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Does Vertical Integration Always Reduce an Electricity Retailer's Fixed Price Offer?

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We use a profit-maximizing model of forward pricing, which revealed that an electricity retailer's fixed price offer (FPO) contains a large forward premium that encourages vertical integration of a generation company and a retailer. However, vertical integration does not always reduce FPOs, particularly when residential customers are segmented by consumption size and price sensitivity. Hence, a proposed merger of a big generation company and a big retailer requires regulatory scrutiny.

I. Introduction

Restructuring a region's electricity sector often leads to the creation of an independent system operator (ISO) of an electric grid, a competitive wholesale market for generation, a regulated market for transmission and distribution (T&D), and a competitive retail market for end-use consumption (Sioshansi, 2013). In the US, an electric grid's hourly wholesale market price is determined by an ISO's centralized market operation (Woo et al., 2019). Generation companies (Gencos) compete for sales to wholesale buyers, including local distribution companies and retail service providers (Woo et al., 2019).

A wholesale electricity market's hourly prices (\$/MWh) are highly volatile, with occasionally sharp spikes (Eydeland & Wolyniec, 2003). An important strand of the literature on retail pricing under volatile wholesale market prices is the pass-through of retail prices based on wholesale market price changes. The pass-through is partial, increases with wholesale price volatility, increases with rising retail competition, and declines with customer search costs (Brown, Tsai, et al., 2020; Deller et al., 2021; Fabra & Reguant, 2014; Hartley et al., 2019).

Partially driven by its forward-looking per MWh procurement cost (Brown, Tsai, et al., 2020), an electricity retailer's fixed price offer (FPO) depends on vertical integration that enables economies of coordination, scale, and scope (Arocena, 2008; Fetz & Filippini, 2010). A substantive research question thus arises: does vertical integration **always** reduce an electricity retailer's FPO? Underlying this question's real-world relevance and policy importance is the ubiquity of fixed price plans (Brown, Tsai, et al., 2020)

and mergers of large Gencos and retailers (Brown, Zarnikau, et al., 2020; Brown & Sappington, 2021).

The question's commonly received answer is "yes," because vertical integration tends to reduce a retailer's FPOs (Brown & Sappington, 2021; de Bragança & Daglish, 2017; Mydland, 2020). However, this answer may not hold when residential customers are segmented by consumption size and price sensitivity. As demonstrated below, our answer is based on the profit-maximizing pricing behaviour of a Gentailer (GT) affiliated with a Genco and a non-Gentailer (NGT) unaffiliated with a Genco.

II. A non-Gentailer's Optimal FPO

Consider a risk-neutral NGT's FPO of F_1 (\$/MWh) for a 12-month contract period. To meet its contractual obligation, a NGT procures Q_{1h} MWh in hour $h (= 1, \dots, H = 8,760)$ at day-ahead market (DAM) price P_h (\$/MWh). Mirroring the time sequence of retail market transactions, Q_{1h} is the *ex-post* MWh amount bought **after contract commencement** by a NGT customer. However, when making its FPO, a NGT does not know P_h and Q_{1h} and can only set F_1 based on its expectation of $\{P_h\}$ and $\{Q_{1h}\}$ subsequently realised in the FPO's contract period.

Suppose a NGT's average customer's *ex-post* linear demand is:

$$Q_{1h} = \alpha_h + \beta_1 F_1 + \omega_h, \quad (1)$$

where α_h is the time-dependent intercept, $\beta_1 < 0$ is Q_{1h} 's price response to a \$1/MWh change in F_1 , and ω_h is a random disturbance with zero mean and finite variance. The *ex-post* profit per customer in the contract period is:

$$\pi_1 = \sum_h (F_1 - P_h) Q_{1h}. \quad (2)$$

Let $E(Q_{1h}) = \mu_{Q1h}$, $E(P_h) = \mu_{Ph}$ and $\text{cov}(P_h, Q_{1h}) = \rho\sigma_{Ph}\sigma_{Q1h}$, where ρ = correlation of P_h and Q_{1h} , σ_{Ph} = standard deviation of P_h , and σ_{Q1h} = standard deviation of Q_{1h} . We expect $\rho > 0$ because of the weather's effects on P_h and Q_{1h} ; severe (mild) weather tends to cause high (low) P_h and Q_{1h} . As $E(P_h Q_{1h}) = E(P_h)E(Q_{1h}) + \text{cov}(P_h, Q_{1h}) = \mu_{Ph}\mu_{Q1h} + \rho\sigma_{Ph}\sigma_{Q1h}$ (Mood et al., 1974), a NGT's expected profit per **contracted** customer is:

$$\begin{aligned} E(\pi_1) &= \sum_h E[(F_1 - P_h)Q_{1h}] \\ &= \sum_h [(F_1 - \mu_{Ph})\mu_{Q1h} - \rho\sigma_{Ph}\sigma_{Q1h}], \end{aligned} \quad (3)$$

with $\partial\mu_{Q1h}/\partial F_1 = \beta_1 < 0$ based on equation (1), $\partial\mu_{Ph}/\partial F_1 = 0$ because μ_{Ph} is the expected value of the hourly DAM price determined by an ISO that assumes the hourly day-ahead aggregate demand is completely price insensitive (Woo, Moore, et al., 2016), and $\partial\sigma_{Q1h}/\partial F_1 = 0$ under the linear demand assumption.¹

We assume the probability of a customer contracting with a NGT is $J = J(F_1, M_1, F_2, M_2)$, where M_1 = marketing effort of a NGT; F_2 = FPO of a GT; and M_2 = marketing effort of a GT. We further assume J decreases with F_1 and M_2 but increases with M_1 and F_2 . This is because when a NGT lowers F_1 and raises M_1 , it increases the probability of customer signup. However, this probability declines when a GT reduces F_2 and raises M_2 . As the probability for a GT is $(1 - J)$, $J(\bullet)$ mirrors the market equilibrium of retailer choices made by residential customers.

The unconditional expected profit of a NGT **before contract signing** is:

$$\kappa_1 = JE(\pi_1) - C_1, \quad (4)$$

where C_1 is a NGT's marketing cost that increases with M_1 . The first order conditions for $F_1 > 0$ and $M_1 > 0$ that maximize κ_1 are:

$$\frac{\partial\kappa_1}{\partial M_1} = E(\pi_1) \frac{\partial J}{\partial M_1} - \frac{\partial C_1}{\partial M_1} = 0; \quad (5)$$

$$\frac{\partial\kappa_1}{\partial F_1} = J \frac{\partial E(\pi_1)}{\partial F_1} + E(\pi_1) \frac{\partial J}{\partial F_1} = 0. \quad (6)$$

Equation (5) states that at maximum κ_1 , $E(\pi_1) \partial J / \partial M_1$ = marginal benefit should equal $\partial C_1 / \partial M_1$ = marginal cost of a NGT's marketing effort. Hence, when a NGT has a high marginal marketing cost, it employs low marketing effort.

Using equation (3), we determine:

$$\begin{aligned} \frac{\partial E(\pi_1)}{\partial F_1} &= \sum_h \left[\mu_{Q1h} + (F_1 - \mu_{Ph}) \left(\frac{\partial\mu_{Q1h}}{\partial F_1} \right) \right] \\ &= \sum_h [\mu_{Q1h} + (F_1 - \mu_{Ph})\beta_1]. \end{aligned} \quad (7)$$

Equations (6) and (7) jointly inform a NGT's optimal FPO

$$F_1 = - \left(\frac{\mu_{Q1}}{\beta_1} \right) + \mu_P - \Delta_1, \quad (8)$$

where $\mu_{Q1} = \sum_h \mu_{Q1h} / H$ = average of a NGT's expected hourly sales per contracted customer; $\mu_P = \sum_h \mu_{Ph} / H$ = average of a NGT's expected hourly per MWh procurement costs; and $\Delta_1 = [E(\pi_1) / (JH\beta_1)] \partial J / \partial F_1$.

We expect $\Delta_1 \approx 0$ because $\partial J / \partial F_1 \approx 0$, as a \$1/MWh (= 0.1 cent per kWh) increase in F_1 is unlikely to cause NGT customers to switch and contract with GTs. Hence, equation (8) simplifies to:

$$F_1 = - \left(\frac{\mu_{Q1}}{\beta_1} \right) + \mu_P. \quad (9)$$

Equation (9) reveals a NGT's optimal F_1 price contains a forward premium of $(F_1 - \mu_P) = -(\mu_{Q1} / \beta_1) > 0$. This premium increases with average consumption size measured by μ_{Q1} but declines with *ex-post* demand's price sensitivity measured by β_1 .

To illustrate F_1 's calculation, suppose $\mu_{Q1} = 0.0014$ MWh², $\beta_1 = -0.0002$ ³, and $\mu_P = \$50/\text{MWh}$ ⁴. The resulting optimal F_1 is $[(0.0014 / 0.0002) + 50] = \$57/\text{MWh}$, closely matching the FPO data (net of T&D charges) available from Texas's Power to Choose website operated by the Texas Public Utilities Commission (Brown, Tsai, et al., 2020).

The forward premium embodied in F_1 is $[(57 - 50) = \$7/\text{MWh}]$, which is 14% of $\mu_P = \$50/\text{MWh}$. Should β_1 be -0.0003, the optimal F_1 would decline to $[(0.0014 / 0.0003) + 50] = \$54.7/\text{MWh}$. Hence, a NGT's optimal F_1 and forward premium decline when NGT customers consume less or become more price sensitive under smart metering (Jessee & Rapson, 2014).

III. A Gentailer's optimal FPO

Consider a risk-neutral GT affiliated with a Genco that uses natural gas as the marginal fuel (Woo, Moore, et al., 2016; Zarnikau et al., 2019, 2020). A GT's expected hourly per MWh procurement cost in the contract period is $E(X_h) = \mu_{Xh} < \mu_{Ph}$, where $X_h = \min(P_h, HR \times G_h)$, where HR = marginal heat rate (MMBtu per MWh) of natural-gas-fired generation and G_h = spot natural gas price (\$/MMBtu) in hour h (Woo, Horowitz, et al., 2016). This is because a GT would procure from the wholesale market if the hourly wholesale market price P_h is less than own-generation's hourly marginal fuel cost of $HR \times G_h$.

A GT's unconditional expected profit is:

$$\kappa_2 = (1 - J)E(\pi_2) - C_2, \quad (10)$$

1 After a small change in F_1 , the hourly demand's variance is $\text{var}(Q_{1h} + \beta_1 \Delta F_1)$. As $\beta_1 \Delta F_1$ is non-stochastic, $\text{var}(Q_{1h} + \beta_1 \Delta F_1) = \text{var}(Q_{1h})$. Hence, the change in F_1 does not affect $\text{var}(Q_{1h}) = \sigma_{Q1h}^2$.

2 The value of 0.0014 MWh = 1.4 kWh = (1,000 kWh ÷ 720 hours per month) matches monthly consumption of ~1,000 kWh per customer.

3 Implied by $\beta_1 = -0.0002$, $\epsilon = -0.0002 \times \$100 \text{ per MWh} \div 1 \text{ MWh} = -0.02$ is the own-price elasticity of monthly retail consumption at the total retail price of ~\$100/MWh which includes T&D charges. This implied ϵ matches the short-run elasticity estimates reported by Li et al. (2021).

4 Changing μ_P from \$50/MWh to \$55/MWh or \$45/MWh would alter the numerical results below. However, it would not qualitatively affect our answer to the policy question posted in Section I.

where π_2 is analogously defined as π_1 and C_2 is a GT's cost of marketing effort. Using the same steps for deriving equation (9), a GT's optimal FPO is:

$$F_2 = -\left(\frac{\mu_{Q2}}{\beta_2}\right) + \mu_X, \quad (11)$$

where $\mu_{Q2} = \Sigma_h \mu_{Q2h}/H$ = average of a GT's expected hourly sales per contracted customer; β_2 = price coefficient of a GT customer's ex-post linear demand, and $\mu_X = \Sigma_h \mu_{Xh}/H$ = average of a GT's expected hourly per MWh procurement costs.

To calculate F_2 , we assume $\mu_{Q2} = 0.0028$ MWh, $\beta_2 = -0.0001$ and $\mu_X = \$30/\text{MWh}$. Sharply different from those used to compute a NGT's F_1 , these assumptions are made to demonstrate the combined price effect of customer size, ex-post demand's price sensitivity, and per MWh procurement cost. The resulting F_2 is $\$[(0.0028 / 0.0001) + 30] = \$58/\text{MWh}$, embodying a forward premium of $\$28/\text{MWh}$, that is 93% of $\mu_X = \$30/\text{MWh}$. Despite the $\$20/\text{MWh}$ difference between μ_p and μ_X , F_2 is $\$1/\text{MWh}$ higher than $F_1 = \$57/\text{MWh}$, which is found in the last section. Further, F_2 's large forward premium encourages vertical integration observed in Europe and the US (Brown & Sappington, 2021).

IV. FPO Comparison and Market Segmentation

The FPO difference between a NGT and GT is

$$D = F_1 - F_2 = A + B, \quad (12)$$

where $A = (\mu_{Q2}/\beta_2) - (\mu_{Q1}/\beta_1)$ and $B = (\mu_p - \mu_X) > 0$. Affirming the commonly received answer in Section 1, equation (12) shows $D > 0$ if $A > 0$ or B exceeds $|A|$ when $A < 0$ ⁵.

Equation (12) also shows the necessary condition for $D < 0$ is

$$A = \left(\frac{\mu_{Q2}}{\beta_2}\right) - \left(\frac{\mu_{Q1}}{\beta_1}\right) < 0, \quad (13)$$

implying that a GT's optimal F_2 can exceed a NGT's optimal F_1 when GT customers consume more electricity and are less price sensitive than NGT customers. When $F_1 < F_2$, it indicates retail market segmentation, with relatively large customers preferring a GT and relatively small customers preferring a NGT.

A plausible explanation for retail market segmentation is that, when selecting a retailer, relatively large customers are more concerned with a retailer's reputation and financial strength than relatively small customers. Moreover, a NGT likely has a higher marginal marketing cost than a GT that enjoys economies of coordination, scale, and scope. Consequently, a NGT tends to rely more on price competitiveness than a GT to attract customer signups.

V. Conclusion

Our paper suggests that an electricity retailer's residential FPO contains a large forward premium that encourages vertical integration. However, a GT's FPO can exceed that of a NGT when GT customers have higher usage and are less price sensitive than NGT customers. Hence, a proposed merger of a big Genco and a big NGT requires close regulatory scrutiny to sustain the retail market's price competition.

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⁵ For example, if $\beta_2 = \beta_1 = -0.0002$, then F_2 will become $\$47$, lower than the F_1 obtained in Section 2.

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