forall ls
$$

The dual variable associated with the non-negativity of transmission services, $T^{+}_{rr'ls}$ and $T^{-}_{rr'ls}$, are defined as $\varpi^{+}_{rr'ls}$ and $\varpi^{-}_{rr'ls}$, respectively. The Lagrangian for the ISO cost minimization problem is represented by:

$$
\begin{aligned}
\Omega_{ls} = & -\sum_r \sum_{r'>r} \left(T^{+}_{rr'ls} + T^{-}_{rr'ls} \right) D_l \varphi_{rr'} + \sum_r \sum_{r'>r} T^{+}_{rr'ls} \varpi^{+}_{rr'ls} + \sum_r \sum_{r'>r} T^{+}_{rr'ls} \varpi^{-}_{rr'ls} \\
& + \sum_r \sum_{r'>r} \left(T^{+}_{rr'ls} - \sum_i \left(R_{irr'ls} - R_{ir'rls} \right) - A_{rr'ls} + A_{r'rls} \right) \rho^{+}_{rr'ls} \\
& + \sum_r \sum_{r'>r} \left(T^{-}_{rr'ls} - \sum_i \left(R_{ir'rls} - R_{irr'ls} \right) - A_{r'rls} + A_{rr'ls} \right) \rho^{-}_{rr'ls}
\end{aligned}
\qquad \forall ls
$$

Appendix B

In Lemma 1 we show that in the absence of a capacity constraint the energy and capacity markets are not interdependent as they are only affected by the short-term marginal cost, and the ability of the marginal firm to exercise market power in the energy market. Moreover, in Lemma 1 we also prove that the marginal plant is able to set the capacity price high enough not only to recover the fixed costs but also to seek rents by using market power to increase the capacity price above social optimum.

Lemma 1: An unconstrained marginal plant *h* sets the energy price such that $P_{rls} = c_{hrs} + b_{rls}\left(1+V_i\right)S_{irls}$ and the capacity price is

$$\delta_{rm} = \frac{w_h + o_h}{\sum_m D_m} + \frac{\sum_m \left(\xi_{rm}\left(1+V_i\right)\sum_g K_{igr} \right) D_m}{\sum_m D_m}.$$

Proof: From equation (6.1) it follows that the market price is set by the unconstrained marginal plant such that $P_{rls} - c_{hrs} - b_{rls}\left(1+V_i\right)S_{irls} = 0$. Then, from (6.2), as $\bar{\lambda}_{ihrls} = 0$, it follows that $\sum_m \left(\delta_{rm} - \xi_{rm}\left(1+V_i\right)\sum_g K_{igr} \right) D_m = w_h + o_h$, as we only have one capacity market m in region *r*,

$$\delta_{rm} = \frac{w_h + o_h}{\sum_m D_m} + \frac{\sum_m \left(\xi_{rm}\left(1+V_i\right)\sum_g K_{igr} \right) D_m}{\sum_m D_m}. \blacksquare$$

In Lemma 2 we prove that the constrained baseload plant *b* is the price taker in the energy market, receiving a rent per MWh sold equal to the shadow price of capacity $P_{rls} - c_{hrs} - b_{rls}\left(1+V_i\right)S_{irls} = \lambda_{ihrls}$. The practical implication of this result is that the baseload plants benefit from a system in which the marginal plants are inefficient and have market power. Additionally, it follows from Lemma 2 that the capacity price does not need to cover the fixed costs as the baseload plants benefit from having higher rents in the energy market since the pricing is set by the marginal value of the peaking plant.

Lemma 2: A baseload plant *b* working with full capacity, receives a rent in the energy market equal to the capacity shadow price λ_{ibrls} and the capacity price is such that

$$\delta_{rm} = \frac{w_b + o_b}{\sum_m D_m} + \frac{\sum_m \left(\xi_{rm}\left(1+V_i\right)\sum_g K_{igr} \right) D_m}{\sum_m D_m} - \frac{\sum_l \sum_s \lambda_{ibrls} \nu_s D_l}{\sum_m D_m}.$$

Proof: From equation (6.1) it follows that the market price is set by the unconstrained marginal plant such that $\lambda_{ibrls} = P_{rls} - c_{brs} - b_{rls}\left(1+V_i\right)S_{irls}$ Then, from (6.2), and as $\lambda_{ihrls} = 0$, it follows that

$$\sum_m \left(\delta_{rm} - \xi_{rm}\left(1+V_i\right)\sum_g K_{igr} \right) D_m + \sum_l \sum_s \lambda_{ibrls} \nu_s D_l = w_b + o_b$$

which, given that δ_{rm} is unique, is equivalent to

$$\delta_{rm} = \frac{w_b + o_b}{\sum_m D_m} + \frac{\sum_m \left(\xi_{rm}\left(1+Z_i\right)\sum_g K_{igr} \right) D_m}{\sum_m D_m} - \frac{\sum_l \sum_s \lambda_{ibrls} \nu_s D_l}{\sum_m D_m}. \blacksquare$$

In Theorem 1, we analyze the relationship between the pricing strategies by a generator *i* owning, simultaneously, peak and baseload plants. In equilibrium, the expected shadow price of the baseload plant,

$$\mathrm{E}\left(\lambda_{ihrls}\right) = \frac{\sum_l \sum_s \lambda_{ibrls} \nu_s D_l}{\sum_l D_l}$$

is equal to the difference between the baseload and peak fixed costs per hour. This means that the capacity value depends on the difference between the fixed costs of baseload (higher) and peak plant, per hour. In part b) of Theorem 1, we see that firm *i* prices the energy as a function not only of the marginal costs and market power but also taking into account the difference between the baseload and peak fixed costs per hour.

Theorem 1: A generator *i* owning a baseload plant b and a peak plant p: a) sets the shadow price of baseload capacity constraint equal to

$$\mathrm{E}\left(\bar{\lambda}_{ibrls}\right)=\frac{\left(w_b+o_b\right)-\left(w_p+o_p\right)}{\sum_l D_l}.$$

b) sets the expected energy price in region r equal to

$\mathrm{E}\left(P_{rls}\right)=\frac{\left(w_b+o_b\right)-\left(w_p+o_p\right)}{\sum_l D_l}+\mathrm{E}\left(c_{brs}\right)+\mathrm{E}\left(b_{rls}\left(1+V_i\right)S_{irls}\right)$ and to c)

$$\mathrm{E}\left(P_{rls}\right)=\frac{w_b+o_b}{\sum_l D_l}+\frac{\sum_m\left(\xi_{rm}\left(1+Z_i\right)\sum_g K_{igr}\right)D_m}{\sum_l D_l}-\delta_{rm(l)}\frac{\sum_m D_m}{\sum_l D_l}+\mathrm{E}\left(c_{brs}\right)+\mathrm{E}\left(b_{rls}\left(1+V_i\right)S_{irls}\right).$$

Proof: From Lemma 1 we know that the marginal plant sets the capacity price such that

$$\delta_{rm}=\frac{w_p+o_p}{\sum_m D_m}+\frac{\sum_m\left(\xi_{rm}\left(1+Z_i\right)\sum_g K_{igr}\right)D_m}{\sum_m D_m}.$$

And from Lemma 2, for the baseload plant

$$\delta_{rm}=\frac{w_b+o_b}{\sum_m D_m}+\frac{\sum_m\left(\xi_{rm}\left(1+Z_i\right)\sum_g K_{igr}\right)D_m}{\sum_m D_m}-\frac{\sum_l\sum_s\bar{\lambda}_{ibrls}v_s D_l}{\sum_m D_m}.$$

a) Therefore, it follows that

$$\frac{w_p+o_p}{\sum_m D_m}+\frac{\sum_m\left(\xi_{rm}\left(1+Z_i\right)\sum_g K_{igr}\right)D_m}{\sum_m D_m}=\frac{w_b+o_b}{\sum_m D_m}+\frac{\sum_m\left(\xi_{rm}\left(1+Z_i\right)\sum_g K_{igr}\right)D_m}{\sum_m D_m}-\frac{\sum_l\sum_s\bar{\lambda}_{ibrls}v_s D_l}{\sum_m D_m},$$

from which we derive $\sum_l\sum_s\bar{\lambda}_{ibrls}v_s D_l=\left(w_b+o_b\right)-\left(w_p+o_p\right)$,

that is equal to $\frac{\sum_l\sum_s\bar{\lambda}_{ibrls}v_s D_l}{\sum_l D_l}=\frac{\left(w_b+o_b\right)-\left(w_p+o_p\right)}{\sum_l D_l}$, obtaining the expected shadow price for the baseload capacity constraint $\mathrm{E}\left(\bar{\lambda}_{ibrls}\right)=\frac{\left(w_b+o_b\right)-\left(w_p+o_p\right)}{\sum_l D_l}$.

b) If we now take the expected value of $\bar{\lambda}_{ibrls}=P_{rls}-c_{brs}-b_{rls}\left(1+V_i\right)S_{irls}$ and replace it in the previous identity we get

$$\mathrm{E}\left(P_{rls}\right)=\frac{\left(w_b+o_b\right)-\left(w_p+o_p\right)}{\sum_l D_l}+\mathrm{E}\left(c_{brs}\right)+\mathrm{E}\left(b_{rls}\left(1+V_i\right)S_{irls}\right).$$

c) Therefore, from Lemma 1 we can show that in a capacity auction the expected energy price is equivalent to

$$\mathrm{E}\left(P_{rls}\right)=\frac{w_b+o_b}{\sum_l D_l}+\frac{\sum_m\left(\xi_{rm}\left(1+Z_i\right)\sum_g K_{igr}\right)D_m}{\sum_l D_l}-\delta_{rm(l)}\frac{\sum_m D_m}{\sum_l D_l}+\mathrm{E}\left(c_{brs}\right)+\mathrm{E}\left(b_{rls}\left(1+V_i\right)S_{irls}\right).\ \blacksquare$$

To better understand the interaction between the capacity and energy markets we need to look at the demand segments in which there is a possibility of a severe market disruption, i.e., the marginal plant is generating at full capacity. In Theorem 2 we derive this relationship between the energy and capacity prices for an energy market in which the capacity market (or capacity payments) are paid to the generation available only in the segments where a disruption occurs. It is clear that the energy price depends on the capacity price and on the parameters used to design the capacity auction.

Theorem 2: Let us assume that region r is isolated from the rest of the system at a time m when demand is higher than installed capacity in r. The energy and capacity prices are such that

$$P_{rms} = a_{rms} - \frac{b_{rms}\theta_{rm}}{\xi_{rm}} + \frac{b_{rms}}{\xi_{rm}}\delta_{rm}.$$

Proof: From equation (6.14) we have $P_{rms} = a_{rms} - b_{rms}\sum_j S_{jrms}$ and from (6.15) we get $\delta_{rm} = \theta_{rm} - \xi_{rm}\sum_j\sum_h K_{jhr}$. As demand is higher than installed capacity, then $P_{rms} = a_{rms} - b_{rms}K_r$ and $\delta_{rm} = \theta_{rm} - \xi_{rm}K_r$, in which K_r represents the total installed capacity in region *r*. Then it follows that $K_r = \frac{\theta_{rm} - \xi_{rm}}{\delta_{rm}}$ and that $P_{rms} = a_{rms} - \frac{b_{rms}\theta_{rm}}{\xi_{rm}} + \frac{b_{rms}}{\xi_{rm}}\delta_{rm}$.

The capacity and energy prices are positively correlated in a capacity auction; in regions where capacity installed relative to demand is greater than other regions, the capacity price is lower and the energy price is also lower in case of a disruption (and vice versa in regions with lower installed capacity). Moreover, the higher the slope (ξ_{rm}) of the capacity demand the higher the energy price in case of disruption, and the higher the intercept (θ_{rm}) of the capacity demand the lower the energy price in case of disruption.

Next, in Lemma 3, we analyze the implications of a market disruption on the pricing strategy of a disrupted plant producing at full capacity, deriving the reaction function of *i* which represents how this firm responds to changes in the level of capacity of its competitors, given the energy and capacity market conditions.

Lemma 3: Let demand in segment m be higher than installed capacity in region r and for which there is a capacity auction (payment). For simplicity assume that $Z_i = V_i$, let $K_{ir} = \sum_g K_{igr}$ and K_{-ir} be the installed capacity, in region r, not own by i. The reaction function of firm i in planning how much capacity to own is represented by

$$\left[K_{-ir} + \left(2 + V_i\right)K_{ir}\right] = \frac{1}{\xi_{rm} + \mathrm{E}\left(b_{rms}\right)}\left[\theta_{rm} + \mathrm{E}\left(a_{rms} - c_{hrs}\right) - \frac{w_h + o_h}{\sum_m D_m}\right].$$

Proof: From equation (6.14), and given that the generators are producing at full capacity, we obtain $P_{rms} = a_{rms} - b_{rms}K_r$. And from equation (6.1) it follows that $\bar{\lambda}_{ihrms} = P_{rms} - c_{hrs} - b_{rms}\left(1+V_i\right)S_{irms}$, and as the generation is at full capacity $S_{irms} = K_{ir}$ and $\bar{\lambda}_{ihrms} = a_{rms} - b_{rms}K_r - c_{hrs} - b_{rms}\left(1+V_i\right)K_{ir}$. It then follows that by defining K_{-ir} to be the installed capacity in r not owned by *i* we get $\bar{\lambda}_{ihrms} = a_{rms} - b_{rms}\left(K_{-ir} + K_{ir}\right) - c_{hrs} - b_{rms}\left(1+V_i\right)K_{ir}$ and $\bar{\lambda}_{ihrms} = a_{rms} - c_{hrs} - b_{rms}K_{-ir} - b_{rms}\left[2+V_i\right]K_{ir}$. From (6.2), and as $\bar{\lambda}_{ihrms} > 0$, it follows that $\sum_m\left(\delta_{rm} - \xi_{rm}\left(1+Z_i\right)\sum_g K_{igr}\right)D_m + \sum_m\sum_s \bar{\lambda}_{ihrms}v_s D_m = w_h + o_h$.

Then, by replacing the shadow price into (6.2) we obtain

$$\sum_m\left(\delta_{rm} - \xi_{rm}\left(1+Z_i\right)\sum_g K_{igr}\right)D_m +$$

$$\sum_m\sum_s\left(a_{rms} - c_{hrs} - b_{rms}K_{-ir} - b_{rms}\left[2+V_i\right]K_{ir}\right)v_s D_m = w_h + o_h.$$

Moreover, as from (6.15) we get $\delta_{rm} = \theta_{rm} - \xi_{rm}\left(K_{-ir} + K_{ir}\right)$ and as $K_{ir} = \sum_g K_{igr}$, it follows that

$$\sum_m \left(\theta_{rm} - \xi_{rm}\left(K_{-ir} + K_{ir}\right) - \xi_{rm}\left(1+Z_i\right)K_{ir}\right)D_m +$$
$$+\sum_m \sum_s \left(a_{rms} - c_{hrs} - b_{rms}K_{-ir} - b_{rms}\left(2+V_i\right)K_{ir}\right)v_s D_m = w_h + o_h$$

which is equivalent to

$$\sum_m \left(\theta_{rm} - \xi_{rm}K_{-ir} - \xi_{rm}\left(2+Z_i\right)K_{ir}\right)D_m +$$
$$+\sum_m \sum_s \left(a_{rms} - c_{hrs} - b_{rms}K_{-ir} - b_{rms}\left(2+V_i\right)K_{ir}\right)v_s D_m = w_h + o_h$$

As $Z_i = V_i$, and as there is only one market for capacity *m* then θ_{rm} is the same for every *m*, and we obtain

$$\theta_{rm} - \xi_{rm}K_{-ir} - \xi_{rm}\left(2+V_i\right)K_{ir} + \mathrm{E}\left(a_{rms} - c_{hrs}\right) - \mathrm{E}\left(b_{rms}\right)K_{-ir} -$$
$$\mathrm{E}\left(b_{rms}\right)\left(2+V_i\right)K_{ir} = \frac{w_h + o_h}{\sum_m D_m},$$

which is equal to

$$\theta_{rm} + \mathrm{E}\left(a_{rms} - c_{hrs}\right) - \left[\xi_{rm} + \mathrm{E}\left(b_{rms}\right)\right]K_{-ir} - \left[\xi_{rm} + \mathrm{E}\left(b_{rms}\right)\right]$$
$$K_{-ir} - \left[\xi_{rm} + \mathrm{E}\left(b_{rms}\right)\right]\left(2+V_i\right)K_{ir} = \frac{w_h + o_h}{\sum_m D_m},$$

from which it follows that

$$\left[\xi_{rm} + \mathrm{E}\left(b_{rms}\right)\right]\left[K_{-ir} + \left(2+V_i\right)K_{ir}\right] = \theta_{rm} + \mathrm{E}\left(a_{rms} - c_{hrs}\right) - \frac{w_h + o_h}{\sum_m D_m}.$$

It then follows that the reaction function of player *i* can be represented as

$$\left[K_{-ir} + \left(2+V_i\right)K_{ir}\right] = \frac{1}{\xi_{rm} + \mathrm{E}\left(b_{rms}\right)}\left[\theta_{rm} + \mathrm{E}\left(a_{rms} - c_{hrs}\right) - \frac{w_h + o_h}{\sum_m D_m}\right]. \blacksquare$$

The main insight from Lemma 3 is that in situations where available capacity is constrained, the total investment in capacity decreases (increases) with the slope (intercept) of the energy and capacity demand functions; it also decreases with the marginal and fixed costs.

Still keeping to the possible scenario of an energy market in which the peak demand is subject to curtailments due to lack of capacity, we analyze, based on Lemma 3, when the capacity market (or a capacity payment) is able to lead to higher investment, when compared to the energy-only market option.

The results are summarized in Theorem 3: the capacity payment always leads to larger investment than the energy market only, however the capacity auction only increases investment under certain parameterization of equation (2) that sets the capacity price. Therefore, the principal buyer can design the capacity auction so that it meets the required criteria to be effective.

Theorem 3: If supply is not enough to meet peak demand in region *r* and segment *m*, when compared to the energy market only design: a) the capacity market increases investment if and only if

$$\frac{\theta_{rm}}{\xi_{rm}} > \frac{\mathrm{E}\left(a_{rms} - c_{hrs}\right) - \frac{w_h + o_h}{\sum_m D_m}}{\mathrm{E}\left(b_{rms}\right)};$$

b) a capacity payment $\theta_{rm} > 0$ increases the total investment.

Proof: From Lemma 3, if we have a capacity market

$$\left[K_{-ir} + \left(2+V_i\right)K_{ir}\right] = \frac{1}{\xi_{rm} + \mathrm{E}\left(b_{rms}\right)}\left[\theta_{rm} + \mathrm{E}\left(a_{rms} - c_{hrs}\right) - \frac{w_h + o_h}{\sum_m D_m}\right].$$

And in the absence of a capacity market $\xi_{rm} = 0$ and $\theta_{rm} = 0$ from which it follows that

$$\left[K_{-ir} + \left(2+V_i\right)K_{ir}\right] = \frac{1}{\mathrm{E}\left(b_{rms}\right)}\left[\mathrm{E}\left(a_{rms} - c_{hrs}\right) - \frac{w_h + o_h}{\sum_m D_m}\right].$$

a) The total capacity is larger by having a capacity market if and only if

$$\frac{1}{\xi_{rm}+\mathrm{E}(b_{rms})}\left[\theta_{rm}+\mathrm{E}(a_{rms}-c_{hrs})-\frac{w_h+o_h}{\sum_m D_m}\right]>$$
$$\frac{1}{\mathrm{E}(b_{rms})}\left[\mathrm{E}(a_{rms}-c_{hrs})-\frac{w_h+o_h}{\sum_m D_m}\right].$$

From which we derive

$$\frac{\theta_{rm}}{\xi_{rm}}>\frac{\mathrm{E}(a_{rms}-c_{hrs})-\frac{w_h+o_h}{\sum_m D_m}}{\mathrm{E}(b_{rms})}$$

b) Let $\theta_{rm}>0$ and $\xi_{rm}=0$ when you have a capacity payment. Then the capacity payment leads to more investment in capacity if and only if

$$\frac{1}{\mathrm{E}(b_{rms})}\left[\theta_{rm}+\mathrm{E}(a_{rms}-c_{hrs})-\frac{w_h+o_h}{\sum_m D_m}\right]>$$
$$\frac{1}{\mathrm{E}(b_{rms})}\left[\mathrm{E}(a_{rms}-c_{hrs})-\frac{w_h+o_h}{\sum_m D_m}\right].$$

which is true if and only if $\theta_{rm}>0$. ■

We have seen in Theorem 3 that the design of the capacity market is essential to produce incentives for having more investment. In Theorem 4 we prove that the capacity market design is also a determinant in selecting which technologies are successful, as the payment might ensure that a technology survives if the expected marginal short-run loss is less than the investment and retirement cost.

Theorem 4: If there is at least one capacity market *m*, in zone *r*, such that for a technology *hr*

$$\sum_m\left(\delta_{rm}-\xi_{rm}(1+Z_i)\sum_g K_{igr}\right)D_m=w_h+o_h$$

and

$$\sum_l\sum_s\left(P_{rls}-c_{hrs}-b_{rls}(1+V_i)S_{irls}\right)v_sD_l>-f_h-w_h$$

then firm i will never retire technology h in that region r.

Proof: As technologies only have revenue in states such that $\bar{\lambda}_{ihrms}$=0, (6.1) becomes $P_{rls}-c_{hrs}-b_{rls}(1+V_i)S_{irls}=\bar{\lambda}_{ihrls}$ and as we are considering divestment (6.3) is equal to

$$-\sum_m\left(\delta_{rm}-\xi_{rm}(1+Z_i)\sum_g K_{igr}\right)D_m-\sum_l\sum_s\bar{\lambda}_{ihrls}v_sD_l-\bar{\eta}_{ihr}=f_h-o_h\,.$$

From which it follows

$$\bar{\eta}_{ihr}=o_h-f_h-\sum_m\left(\delta_{rm}-\xi_{rm}(1+Z_i)\sum_g K_{igr}\right)D_m-$$
$$\sum_l\sum_s\left(P_{rls}-c_{hrs}-b_{rls}(1+V_i)S_{irls}\right)v_sD_l\,.$$

If the capacity market is set for plants to recover the investment and maintenance cost, then $\sum_m\left(\delta_{rm}-\xi_{rm}(1+Z_i)\sum_g K_{igr}\right)D_m=w_h+o_h$ and it follows that the maintenance cost is not important for the $\bar{\eta}_{ihr}=-f_h-w_h-\sum_l\sum_s\left(P_{rls}-c_{hrs}-b_{rls}(1+V_i)S_{irls}\right)v_sD_l$, which is a contradiction if and only if

$$\sum_l\sum_s\left(P_{rls}-c_{hrs}-b_{rls}(1+V_i)S_{irls}\right)v_sD_l>-f_h-w_h\,. \blacksquare$$

The main issue faced in designing the capacity market is then to decide which technologies need to survive for reliability reasons. We already know that the answer depends on the market. The main task is then to identify the technology whose survival increases consumer surplus.

Next, in Theorem 5 we prove that a) in the energy market the generator recovers the investment and fixed operation costs of a marginal plant only if it is able to exercise market power and that b) production and prices both increase and energy prices decrease when we have a capacity market.

Theorem 5: Let h be a marginal technology that only runs in market m and region r in scenario s, producing at full capacity. a) In an energy only market the generator recovers the investment and fixed if and only if $b_{rms}(1+V_i)S_{irms} \geq \frac{w_h + o_h}{v_s D_{ms}}$. b) The production increases and energy prices decrease with the capacity market.

Proof: Let *h* be producing at full capacity. Then from (6.1) and (6.2) we get

$$\left(P_{rms} - c_{hrs} - b_{rms}(1+V_i)S_{irms}\right)v_s = \frac{w_h + o_h}{D_m} - \left(\delta_{rm} - \xi_{rm}(1+Z_i)\sum_g K_{igr}\right).$$

a) In an energy-only market

$$P_{rms} - c_{hrs} = b_{rms}(1+V_i)S_{irms} + \frac{w_h + o_h}{v_s D_{ms}}.$$

b) It follows from

$$P_{rms} = c_{hrs} + b_{rms}(1+V_i)S_{irms} + \frac{w_h + o_h}{v_s D_{ms}} - \left(\delta_{rm} - \xi_{rm}(1+Z_i)\sum_g K_{igr}\right),$$

equation (1) and

$$\delta_{rm} - \xi_{rm}(1+Z_i)\sum_g K_{igr} \geq 0. \blacksquare$$

Lemma 4: a) The conjectural variations for sales and production are equal, i.e.,

$$V_i = \sum_{j \neq i}\sum_g \frac{\partial Q_{jgrls}}{\partial Q_{ikrls}} = \sum_{j \neq i} \frac{\partial S_{jrls}}{\partial S_{irls}}.$$

b) The conjectural variations on production and transmission are equal, i.e., $V_i = X_{irr'}$.

Proof: From the inverse demand function $P_{rls} = a_{rls} - b_{rls}\sum_j S_{jrls}$ we have

$$\frac{\partial P_{rls}}{\partial Q_{ikrls}} = -b_{rls}\left(1 + \sum_{j \neq i}\sum_g \frac{\partial Q_{jgrls}}{\partial Q_{ikrls}}\right)$$

and

$$\frac{\partial P_{rls}}{\partial S_{irls}} = -b_{rls}\left(1 + \sum_{j \neq i} \frac{\partial S_{jrls}}{\partial S_{irls}}\right)$$

from which it follows

$$V_i = \sum_{j \neq i}\sum_g \frac{\partial Q_{jgrls}}{\partial Q_{ikrls}} = \sum_{j \neq i} \frac{\partial S_{jrls}}{\partial S_{irls}}$$

Moreover, as

$$S_{irls} = \sum_h Q_{ihrls} - \sum_{r'} R_{irr'ls} + \sum_{r'} R_{ir'rls}$$

then

$$\frac{\partial P_{rls}}{\partial R_{irr'ls}} = b\left(1 + \sum_{j \neq i} \frac{\partial R_{jrr'ls}}{\partial R_{irr'ls}} - \sum_{j \neq i} \frac{\partial R_{jrr'ls}}{\partial R_{irr'ls}}\right).$$

Finally, as from definition, by transmitting electricity from one region to another we increase sales in the receiving region and decrease it in the producing region, we have

$$\frac{\partial P_{rls}}{\partial R_{irr'ls}} = -\frac{\partial P_{rls}}{\partial S_{irls}}$$

and

$$\frac{\partial P_{rls}}{\partial R_{ir'rls}} = \frac{\partial P_{rls}}{\partial S_{irls}},$$

and equivalently

$$\frac{\partial P_{rls}}{\partial R_{irr'ls}} = -\frac{\partial P_{rls}}{\partial R_{ir'rls}} = -\frac{\partial P_{rls}}{\partial S_{irls}}$$

and equivalently

$$\frac{\partial P_{rls}}{\partial R_{irr'ls}} = b_{rls}\left(1+V_i\right)$$

and

$$\frac{\partial P_{rls}}{\partial R_{ir'rls}} = -b_{rls}\left(1+V_i\right).$$

Then as

$$\frac{\partial P_{rls}}{\partial R_{irr'ls}} = b\left(1+\sum_{j\neq i}\frac{\partial R_{jrr'ls}}{\partial R_{irr'ls}} - \sum_{j\neq i}\frac{\partial R_{jrr'ls}}{\partial R_{irr'ls}}\right)$$

we obtain the relationship between the player conjectural variations on sales and transmission,

$$V_i = X_{irr'} = \sum_{j\neq i}\frac{\partial R_{jrr'ls}}{\partial R_{irr'ls}} - \sum_{j\neq i}\frac{\partial R_{jrr'ls}}{\partial R_{irr'ls}}\ . \blacksquare$$

About the Team

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About the Project

Saudi Arabia plans to reform and privatize its power generation sector as part of the Kingdom's Vision 2030. To provide analytical insights, we developed a model that simulates the restructuring of Saudi Arabia's electricity market, along with reforming fuel prices. We study the interactions between energy and capacity prices in a liberalized market. The project is part of KAPSARC's collaboration with the Principal Buyer department of the Saudi Electricity Company (SEC).

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