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Designing a Competitive Electricity Market

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Years after the Electricity Power Industry Reform Act (EPIRA) marked the departure from a centrally-managed highly regulated structure to a decentralized market oriented system, the expected reduction in electricity prices and the investments boost in the sector have not taken place. This note tries to unravel the reform enigma by focusing on the design, specifically the introduction of competition at the wholesale level while limiting the analysis to trading protocols observed in the wholesale electricity spot market (WESM). Could electricity prices have been lower under a different market design from the one currently applied in WESM? Bidding behavior of market participants are largely influenced by auction design so that the observed behavior in one regime cannot be used to predict the outcomes in another. Thus no one auction design is superior and appropriate to all markets.

In early December 2013, MERALCO announced the largest single increase yet in generation cost in the Luzon grid since the industry was restructured.[2] Several consumer and political groups alleged that the price spike was due to regulatory capture and anti-competitive behavior of dominant suppliers. Those allegations stirred calls for reconsideration of the electricity reforms that began more than a decade ago, questioning the wisdom of the market-oriented path taken by the industry.

There is no doubt that the supply of electricity is still far below the benchmark of affordability, reliability and security envisioned by those who crafted and pushed for reforms. The Electric Power Industry Reform Act (EPIRA) was passed into law in 2001 after seven years of legislative tussle. That law facilitated the unbundling and introduction of competition in a state-owned, vertically integrated monopoly. It was expected that by moving away from a centrally-managed, highly regulated structure to a decentralized, market-oriented system, efficiency could be raised, prices to end-users reduced, and investments boosted. Contrary to the experience of other

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[2] Following the Malampaya shutdown and outages of several major generation plants, MERALCO's generation cost during November 2013 (billed in December) amounted to PhP 9.107/kWh, representing a 66 percent increase from the previous year's rate.

countries that had similar restructuring,[3] however, Philippine electricity prices did not fall but in fact rose, and investments in the sector remain lackluster.

Evidences of a flagging reform are copious. From 2004 to 2011, residential electric bills increased by 18 percent after adjusting for inflation and taxes.[4] Electricity rates in the Philippines are still among the highest in the region. Two recent surveys bear this out: a 2011 survey of 31 cities in Asia by the Japan External Trade Organization (JETRO) which showed the Philippines having the highest electricity rates in the cohort,[5] and a 2012 comparative study of 44 economies where the Philippines is ranked 9th but 2nd among Asian economies.[6] Indeed an average industrial producer in the Philippines spends 59 percent and 76 percent more in electricity than its counterparts in Thailand and Indonesia, respectively.[7]

Part of the explanation why electricity rates are obstinately high is the paucity of investments in generation despite growing demand and liberalization of entry into the generation business.[8] As prices rise due to tightening of supply, investments in new generation capacity should have been forthcoming if the policy environment is in shape. But extensive licensing requirements and bureaucratic red tape are dampening the appetite of investors. Thus from 2001 to 2013, only 652 megawatt (MW) (of which only 495 MW is dependable) was added to installed capacity in Luzon, while peak demand in the grid increased by 2,659 MW or more than four times as much.[9] The Philippine Energy Plan for 2012-2030 revealed that unless 600 MW of new capacity is on stream by 2016, the system will not meet the forecast demand and required reserves in the succeeding years. Considering that it took 12 years to inject nearly as much capacity in the system, there is little room for optimism that a looming power crisis can be averted.

The apparent unraveling of electricity market reform befits a review of its design and processes. This note focuses on the design, specifically the introduction of competition at the wholesale level.[10] The analysis is further limited to trading protocols observed in the wholesale electricity

[3] The restructuring of the electricity markets worldwide have inevitably taken different forms and shapes, not the least because of different initial conditions and policy objectives. Nonetheless, the basic characteristics of the restructuring are: (i) the replacement of regulation with market mechanisms in setting prices and allocating resources; (ii) open access to transmission and distribution networks; (iii) market determination of prices and resource utilization; and (iv) consumers' choice of supplier.
[4] This is based on a MERALCO residential customer with a monthly consumption of 200 kWh. In nominal terms, the electric bill of such customer nearly doubled, from PhP 5.70 per kWh in 2004 to
PhP 10.25 per kWh in 2011. After removing taxes and adjusting for inflation, the rates amounted to PhP 4.49 and PhP 5.31 per kWh, respectively. See CATIF (2013).
[5] JETRO (2011), "The 21st Comparative Survey of Investment-Related Costs in 31 Major Cities and Regions in Asia and Oceania," April.
[6] International Energy Consultants (2012), "Regional Comparison of Retail Electricity Tariffs: Executive Summary," June. The study used MERALCO prices to represent the Philippines.
[7] The rates have been computed for an industrial customer with 200-MWh monthly consumption. See CATIF (2013).
[8] Section 6 of EPIRA declared generation as a non-public utility, which means that it is not subject to the 40 percent cap on foreign investments and no legislative franchise is required for entry into the business.
[9] Manifestation of Manila Electric Company to the Supreme Court, 9 January 2014, p. 5.
[10] The electricity industry performs three primary functions: generation, transmission and distribution. Generation is the process of creating electricity. Transmission and distribution are "wires" or transport functions; the former refers to the process of conducting the flow of electricity at high voltages to groups of electricity users; the latter, to the process of transforming the high-voltage electricity to lower voltages and delivering it to end-users, i.e., households, industrial and commercial facilities, etc.
Wholesale refers to the sale of power by generator to distributors; retail pertains to transactions between consumers and distributors.

spot market (WESM). Despite a narrow focus, the inquiry is still relevant to the extent that generation cost accounts for more than half of prices paid by electricity users,[11] thus a better understanding of the wholesale market could help uncover a significant portion of the reform enigma. The discussion aims specifically to address concerns that electricity prices could have been lower under a different market design from the one currently applied in WESM. It clarifies that the bidding behavior of market participants are largely influenced by auction design, thus the observed behavior in one regime cannot be used to predict the outcomes in another. The lesson that emerges from this episode is a familiar but often neglected mantra: that no one auction design is *a priori* superior and apropos to all markets.

1 The WESM

Electricity market models are basically of two types: bilateral contracts and pool market. In the bilateral contracts market, participants are free to engage in any type of contractual obligations for the delivery of energy, which then becomes the basis for scheduling and dispatching of the generation units. The bilateral contracting structure is an extension of the pre-reform arrangement where most electricity transactions take place under specific supply contracts between two parties. The difference however is under the old regime, generators were limited to contracting only with a single buyer – the network owner *cum* operator. Pool markets, by contrast, represent a more radical departure from the old structure. A pool is a centralized exchange where all energy is sold and purchased, and all generation units are centrally scheduled and dispatched.

The Philippine electricity market is a hybrid of the pool and bilateral contracting models. Generators, distributors and suppliers may trade in the pool (WESM) but may also enter into bilateral, long-term supply contracts.

To achieve the present set-up, the Philippine electricity market went through restructuring in three phases. The first phase involved vertical restructuring, namely the unbundling of competitive (generation, supply and metering) from noncompetitive sectors (transmission and distribution), and assignment of network operations and transmission management and investments to independent organizations. This was followed by horizontal restructuring, when the state-owned utility, National Power Corporation (NPC), divested from electricity generation and opened the generation sector to private investments. Key to restructuring horizontally, i.e., to allow competition in generation, was the establishment of the WESM, which serves as a platform for competitive trading of energy and capacity between power producers (generators) and suppliers (distributors and retail marketers). The industry has just entered into the third phase, retail competition. This allows contestable consumers (those requiring at least 1 MW) to purchase electricity from one or several

[11] The retail electricity price for a 200-kWh consumption by residential customer is comprised by the following: generation c ost, 51.4%; transmission, 10.2%; distribution, 20.8%; taxes, 9.2%; others (system loss, temporary adjustment, universal charges and subsidy), 8.3%.

suppliers or directly from generators, even as electricity is still physically delivered to them by local distributors. More important, retail competition breaks up the distributor's monopoly franchise for selling electricity to customers, permitting consumers to have a choice of suppliers.

Figure 1.
Structure of the Philippine Electricity Market

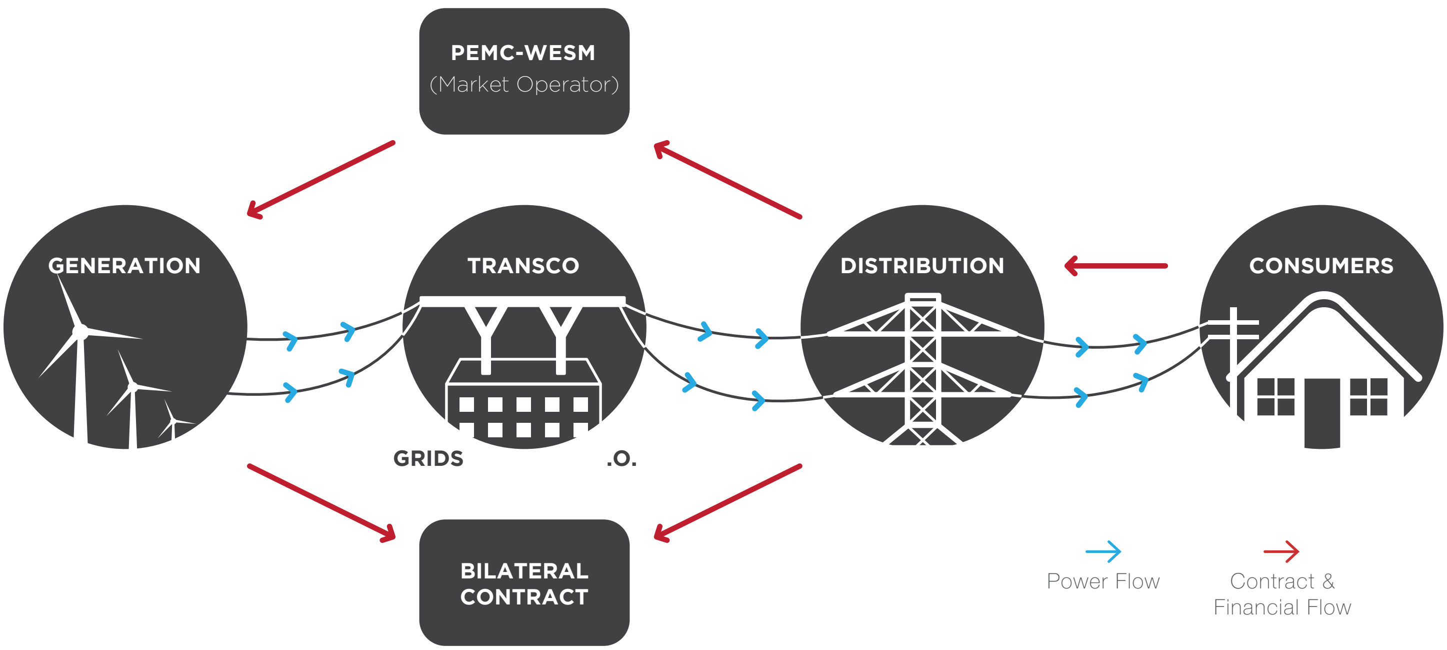


Figure 1 describes the current market structure. WESM operates alongside a bilateral contracting market.[12] The management of transmission grid and system operation are delegated to a private group, the National Grid Corporation of the Philippines (NGCP), although NPC retains ownership of the grid.[13] The pool market or WESM is currently the responsibility of the Philippine Electricity Market Corporation (PEMC), which administers the market on a non-profit basis in accordance with the rules formulated and subscribed to by participants and approved by the Energy Regulatory Commission (ERC). PEMC was organized by the Department of Energy (DOE) as provided for in EPIRA.[14] Its current operation is financed by fees of market participants.

[12] The distribution utilities were required to source at least 10 percent of their total demand from WESM during the first five years of WESM's commercial operations that started in July 2006.
[13] In other jurisdictions, the function of grid management is delegated to an entity distinct from system operator.
[14] EPIRA envisions however that the operations of WESM will be transferred to an autonomous group, one year after the start of WESM's commercial operations. Such transfer has yet to happen, more than seven years now in WESM operations.

Four basic principles characterize WESM operations. First, it is a real-time market, where electricity price is determined every hour by generators' offers to sell and centralized demand forecast. Generators can stipulate any price at which they are willing to supply. There is provision to accept demand bids from distributors, marketers, retail suppliers and customers but like most power pools, only the supply-side of the auction is presently functioning. Thus during trading, demand is deemed fixed, i.e., inelastic or unresponsive to prices. Being a suppliers' market, the concern is whether generators are exercising market power, individually or in concert, by withholding capacity to create artificial supply shortage in order to raise price.[15]

WESM runs on a gross pool concept: all energy transactions are scheduled through the market. All electricity to be delivered in the grid, whether or not covered by bilateral contract, must be offered in the spot market to ensure economic (least cost) dispatch. The spot price at any given hour balances the supply of and demand for electricity. But such price is applied only to traded quantities that are not subject of bilateral contracts. Thus even if the quantities covered by bilateral contracts are included in setting the spot price, they are nonetheless settled at prices agreed upon by contracting parties. Other markets, mostly in Europe, operate on a net pool concept where trading in the spot market is limited to quantities not covered by bilateral contracts.

A third feature is uniform pricing. At any given trading interval, there is one system marginal price (SMP) that clears total supply (offers by generators) and forecast demand.[16] An alternative market design allows for discriminatory or "pay-as-bid" pricing. However, even under uniform pricing, prices differ by location in the grid on account of transmission loss and congestion.[17] The Luzon grid, for instance, is divided into 390 nodes, and therefore has as many nodal prices.

Finally, WESM is a self-governing body.[18] This is consistent with EPIRA's declaration of the generation sector as competitive and therefore outside the purview of traditional regulation. The ERC, nonetheless, exercises oversight over WESM through approval of market rules and fees, and market operator's (PEMC) budget. The regulator also maintains the right to intervene in cases involving anti-competitive behavior of participants.

[15] Even in pools with two-way bidding, i.e., where both demand bids and supply offers are accepted, the concern is still with suppliers' market power since there are very few loads that can reduce their consumption strategically in order to raise prices.

[16] Under competitive conditions, SMP represents the industry's marginal cost, which is operationally represented by average variable cost or the operating cost of the last generator dispatched to meet energy demand.

[17] The locational marginal price (LMP) that is applied to the electricity generated by a plant in a given node is the sum of SMP and costs of line losses and transmission congestion in that node.

[18] Governance in WESM is exercised through a 15-man board, comprised by one representative each from PEMC, NGCP, suppliers; four representatives from generation; four representatives from distribution utilities and electric cooperatives; and four independents nominated by WESM members. The DOE Secretary acts as "interim" chair. Moreover, there are five independent governance committees, namely, Market Surveillance, Audit, Rules Change, Technical, and Dispute Resolution, whose members are appointed by DOE. Of these committees, the Market Surveillance Committee (MSC) is responsible for monitoring breaches of market rules.

2 Price Determination in WESM

Since the generation component represents more than half of the retail electricity price, the determination of prices in WESM is at the core of the puzzle why electricity prices are rising despite market reforms. Like any auction market, trading rules are crucial as they define opportunities for strategic behavior that could distort market outcomes.

Except for a few nuances, WESM trading rules are an adaptation of those observed in many US electricity markets[19]. All generation plants are required to submit price and quantity offers every trading hour. A generator's offer, which can consist of up to 10 blocks of price-quantity pair with monotonically increasing prices, may be submitted as early as seven days and no later than two hours before the trading hour.[20] If at any trading hour, a plant fails to submit an offer, the market operator uses the plant's default offer that is submitted upon its registration to WESM.

There is no lower limit on the price that may be offered, i.e., negative price offers are acceptable.[21] An upper cap is set at PhP 62.00/kWh, however. The market operator publishes day-ahead and week-ahead forecast of load demand to guide the offers of sellers.

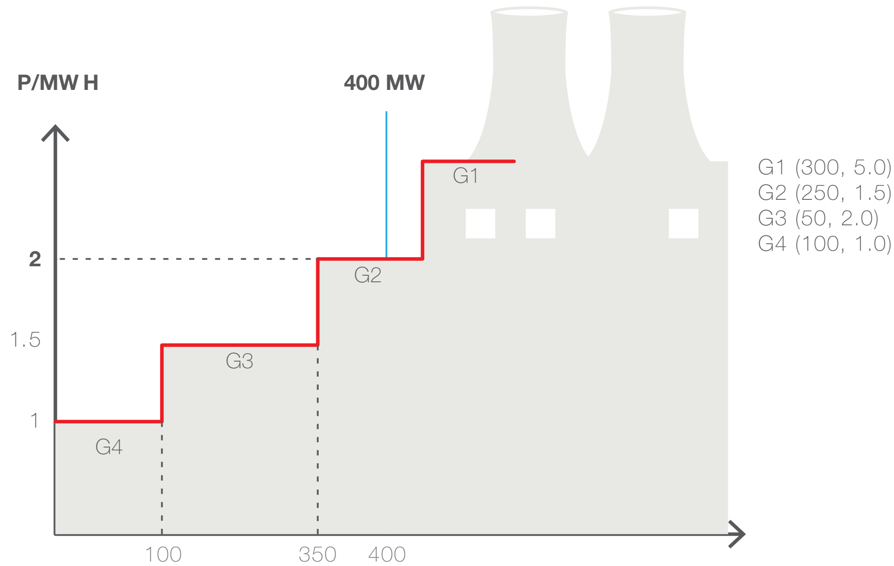
From the offers submitted by generators, a merit order is compiled. Offers are stacked in ascending price order.[22] A clearing (equilibrium) price, labeled as SMP, is based on the price of the last block needed for the cumulative quantity in the merit order to meet the forecast demand. Those offers with price not higher than SMP are accepted, and the corresponding quantities are scheduled for dispatch. All plants that are dispatched in the grid receive the same price, i.e., the SMP. But their actual revenues could vary because of values attributed to line losses and transmission congestion specific to the location of a plant. How these protocols determine price in the market is illustrated in Figure 2.

Suppose there are four generation plants (labelled G1 to G4), with quantity-price offers as follow: (350, 5), (250, 1.5), (60, 2), and (100, 1). The electricity demand or load at a particular trading hour is forecast at 400 MW; accordingly an equal amount of capacity is needed. Based on merit order, G4 and G2 receive priority dispatch since their prices are lower than the offers made by other generators. Moreover, 50 of 60 MW offered by G3 is needed to close the demand-supply gap, and therefore dispatched. As evident, the market clears at PhP 2.00/kWh.

In practice, generation plants offer their capacities strategically in several blocks, rather than in singles. In most power pools, the specified quantity in the first offer block is the plant's minimum operating load, i.e., the least capacity that it ought to run to be stable. But in WESM, the quantity in the first offer block comes after the plant's minimum operating load, (referred to as "Pmin" rule

[19] These include the markets of California, Pennsylvania, New Jersey and Massachusetts.
[20] The blocks should have non-decreasing prices, i.e., the price in the second block must not be less than the price in the first, and so on.
[21] Offers can go as low as negative infinity technically, but a finite quantity is necessary for optimization. Thus, the lower limit is arbitrarily set to negative PhP 99, 9999/MWh (previously, negative PhP 2,500/MWh).
[22] If demand bids were accepted, they would be ranked in descending price order.

Figure 2.
Price Determination in the Wholesale Electricity Market



or shorthand for minimum stable load). Because of the so- called "Pmin rule", all generation plants that submitted their offers should be able to run at their respective Pmin levels even if none of the blocks that they offered are accepted. Pmin quantities are registered by the generators with the market operator and presumed to be based on the technical requirements of the plants. Generators receive the market clearing price for their Pmin quantities. Such a rule is designed to ensure that at any time, there would be some fixed capacity available, equal to the total Pmin of all generation plants that submitted offers. In addition, exempting Pmin from competitive bidding reduces the size of contestable demand, which should push generators to bid more aggressively.

Yet even as the minimum stable load of a plant is guaranteed dispatch, some generators may still not make an offer if they predict the market clearing price to be below their variable costs. To prevent such capacity withholding, WESM enforces a "must-offer" rule on all generators, requiring all to offer their maximum available capacity at every trading hour. Again, this protocol is quite unique to WESM; in other markets, the "must-offer" rule is used only as a mitigation instrument during emergency or tight supply situations.

3 Auction Design and Electricity Prices

Although many of the protocols applied in WESM, such as the Pmin and must-offer rules, are designed to check the strategic behavior of market participants and put pressure on market clearing price, some quarters believe that the increase in electricity prices can be traced to the design of the auction. They claim that a different design could lead to lower prices and thus provide a better deal to consumers.

A feature of the current market design that baffles not a few observers is the uniform pricing scheme. A single price is applied to all generators even if they signaled their willingness to supply at different prices. Consider again Figure 2. Under uniform pricing, all generators selected to produce power (namely G4, G2 and G3) are remunerated at the SMP of PhP 2.00/kWh, even if G4 and G2 are willing to supply at much lower rates, PhP 1 and PHP 1.50 per kWh, respectively. Why should generators receive more than the amount they considered acceptable? If they were paid instead at the rates indicated in their offers, under a "pay-as-bid" or discriminatory pricing scheme, the total cost of generation and hence price paid by consumers would be much less. From a distributional perspective, the choice of uniform pricing over alternative design (i.e., pay-as-bid) is perplexing. To the extent that the difference between SMP and offer price is perceived as excess payment to generators, uniform pricing scheme is considered flawed and iniquitous because it allows generators to prosper at the consumers' expense.

As an alternative to uniform pricing, pay-as-bid or discriminatory pricing avoids the perceived iniquity of making consumers pay more than the price generators are willing to accept. Despite its intuitive appeal, pay-as-bid system has few adherents in the electricity market, among them the United Kingdom and Wales which shifted from uniform pricing in 2001. Several markets contemplated in following UK's lead, like California and New Zealand, but decided against it after careful study.

Most electricity markets stay with uniform pricing for market efficiency.[23] The scheme aligns price offers with marginal production cost which facilitates economic dispatch. The financial incentive of a generator under uniform pricing is to offer its output at average variable cost (proxy for marginal cost).[24] If it overbids, it runs the risk of not being dispatched as other generators may have lower offers. If it underbids, and it happens to be the marginal plant, it will incur losses for being dispatched. It is therefore in the best interest of a generator to bid at its average variable cost. When conditions are competitive, all generators will bid at their respective average variable costs. As a result, plants with lower variable costs, hence lower price offers, are dispatched ahead of others with higher marginal costs and price offers. Dispatching power resources in this manner ensures that electricity is produced at least cost.

Uniform pricing also allows generators to enjoy margins that provide incentives for investment in capacity and in an optimal generation mix. To produce electricity at the least cost, the system should have the right mix of base load, mid-merit and peaking plants to accommodate peaks and troughs in demand. The margin or gap between SMP and offer price is not an excess payment[25];

[23] In electricity markets, short-run (static) efficiency requires that least-cost suppliers are able to produce the right amount of output that consumers are most willing to pay for. This is achieved through economic dispatch. Long-run or dynamic efficiency of the system is attained when enough investments are generated to meet future capacity demand and prices converge to industry average cost.
[24] In practice, since marginal cost is an engineering concept that does not easily lend to measurement, average variable cost is used as proxy. Thus the two terms are used here interchangeably. The industry marginal cost is thus measured by the average variable cost or operating cost of the last (marginal) generator called on to supply.
[25] Even under cost-of-service regulation, a margin between the regulated price and supplier's variable cost is allowed to cover for return on investments, among others. Thus the margin cannot be simply viewed as excess payment.

rather it can be thought of as having two components: payment for fixed costs and economic profits.[26] Base load plants, which have low variable cost but high fixed cost, are usually offered at low prices so they can realize sufficiently large margins to cover fixed costs. In contrast, peaking plants, which have high variable cost but low fixed cost, are usually offered at high prices, hence have small margins under normal market conditions. It is only when prices are spiking sharply that the margins are large enough to allow peaking plants to recover their fixed costs and earn economic profits.

The price margins and volatilities associated with uniform pricing thus serve important purposes, namely to convey signal to new suppliers considering entry into the market and to mobilize investments in the type of plant required in the generation portfolio of the system. Wide margins should attract new generators to enter the market and compete for economic profits. Over the long term, the margins are smaller because of competition. But one should consider that because of relatively long gestation to plan and build new plants, it may take longer to compete away economic profits in electricity than in other markets.

In a pay-as-bid scheme, it would seem that consumers have captured the generators' profit since there are no discernible margins unlike in uniform pricing. Consumers are better off under this alternative pricing scheme if they pay lower electricity prices as a result, but do they? On closer analysis, the expectation of huge reduction of costs to end-users by changing the auction design is illusory.[27] Discriminatory pricing can produce lower prices only if one naively assumes that the bidding behavior of participants will remain the same after the auction rules have changed. Clearly, if the generators in the hypothetical market of Figure 2 maintain the same price offers as in uniform pricing, then paying them according to their offers will cut generation cost substantially, and therefore reduce electricity price. Yet it is not logical for these generators to offer the same prices. Realizing that they would be paid according to their offers, no generator will sensibly offer at marginal cost since such a rate does not cover for fixed cost nor contribute to economic profit. The incentive of a generator under pay-as-bid auction is to make an offer as close as possible to its estimate of SMP, or the operating cost of the last producer to be selected in the merit order. In the hypothetical case, G4 and G2 will each make an offer close to PhP2.00/kWh, instead of their respective marginal costs of PhP1 and PhP1.50 per kWh. How close would the offer be to PhP2.00/kWh depends on the generator's (i) "guess" of SMP or G3's offer, and (ii) balancing of risk of not being dispatched if the bid overshoots, and of revenues lost by bid shading. Obviously, the generators would have different guesses and assessment of risk. Nonetheless, if

[26] Economic profit refers to the residual revenue after all inputs have paid their economic value. In a competitive market, any positive economic profit is expected to be competed away by entry of new suppliers.
[27] The same conclusion was arrived at econometrically by Mahony and Denny (2011) for the Irish electricity market. The pool structure does not explain why Ireland has one of the highest electricity prices in Europe.

the generators behave as described in the foregoing, the average offer price under discriminatory pricing would be higher than under uniform pricing even if the two schemes produce the same market price and dispatch schedule.

An added wrinkle to the pay-as-bid proposition is that it may reduce the efficiency of plant dispatch. It proceeds from the logic that offers are based on individual generator's guess of SMP which may be erroneous at times. As Kahn (2001) explained, errors in predicting the SMP could result in a situation where offers for plants with lower operating costs exceed those for plants with higher operating costs, thus turning the merit order in reverse. While these errors will likely cancel out in the long-run, the possibility that offers in the short-run may be distorted already undermines the effectiveness of price signals in attracting entry and investments in the market.

One advantage that pay-as-bid mechanism is however deemed to have over uniform pricing is that it reduces the dominant suppliers' incentive to withhold capacity and their ability to collude. The argument goes that under uniform pricing, large generators can easily "game" the system by withholding capacity to lever up price. Under a pay-as-bid auction, capacity withholding can be effective only if a generator has control over a mix of capacity so that the gains achieved by its other units can offset the loss of revenue on the withheld capacity. Thus it would seem more difficult to gain from withholding capacity in a pay-as-bid market. Yet this reasoning is just as flawed as the expectation that a shift to pay-as-bid will produce dramatic reduction in price. In practice, generators adapt their bidding strategies to the auction rules to advance their interests.

To illustrate, refer back to Figure 2. With a SMP of PhP2.00/kWh, G2 realizes a margin of PhP125, 000 on the 250 MW it offered in the market. If it withholds 100 MW, i.e., offer only 150 MW of its actual capacity, the SMP increases to PhP5.00/kWh since G1 has to be dispatched to meet demand. While G2 foregoes some margin on the withheld capacity, it gains additional margin on the remaining capacity. On balance, G2 realizes a margin of PHP475, 000 by offering 150 MW. In addition, other generators, G4 and G3, also gain from G2's withholding since the higher SMP increases their margins too. Whether such benefit is derived accidentally or by design, it is clear that the other generators have incentive to collude with G2, tacitly or otherwise.

While it appears straightforward for G2 to gain from withholding capacity under uniform pricing, it may seem harder to achieve the same outcome under pay-as-bid. G2 can unilaterally raise the clearing price in the former, but not in the latter. To raise SMP under pay-as-bid, most generators must believe that the market clearing price could reach PhP5.00/kWh and adjust their price offers accordingly. G2's strategic withholding of capacity in one period must create a tight supply situation to convince other generators that the market would clear at PhP5.00/kWh in subsequent periods. If G2's action is persuasive, then adjustments in bids in subsequent periods reflecting such belief can be expected. Otherwise, G2's capacity withholding would be for zilch. At first blush, since it is necessary to get the beliefs of a good number of generators aligned, it looks more difficult to manipulate a market that is under a pay-as-bid scheme. But the other generators benefit as much from a higher clearing price, i.e., they all profit from making a "bad" guess of the SMP. Hence, they have sufficient incentives to collude tacitly with G2 to keep up the price. Furthermore, the repeated interaction of these generators (through hourly trading) makes it easier to enforce collusive behavior. Attaining the intended market outcome of capacity withholding in a pay-as-bid is therefore no more difficult as it is in a uniform pricing auction.[28]

4 Making Competition Work

The recent spike in electricity prices, triggered by fuel shortage and generator outages, has once again stoked public criticisms on the restructuring of the industry, particularly the reliance on the market in the determination of price. Yet much of the accusations on the debilities of the restructuring stem from a misunderstanding of the electricity market. It is worthwhile elucidating on some of these misconceptions.

First, price spikes are a natural occurrence in any market due to uncertainty in demand and supply, although they are probably more frequent in electricity than in other markets. This is due to electricity supply being vulnerable to a broad range of factors including fuel price shocks and plant outages, while electricity demand is basically unresponsive to price in the short-run. Clearly, spikes do not constitute a trend and should not be confused with the long-run pattern of electricity prices. That the price trend has moved opposite to the expected direction is a valid concern on the effectiveness of reform. But unless the price spikes are traced to inadequacy of competition, they cannot be the basis for indicting the market.

Second, substantial deviation of price from industry marginal cost in most markets is viewed as an indication of infirmities in market competition. This is not the case in electricity. In fact, that margin serves a venerable purpose, which is to compensate the capacity of plants that are seldom used. Absent such compensation, there is no incentive to build peaking plants which are necessary to maintain an optimal mix of generation, and hence produce electricity at the least cost.

Third, the vulnerability of the electricity market to exercise of market power and collusion is not a function of market design, as the previous section belabored. Electricity market is inherently vulnerable because of the characteristics of the good and network. Demand and supply must be balanced at all times, yet electricity cannot be stored and demand varies randomly and has low responsiveness to price. Worse, network congestion can fragment the market to the extent that the number of generators in actual competition depends on the strength and capacity of a densely meshed network. Given these, changing market design would not make the market impregnable to anti-competitive behavior since participants can adapt their behavior to new rules.

[28] Along this line, a recent paper (Heim and Gotz, 2013) documents the collusion of two largest firms in the German market for power reserves, providing the first empirical evidence to refute popular belief that pay-as-bid auction is less vulnerable to exercise of market power and collusion by dominant suppliers.

It is not fair to expect that a mere restructuring of the market would naturally produce a competitive outcome. A number of factors are critical for effective competition in the electricity market. Among them are adequacy of reserve margins and number of competing generators. Networks should be unencumbered and access must be open. Distributors should manage their portfolio well so they maintain bilateral contracts of different types and duration and have limited exposure to the spot market. Customers should be made capable of countering the market power of generators through demand responses. Impediments to entry, both on supply and demand side, should be removed. More important, effective market monitoring and surveillance should detect market power, reduce opportunities for capacity withholding, and sanction breaches of market rules. These essentials for competition in the electricity market should define the work of regulators and policy makers to give EPIRA a chance.

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