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How different electricity pricing systems affect the energy trilemma: assessing Indonesia's electricity market transition.

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How Different Electricity Pricing Systems Affect the Energy Trilemma: Assessing Indonesia's Electricity Market Transition

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Abstract:

Indonesia's current energy policy, which relies on cheap fossil fuels and focuses on two out of the three horns of the energy trilemma, namely, energy security and energy equity, may impede its efforts to higher shares of renewable energy sources. This paper develops three generic models that allow policymakers to analyze the impact of introducing a wholesale electricity market managed under either a nodal, a zonal, or a uniform pricing system on the three horns of the energy trilemma. It evaluates the models using a simplified network representation of the Indonesian electricity sector. The results indicate that under the model assumptions made and given the used input parameters as well as the used metrics for the three horns of the energy trilemma, a uniform pricing system might help Indonesia to balance its energy trilemma.

JEL Classification: Q400, Q410, Q420, Q480, L510, L110

Keywords: Electricity Pricing System; Electricity Market Liberalization; Energy Trilemma; Indonesia; Renewable Energy Sources.

1 Introduction

Historically, the focus of policymakers was primarily on achieving the first two horns of the energy trilemma, namely energy security and energy equity (Heffron et al., 2018). In particular, during the first wave of global electricity market restructuring[1] that began in Chile, England and Wales, and Norway in the mid-1980s (Hogan, 2002), policymakers aimed to improve both the operational and the economic efficiency of their energy systems (Conejo and Sioshansi, 2018). Corresponding reforms intended to improve the ability of the energy system to provide consumers with electricity reliably (referring to energy security) and at low costs (referring to energy equity). As stakeholders within the electricity sector generally viewed fossil fuel-based power plants as being more reliable and more cost-efficient than renewable energy sources (RES), project developers have primarily invested in conventional generation capacity. As the negative consequences of fossil fuel-based electricity generation are becoming increasingly apparent in many countries, policymakers around the world nowadays are introducing new reforms to transform their energy systems from high-carbon into low-carbon systems. In particular, policymakers generally aim to replace conventional power plants with RES. Despite this circumstance, RES uptake is still slow in many countries – this is particularly true for developing as well as emerging countries (Tabrizian, 2019) – and investment in RES is expected to even decrease as a result of the COVID-19 pandemic (IEA, 2020b). Therefore, policymakers should rebalance the energy trilemma and place more emphasis on environmental sustainability if the RES uptake and the energy transition are to be successful (Heffron et al., 2020).

One prime example of a country where a misfit of RES targets and actual policy reforms is apparent is Indonesia (Gunningham, 2013). For many years, policymakers in Indonesia have relied on fossil power plants, mainly coal-fired power plants, to provide their population with reliable (i.e., energy security) and affordable (i.e., energy equity) electricity. Since Indonesia has not yet made much progress with regard to the liberalization described above, its current energy system is still heavily dependent on state control. As the country has considerable coal, gas, and oil resources, policymakers currently see fossil power plants as a low-cost way to generate electricity. In 2014, the government announced ambitious plans to increase the share of RES in Indonesia's energy mix (Kemenkumham RI, 2014). Given these targets, reforms of Indonesia's energy system are now necessary to shift from fossil fuels to RES. However, the past reforms that the country undertook to make renewables more cost-competitive with conventional power plants have so far proven to be less successful in Indonesia (Ditjen EBTKE, 2019). Therefore, the government is in search of clear policy directions to push the RES uptake in the coming years. In addition to the slow start some countries have made, the COVID-19 pandemic stresses the need to accelerate how Asian countries meet the SDGs (ADB, 2020b).

While the literature has discussed some small- to medium-scale reforms with respect to increasing the share of RES in the Indonesian energy system (see, e.g., ADB (2019) or Burke et al. (2019)), in our paper, we instead address a major reform of the Indonesian electricity sector, namely the introduction of an energy-only wholesale market for electricity that currently does not exist. We also analyze new electricity pricing systems, which relate to the method of implementing wholesale prices, for instance in the form of a nodal pricing, a

[1] The terms 'restructuring' and 'liberalization' are synonymous and refer to "attempts to reorganize the roles of the market players, the regulator and/or redefine the rules of the game, but not necessarily 'deregulate' the market" (Sioshansi (2006)); accordingly, we use the two terms interchangeably in this paper.

zonal pricing, or a uniform pricing system (Weibelzahl, 2017). These three systems differ in the extent to which electricity trade accounts for the scarce transmission capacities of the electricity network and whether post-trade redispatch is necessary. We rely on experiences from countries that have already successfully restructured their energy systems, including countries in Europe and the US.

Central to our research is the idea that any major reform that aims at improving energy sustainability in Indonesia must also meet the other two ongoing major objectives of Indonesian policymakers (i.e., energy security and energy equity). Hence, the focus of our research is on answering the following research question (RQ):

How can different pricing systems support Indonesia in balancing its energy trilemma?

To answer our RQ, we develop an economic model that allows us to analyze private and public investment decisions in liberalized electricity markets; that is, we consider both generation and transmission investments. In this context, generation investments refer to investments by private market participants in new electricity generation technologies such as coal power plants or solar photovoltaics (PV); transmission investments refer to investments by public market participants in new transmission technologies such as transmission lines. In particular, we develop a model for each of the three standard pricing systems that have emerged from the first wave of electricity market restructuring, specifically nodal pricing, zonal pricing, and uniform pricing (Weibelzahl, 2017). The general set-up of each of the three models is based on the related literature, e.g., Grimm et al. (2016) or Weibelzahl and Märtz (2020, 2018). The three model variants allow us to examine and to compare the investments obtained under each of the three pricing systems and the respective impact on the energy trilemma. To illustrate the applicability of our model, we evaluate it with a simplified version of the Indonesian electricity network, focusing particularly on the Sumatra and Java–Bali electricity subnetworks. Subsequently, we outline a first transformation pathway for a more sustainable transition to a low-carbon economy in Indonesia.

With our paper, we aim to contribute to research and practice in at least four ways. First, based on our models, we illustrate how the introduction of liberalized markets, and of market-based pricing in particular, may support countries like Indonesia in balancing the energy trilemma and in reaching goals concerning increased RES penetration. There is a research gap, especially regarding the effects of different pricing systems on the energy trilemma, which we would like to address with this paper. Second, building on the experiences from other countries that have already implemented corresponding pricing mechanisms, our paper illustrates how the models may work in practice and specifically how they may work in Indonesia, an emerging lower-middle-income economy (World Bank, 2020c). Third, our paper analyzes and discusses the first and preliminary results using a simplified network representation of Indonesia. Fourth, our model may generally provide policy-relevant insights for investment institutions (e.g., for development banks or other investment funds) by supporting decisions on funding strategies concerning energy transition projects.

This paper is organized as follows. Section 2 first presents the insights and experiences that we obtained from the existing literature on electricity pricing systems; second, it outlines the status quo of the Indonesian energy system and previous reform attempts. In Section 3, we develop our three pricing models. Section 4 presents the data basis for the simplified Sumatra and Java–Bali electricity networks that we use in our evaluation. Section 5 discusses the numerical results for our three pricing systems. The penultimate section of our paper, Section 6, summarizes main implications for research and policymaking. Finally, Section 7 concludes the paper.

2 Theoretical background

2.1 Electricity market liberalization

Within the last decades, the era of liberalization has affected many energy sectors worldwide (Pollitt, 2012). In the case of electricity systems, restructuring has typically taken shape through the introduction of wholesale markets for electricity and a corresponding implementation of different electricity pricing systems (Weibelzahl, 2017). Policymakers in Chile, England and Wales, and Norway were among the first to introduce wholesale markets for electricity (Hogan, 2002)[2]; others in many more countries around the world followed their example. By introducing these new markets, policymakers aimed at improving both the operational and the economic efficiency of electricity sectors to be able to provide consumers with electricity reliably (i.e., energy security) and at low costs (i.e., energy equity) (Conejo and Sioshansi, 2018). Not only by creating markets for free trade but also by breaking up vertically integrated monopolies, policymakers intended to foster competition, thereby lowering prices and incentivizing private project developers to invest in generation capacity (Pollitt, 2012).

Wholesale markets for electricity are markets where electricity is bought and sold before being delivered to end consumers via the electricity network. The two main market participants are electricity generating companies and consumers/retailers. While the former freely compete with each other selling their output, the latter buy electricity in order to consume it or to sell it to their end consumers (e.g., households). Wholesale trading typically takes place on an energy exchange or bilaterally (over-the-counter). On wholesale markets, participants can trade products (i.e., electricity) with different time horizons, ranging from years to a couple of minutes. In addition to electricity generating companies and retailers, other stakeholders in wholesale markets are, for example, exchange operators, intermediaries (e.g., brokers), and aggregators (e.g., of flexibility).

2.2 Electricity pricing systems

Various forms of wholesale electricity markets have emerged around the world. Typically, they have in common a transmission sector that remains highly regulated, as are the associated public network investments (Vogelsang, 2006). However, there are differences, particularly with respect to how wholesale market trade is organized using different design options for trade between market players, including electricity generating companies and consumers. The literature has mainly discussed three different electricity pricing systems, namely nodal pricing, zonal pricing, and uniform pricing (Gan and Bourcier, 2002; Leuthold et al., 2008; Weibelzahl, 2017).[3] These different pricing systems vary in the

[2] With the passing of the 1982 Electricity Act, which is still the most important law for Chile's electricity market, Chile became the first country in the world to liberalize its electricity market. In England and Wales, liberalization began with the 1998 Electricity Act; in Norway liberalization began with the 1990 Energy Act. For an overview of the historical developments since the adoption of these laws in Chile, England and Wales, and Norway please refer to Pollitt (2004) and Eikeland (1998).

[3] While we consider the three pricing systems (i.e., nodal, zonal, and uniform pricing) individually in this paper, it is also possible to combine these pricing systems.

way in which they manage the limited transmission capacities of the network and in the way in which the pricing rules take these scarce capacities into account.

Under a nodal pricing system, all the economic and physical restrictions of the system are perfectly "integrated"; that is, the market equilibrium takes the relevant generation-related, consumption-related, and transmission-related constraints into account (Singh et al., 1998). Therefore, resulting node-specific prices adequately reflect the local and temporal scarcity in the system in the form of price peaks. This may ensure efficiency of the system; for original work on nodal pricing, see, for example, Bohn et al. (1984), Schweppe et al. (1988), Hogan (1992), and Chao and Peck (1996).

In contrast, a zonal pricing systems pools nodes into different pricing zones that share a common price (Bjørndal and Jørnsten, 2007, 2001). Hence, the zonal system considers the physical restrictions between the assumed price zones while neglecting the intra-zonal transmission restrictions. This requires ex post redispatch of the transmission system operator (TSO) resulting from the relaxation of the relevant physical transmission rules within zones during spot market trade, i.e., the responsible TSO may not be able to transport the generated electricity to the corresponding consumers. Therefore, redispatch takes place in a second step (i.e., after spot market trade), restoring physical feasibility at minimal cost (Burstedde, 2012; Egerer et al., 2016). In this context, redispatch refers to either the upregulation or the downregulation of different electricity generators/consumers to ensure feasible electricity flows in the network without an overflow on the existing transmission lines; for original work on zonal pricing, see, for example, Walton and Tabors (1996), Stoft (1997), Bjørndal et al. (2003), Bjørndal and Jørnsten (2007), and Oggioni and Smeers (2013).

Finally, a uniform pricing system completely ignores the physical transmission constraints at the electricity spot market (Kahn et al., 2001). It accounts only for generation-related and consumption-related constraints. As a direct consequence, redispatch takes place in a second step to deal with corresponding transmission infeasibility.

The chosen pricing systems directly determine the profitability of possible private investments in new generation capacity. Obviously, while the investors/operators of a power plant receive no location-specific investment signals under a uniform pricing system, nodal prices reward investments in locations where the generation capacity is scarce to a greater extent. Nevertheless, the large number of different prices in a nodal pricing system makes it highly complex and electricity consumers may perceive it to be unfair, as people in different network locations will typically pay different prices. In addition, low liquidity at nodes and possible market power (abuse) are discussed as other possible drawbacks of nodal pricing. Even though, zonal or uniform pricing may circumvent such problems, these systems especially yield very costly redispatch that is expected to further increase with an increasing share of decentralized RES and the typically delayed transmission line expansion, which is necessary to be able to transport electricity from the location of production to the location of consumption. For example, in Germany these costs regularly amount to 1 billion euros per year. Overall, the issue of choosing an adequate pricing system is a highly complex decision for policymakers. In particular, for all three of the systems, there are valuable experiences of their benefits and challenges from countries that have already liberalized their electricity sectors, for example, the US (currently using nodal pricing; see, e.g., Gil and Lin (2013)), Norway (currently using zonal pricing; see, e.g., Bjørndal and Jørnsten (2001)), and Germany (currently using uniform pricing; see, e.g., Müsgens et al. (2014)).

Against this background, Table 1 summarizes some of the main benefits and challenges of the three different pricing systems that countries such as Germany, Norway, and the US have experienced in the past. It also underlines that there is no "best" pricing system, but that the three systems may have very different characteristics, which must best reflect the current circumstances of a given country, e.g., the issue of market power under nodal pricing may be more severe if currently there is only a very limited number of generation companies. In addition, the issue of price "unfairness" is typically the more severe, the higher network congestion is, which yields a complex interdependency with network expansion projects. Please note that Table 1 takes a costs and operations perspective on the three pricing systems; it is therefore limited with respect to other important perspectives such as, e.g., sustainability.

Table 1. Exemplary experiences with different pricing systems. Source: Authors' creation from the review of: Bjørndal and Jørnsten (2001), Gil and Lin (2013), Müsgens et al. (2014), Weibelzahl (2017).

	Benefits	Challenges
Nodal pricing	• Efficient dispatch of generation • Local signals/incentives in long-run investments (with possibly reduced need for network investments) • No redispatch necessary • Higher transparency, as all assets have to bid into the market	• High system complexity • Many small submarkets • Possibly low competition and market power abuse in nodes • Fluctuating and possibly instable local prices • Forward markets bear basis risk • Local changes in grid configuration have high impact on price formation for all participants • Usually comes with an ISO, i.e., centralized dispatch
Zonal pricing	• Reduced number of different prices (compared to nodal pricing) • High intra-zonal competition • Price stability	• Possibly inefficient dispatch of power plants • Reduced local signals for flexibility • No local signals/incentives for long-run investments • Difficult determination of zonal boundaries • Possibly high redispatch costs and associated reallocation issues • Challenge of defining adequate remuneration for redispatch services • Depending on the respective implementation (e.g., the case of Italy) there is a high strain on market coupling algorithms • Depending on the implementation (e.g., EPADs in the Nordics), hedging may be difficult and thus prevail local incumbents • Frequent re-definition of zonal boundaries creates economic uncertainty

Uniform pricing	• High market liquidity; in particular, low potential for market manipulation and abuse • Low system complexity • Relatively high competition • Price stability • Liquid forward markets • Basis-risk free hedging possible	• Possibly inefficient dispatch of power plants • Possibly inefficient long-run investments (e.g., in generation) • Typically high redispatch costs and associated reallocation issues

Currently, in almost all countries, the power transmission sector is still highly regulated, which implies that some kind of public entity such as a TSO, a regulator, or the government, often makes network investment decisions. When the public entity assesses and decides on a possible network extension projects, it is highly nontrivial to anticipate the actual impact of the corresponding network investment on electricity prices. In turn, price changes may influence private investments in new generation capacity, as described above. As different pricing systems vary in their representation and consideration of network constraints, the chosen pricing system will ultimately have a severe impact on the question of which public network investments are necessary to avoid negative effects on the investment behavior of private companies. This clearly highlights the high degree of interdependency of the different investment decisions. We illustrate the stylized decision sequences accounting for both long-run investment decisions and short-run market clearing in Figure 1. This sequence mainly builds on the timing of the corresponding decisions: Public network investment choices (denoted as decision level 1 in the remainder of this paper) are followed by expected private generation investments and spot market trade (which we formally aggregate into a single decision level 2 in Section 3). In the case of zonal and uniform pricing, spot market trade is followed by redispatch of the TSO (denoted as decision level 3) to restore the transmission feasibility.

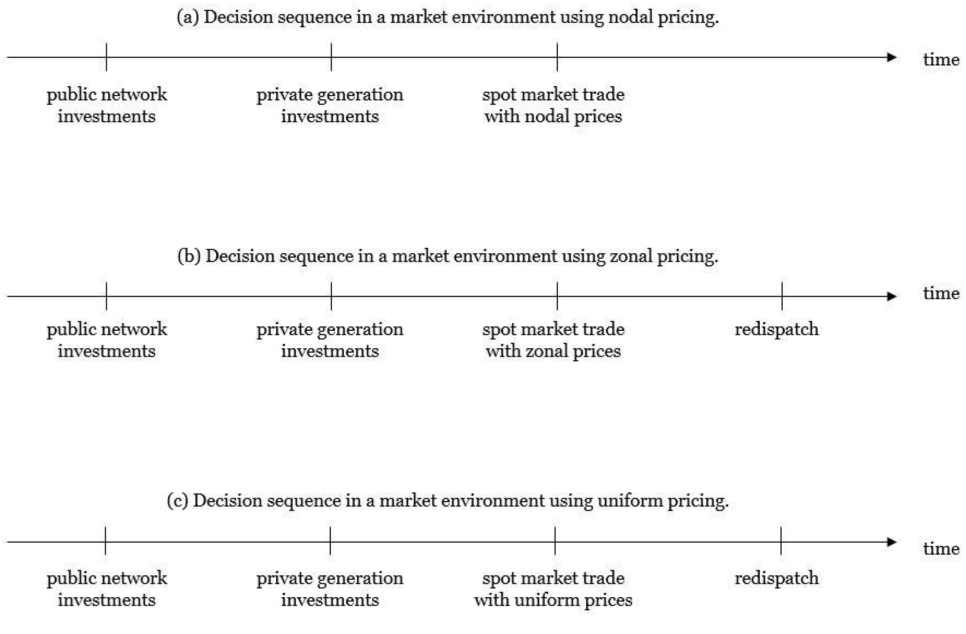

Figure 1. Decision sequences under different pricing systems. Source: Authors' creation.

2.3 The Indonesian energy system

With more than 267 million citizens, Indonesia is the world's fourth most populous country (World Bank, 2019b). It has the biggest economy in Southeast Asia and ranks 16th among the world's economies in terms of total GDP (World Bank, 2019a). Positioned between the Indian Ocean and the Pacific Ocean, Indonesia is additionally the world's biggest island state, consisting of 17,508 islands, around 6,000 of which are inhabited. With respect to its electricity sector, the term "archipelago" perfectly describes the Indonesian electricity network, which consists of eight major and around 600 isolated networks (Burke et al., 2019).

During the first wave of global electricity market restructuring, Indonesia made its first privatization efforts by opening its electricity generation sector to independent power producers (IPPs) in the 1990s (Maulidia et al., 2019). Today, however, there are only a few IPPs in Indonesia and the liberalization appears to be incomplete. In particular, the state-owned enterprise *Perusahaan Listrik Negara* (PLN) and its subsidiaries still own more than 75% of the generation capacity in the country (Maulidia et al., 2019). No further significant privatization has taken place, which is why—except for electricity generation— the state controls Indonesia's electricity sector; that is, PLN controls the network and sells electricity to consumers (Burke et al., 2019). The current organization of the Indonesian electricity sector is as a single-buyer market (Sakya et al., 2006). Typically, under such a market design, countries preserve an *artificial* monopoly over the electricity sector even after formally unbundling the vertically integrated state-owned enterprise (i.e., PLN in Indonesia) (Lovei, 2000). In fact, PLN buys all the electricity generated in Indonesia (as a single buyer) and resells it to electricity consumers at regulated prices.

In terms of energy security, Indonesia has struggled to provide its citizens with access to electricity and has performed poorly for many years in this respect compared with other Southeast Asian countries (Maulidia et al., 2019). In 2010, roughly 14 million Indonesians (i.e., 5.85% of the population) had no access to electricity (World Bank, 2020a), which is why improving the electrification rate has been a key priority of policymakers in the past decade (Maulidia et al., 2019). Indeed, by 2017, the electrification rate had improved significantly: now only 4.9 million Indonesians (i.e., 1.86% of the population) are without electricity access (World Bank, 2020a). However, the electrification ratios still vary between different regions; while the overall electrification rate of Indonesia is 98.89% (2019), it is lower in regions like East Nusa Tenggara (85.84%) or Maluku (91.34%) (MEMR, 2020). Power cuts are still frequent for many Indonesians across all regions (Gunningham, 2013).

In terms of energy equity, Indonesia is making efforts in keeping retail prices low for its citizens to combat poverty. In 2010, roughly 38 million Indonesians (i.e., 15.7%) lived in poverty, that is, on $1.90 a day (World Bank, 2020b). Against this background, ensuring low retail prices for electricity was and still is a key measure for the Indonesian Government in its fight against poverty (Maulidia et al., 2019). This is why retail prices are set by the government in Indonesia, as described above.

Retail prices in Indonesia vary by type of customers (Burke and Kurniawati, 2018), with the main customer types being residential, industrial, business, and social customers (PT PLN, 2019a). In the region of Aceh (Sumatra), for example, it was the residential customers who in 2018 on average had to pay the lowest tariffs (0.04 $/kWh), followed by social customers (0.05 $/kWh), business customers (0.06 $/kWh), and industrial customers (0.07 $/kWh) (PT PLN, 2019a). The tariffs also differ regionally (Maksum and Lambok, 2014; PT PLN, 2019a). Since the government kept the electricity prices artificially low (even below the PLN's costs of supplying electricity) in order to combat poverty and promote international competitiveness, Indonesian taxpayers had to heavily subsidize electricity generation (Burke and Kurniawati, 2018). In 2015, for example, the subsidies to coal amounted to approximately $644 million (IISD, 2019). Although the government had initiated extensive electricity subsidy reforms, in the course of which the tariffs were raised, many customers still receive subsidies in the form of discounted electricity tariffs (Burke and Kurniawati, 2018); especially residential customers are heavily subsidized (IISD, 2019). Compared to the rest of the world, in 2019, the average price of electricity in Indonesia was at roughly 70% of the world median (World Bank, 2021).

To improve both energy security and energy equity, Indonesia's policymakers have focused on the expansion of fossil power plants—above all, coal-fired power plants. Here, the policymakers base their rationale on the supposed advantages of coal over other options. Not only does Indonesia have large domestic coal reserves, but also its coal-fired power plants are capable of providing the necessary base load power (Gunningham, 2013). Further, policymakers view coal-fired power plants as being easy to finance and quick to build. To support the domestic coal production and thereby ensure an adequate electricity supply and lower the costs of electricity generation, the government ultimately subsidizes fossil fuels like coal or oil.

This focus on an energy supply chain based on fossil fuels has resulted in a situation that mainly neglects the third horn of the energy trilemma, energy sustainability, in Indonesia. Today, RES like solar or wind power only make up a fraction of Indonesia's energy mix—despite the country having huge renewable potential (Dutu, 2016). Only in 2014, the government announced ambitious goals to develop RES in Indonesia: RES are to account for 23% of the energy mix by 2025 and even 31% by 2050 (Kemenkumham RI, 2014; Maulidia et al., 2019); see Figure 2 for an overview of the historical trend of electricity generation by source in Indonesia. Recent estimates, however, have suggested that Indonesia will not reach its 2025 and 2050 goals at the current RES development rates (Burke et al., 2019). One of the key barriers to RES development is the fact that the current design of the Indonesian energy system does not allow RES to become competitive with fossil power plants (Burke et al., 2019; Maulidia et al., 2019). What is therefore necessary is a fundamental reform of the energy

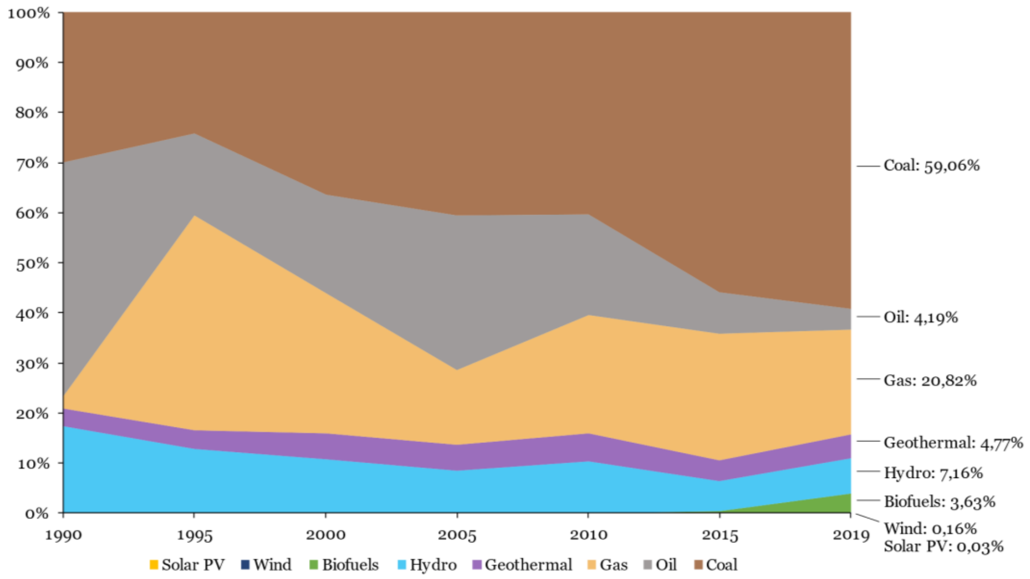

Figure 2: Electricity generation by source in Indonesia, 1990-2019. Source: Authors' creation based on IEA (2020a).

system so that Indonesia is able to achieve its RES targets—and avoids ending up locked into a fossil fuel future (Liebman et al., 2019).

Indeed, the Indonesian Government has launched a series of reforms over the past ten years to strengthen RES. However, these reforms were not very successful in terms of the market penetration of RES. For example, within the last ten years, the Ministry of Energy Mineral Resources (MEMR) has made repeated efforts to push the development of solar PV in Indonesia. From 2013 onwards, the MEMR tried to improve the situation for developers through five key regulations (i.e., No. 17/2013, 19/2016, 12/2017, 50/2017, and 4/2020) (Kennedy, 2018). In 2013, the MEMR introduced the first auction program for new solar PV capacity in Indonesia (Reg. No. 17/2013) (MEMR, 2013). Although the program covered 140 MW in over 80 locations, it only realized two projects due to protests from PLN and local manufacturers, who opposed the favorable tariffs for solar PV developers. Moreover, it was not private investors but rather the two state-owned companies that implemented the two actually realized projects (Kennedy, 2018).

In 2016, the MEMR introduced a feed-in tariff for solar PV projects, collectively covering at least 5,000 MW (Reg. No. 19/2016) (MEMR, 2016). However, the regulation included restrictions on the project size and foreign ownership, discouraging international developers. Only a couple of months later, it abandoned these feed-in tariffs (Kennedy, 2018). Instead, from 2017 onward, the MEMR regulated the tariffs that solar PV developers can charge to PLN (Reg. No. 12/2017) (MEMR, 2017b), basing the tariffs on and limiting them to a maximum of 85% of the local and national average costs of generation. In addition, it differentiated them geographically (Kennedy, 2018). Reacting to stakeholders' new protests, it eventually replaced Reg. No. 12/2017 with Reg. No. 50/2017 (MEMR, 2017a). One major difference between the two regulations is that the new one forced RES developers to transfer ownership of their facilities to PLN on completion of power purchase agreements. In combination with the tariff limits, the situation for investments in RES-plants was not attractive in terms of recovering project costs (Kennedy, 2018). In 2020, the MEMR introduced Reg. No. 4/2020, which stipulates amendments for Reg. No. 50/2017 to overcome key items in Reg. No. 50/2017 that had become barriers to RES development (e.g., at the end of the power purchase agreements, IPPs no longer had to transfer the ownership of their facilities to PLN). The amendments provide more flexibility for investors and aim to accelerate RES growth in Indonesia.

To summarize, Indonesia's energy policy to promote RES development to date has suffered from several major changes in direction (e.g., the shift from feed-in tariffs to regulated tariffs) as well as from an overall tendency to retain at least some state control over new projects. The government's RES development strategy has therefore not proven to be successful so far. Ultimately, the government is in search of clear policy directions to promote an increase in the number of RES-plants in the coming years. In the next section, we will therefore develop a model to assess the impacts of a major reform in Indonesia that builds on the introduction of an energy-only wholesale market.

3 Model Framework

This section presents the model framework used in this paper. A formal model description is presented in Appendix A.

3.1 Planning horizon and electricity network

$T = \{1, \ldots, |T|\}$ describes the finite planning horizon. In addition, we assume an electricity network $\mathcal{G} = (N, L)$ that consists of a set of network nodes N and a set of transmission lines L interconnecting the different nodes. Tables B.1, B.2, and B.3 in Appendix B provide a short summary of the main sets, parameters, and variables that we use in our paper.

We describe each transmission line $l \in L$ using its maximal transmission capacity $\bar{f}_l$ and its susceptance B_l. Accounting for possible network investments from a public entity like a responsible TSO, the subset $L^{\text{new}} \subseteq L$ collects all the candidate transmission lines for the responsible TSO's investments. In analogy, subset $L^{\text{ex}} \subseteq L \setminus L^{\text{new}}$ collects all the existing transmission lines of network $\mathcal{G}$.

As new transmission lines are typically characterized by huge fixed costs, we model network investments as zero–one decisions using a binary variable $w_l \in \{0, 1\}$. This has established as a standard in literature, see, for example, Jenabi et al. (2013) and Grimm et al. (2016). w_l is equal to one if and only if the TSO builds $l \in L^{\text{new}}$. The given cost parameter i_l describes investments in line l.

3.2 Electricity demand

$C \subseteq N$ collects all the nodes of the network containing electricity consumers. We assume an elastic long-term demand for each time period t and demand node $c \in C$ using the following linear inverse demand function:

$$\pi_{c,t}(d_{c,t}) = a_{c,t} - b_c d_{c,t} \qquad \forall c \in C, t \in T. \tag{1}$$

In the inverse demand equation (1), $d_{c,t}$ denotes the endogenous demand quantity of consumer c in time period t while $a_{c,t}$ and b_c are the ex-ante given parameters that specify the actual demand function. $\pi_{c,t}(d_{c,t})$ gives the resulting electricity prices for a traded quantity of $d_{c,t}$. We note that the assumption of an elastic demand is quite common in the electricity market literature; see, for example, Chao and Peck (1996), Bjørndal and Jørnsten (2001), Bjørndal et al. (2003), Ehrenmann and Smeers (2005), Bjørndal and Jørnsten (2007), Pechan (2017), or Weibelzahl and Märtz (2020).

Using the above inverse electricity demand function, the following gives the gross consumer surplus, which describes the aggregated monetary consumer benefits:

$$\sum_{t \in T} \sum_{c \in C} \int_0^{d_{c,t}} \pi_{c,t}(h) \mathrm{d}h = \sum_{t \in T} \sum_{c \in C} \left(a_{c,t} - \frac{b_c}{2} d_{c,t} \right) d_{c,t}. \tag{2}$$

3.3 Electricity generation

Renewable electricity generators. Let us use a set of carbon-neutral, renewable electricity generators R. The subset $R_n \subseteq R$ comprises all the renewable generators that are located at network node $n \in N$.

We assume that the set of generators R consists of both existing and candidate generators; that is, we partition the set of renewable generators R into a set of existing generators R^{ex} and a set of candidate generators R^{new}. Corresponding investments of i_r per unit of installed gross (or maximum) generation capacity $\bar{x}_r^{\text{new}}$ arise for each candidate generator. In analogy, $\bar{x}_r^{\text{ex}}$ describes the installed gross capacity of an existing generator.

Accounting for fluctuations in power generation, for each generator r, we assume relative availability $\alpha_{r,t} \in [0,1]$ of electricity generation capacity in time period t. As this parameter refers to the relative availability of the corresponding resources, like wind or sun, it depends both on the time period t and on the location of the generator; for example, at night, there will be no sun, meaning that there is availability α of zero. Thus, in each time period and for each renewable generator, $\alpha_{r,t}\bar{x}_{r,t}$ limits the net electricity output. Given this capacity bound, we then model the actually chosen electricity output using the variable $x_{r,t} \geq 0$. This implies that once RES investment is made, the generator can choose how much electricity to provide up to the maximum net capacity that is time and location specific due to weather constraints. Note that the model neither assumes renewable generation to be constant over time nor to be stochastic, which may be analyzed by future research. Instead, solar and wind generation is one-sided-dispatchable accounting for the given weather patterns. The latter is not the case for conventional generators, which are typically weather-independent (see below). $v_r \geq 0$ describes the variable per-unit generation costs.

Conventional electricity generators. Set G contains all the conventional electricity generators in the system. Analogous to the renewable generators above, we describe with $G_n \subseteq G$ the subset of conventional electricity generators located at network node $n \in N$.

We describe generator $g \in G$ using its variable per-unit generation cost $v_g \geq 0$. The endogenous variable $y_{g,t} \geq 0$ gives the realized electricity output of generator g in period t. Similar to renewable generators, we partition the set of conventional generators G into a set of pre-existing generators G^{ex} and a set of candidate generators G^{new}. It is possible to invest in the latter with investments of i_g per unit of installed generation capacity $\bar{y}_g^{\text{new}}$. For all existing generators, the corresponding generation capacity is $\bar{y}_g^{\text{ex}}$ and does not depend on weather conditions.

3.4 Multi-level optimization problem(s)

Given the decision sequence described in Section 2.2, we translate the corresponding economic, hierarchical Stackelberg game into a mathematical, multilevel optimization problem. In such multi-level optimization problems, decisions on one level are made in anticipation of the optimal reactions of the subsequent lower-level decision makers to the decision made on the upper levels. For example, public network expansion on level 1 is made in anticipation of private generation investments as well as of spot market and redispatch market outcomes determined on the following levels. On the opposite, lower-level decisions like the (zonal) spot market trade depend on optimal network expansion decisions made on level 1. As such, hierarchical, multilevel problems constitute complex optimization problems that capture optimal decision responses. This method is an established standard in the literature for modelling and analyzing electricity-pricing systems (Grimm et al., 2016; Weibelzahl and Märtz, 2020, 2018). A more formal model presentation can be found in Appendix A.

4 Data, assumptions, and evaluation set-up

In this section, we describe the set-up we use to evaluate our models. In particular, we describe the data we use to parameterize the models and explicitly state where and why we made which assumptions.

4.1 Electricity network

Our network of Sumatra and Java–Bali consists of 16 network nodes: one node per province in the geographical units of Sumatra and Java and one node for Bali in the geographical unit of the Lesser Sunda Islands; see also Table C.1 in Appendix C where we provide additional information on the data that we used. We based our data concerning the existing transmission lines on IESR (2019a) and MEMR (2019). Currently, the two islands of Sumatra and Java–Bali are not connected. We allowed investments in new transmission lines between neighboring nodes, as well as between nodes 6, 7, and 9 (Sumatra) and nodes 10, 11, and 12 (Java), to enable a possible interconnection between the two islands (assumption 1). In principle, it would be possible to connect Sumatra and Java-Bali via other nodes; however, the cost of the longer electricity lines that would be required would, presumably, be too high. Therefore, we limit the possibilities of building new electricity lines between the two islands to the nodes previously mentioned. Ultimately, eight different lines may be built between the two islands. For the cost parameters of network investments, we referred to Chang and Li (2015).[4] Figure 3 illustrates our network topology with the considered nodes and lines.

[4] Note that all investment costs in our model instantiation (including, e.g., investment costs of power plants) relate to the 24 hours of a representative day—and not to the complete technical lifetime of the assets.

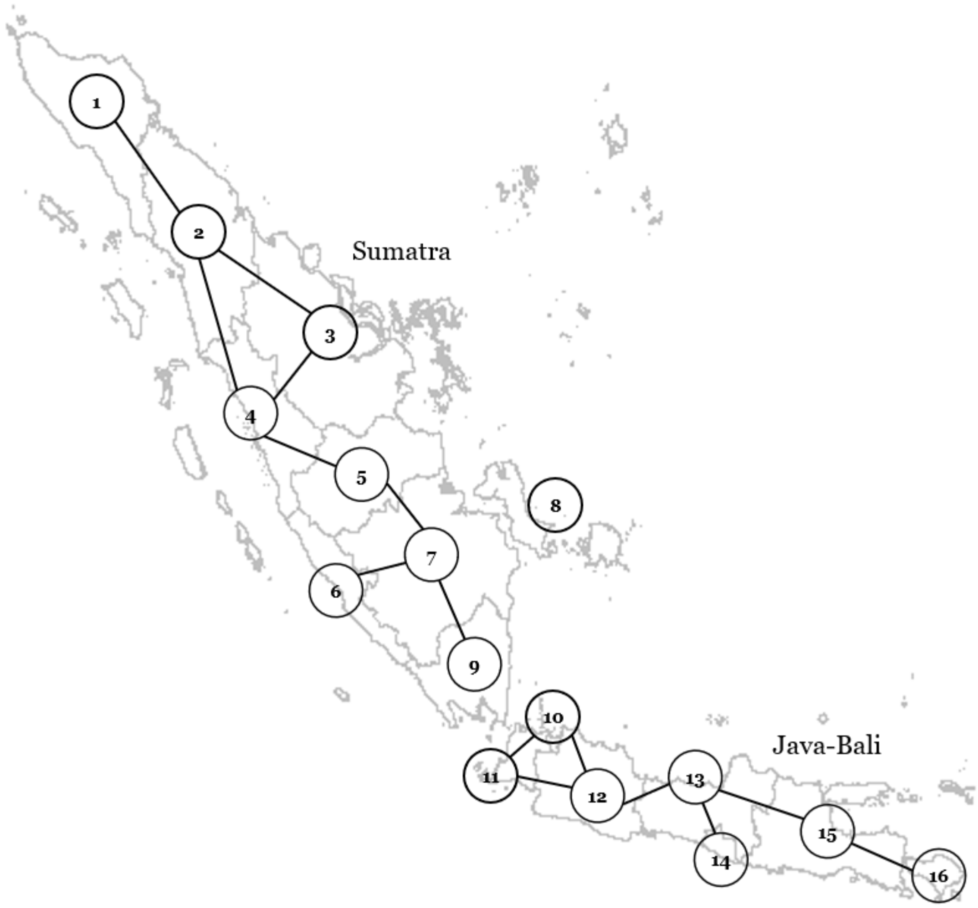

Figure 3. Network topology illustrating the considered nodes and lines. Source: Authors' creation.

4.2 Electricity generation

We based the data concerning the existing generation capacities on PLN's 2018 *Rencana Usaha Penyediaan Tenaga Listrik* [Power Supply Business Plan] (PT PLN, 2018); see Table C.2 in Appendix C for an overview of the existing generation capacities located at each node. We considered all the power plants that are currently installed as existing power plants in our model (assumption 2). We therefore do not include power plants currently under construction in Indonesia in our analysis. This is mainly due to lack of data. As Table C.2 shows, currently around 88% of the installed generation capacity relates to conventional power plants, with coal-fired power plants accounting for 53% of the total installed generation capacity.

Table 2. Techno-economic parameters of generation technologies. Source: Authors' creation based on IESR (2019b).

Technology	Lifetime (Years)	Efficiency (%)	Investment Cost ($/kW)	Variable Cost ($/MWh)[a]
Coal, existing	30	34	-	26.8
Coal, new	30	42	1,525	22.1
Gas, existing	25	34	-	69.7
Gas, new	25	56	825	45.3
Diesel	25	46	800	325.5
Large hydro	25	-	1,953[b]	0.55
Small hydro	25	-	3,100	0.55
Geothermal	30	-	4,550	0.25
Wind	25	-	1,750	-
Solar PV	25	-	950	-
Biomass	25	-	1,750	3

[a] Variable cost include variable operation cost and fuel cost.

Table 2 summarizes the techno-economic parameters of each generation technology. While the respective values are based on IESR (2019b) in line with Handayani et al. (2017), we estimate the investment costs for large hydro at 63% of small hydro (assumption 3). We make this assumption because we could not find any data regarding the investment costs for large hydro.

Except for coal-fired power plants, we allowed investments in new generation units at all nodes. We restricted investments in new coal-fired power plants to those nodes where coal-fired power plants are currently at the planning or construction stages (assumption 4), that is, nodes 2, 7, 9, 12, 13, and 16 (Global Energy Monitor, 2020). This approach in particular aimed to exclude the possibility of building coal-fired power plants in regions where this is probably not possible due to real-world restrictions, such as geographical conditions or political resistance to coal-fired power plants. For investments in RES, we set limits that determine the maximum amount of cumulated capacity that it is possible to invest in at each node (assumption 5). We intended these limits to reflect the respective potentials of each RES technology in each province. Except for hydro power, we took the latter data from MEMR (2017c); we base the hydro power limits on Ditjen EBTKE (2016).

4.3 Electricity demand

As we could not directly observe the real-world electricity demand functions of consumers in Indonesia because the government still sets the prices, we calibrated hourly inverse demand functions for a representative day (with 24 hourly time intervals) at each node (assumption 6). We based our derivation of inverse demand functions on the cumulative annual demand at each node (PT PLN, 2019b), the average retail price at each node (PT PLN, 2019a), the characteristics of typical daily load curves of the Sumatra and the Java–Bali electricity sectors (Batih and Sorapipatana, 2016; Syadli et al., 2014), and the long-term price elasticity of demand of Indonesian consumers (Burke and Kurniawati, 2018). The stylized load curves as well as the derived intercepts and slopes at each node are given in Appendix C. We assume here that the inverse demand functions that we derived tend to be a rather conservative estimate—the actual demand could therefore be higher. Still, we see our approach as a first starting point for further analysis in this area.

5 Results

In this section, we present the computational results of our evaluation, that is, for the Sumatra and Java–Bali electricity sectors. For a more detailed analysis and discussion of the results, see Section 6. We implemented the three pricing systems using the modeling language Zimpl (see Koch (2004)) and used SCIP 6.0.2 (see Gleixner et al. (2018)) to generate corresponding mps files. We then solved the problems with the CPLEX 12.10 solver (see IBM (2019)). Given the numerical results, we then calculated various key indicators for all three pricing systems. In particular, we computed (1) the welfare level and the consumer surplus, (2) private generation investments, (3) public network investments, (4) redispatch cost, and (5) resulting electricity prices; see Table 3 for an overview of the key indicators of the three models. For the zonal pricing system, we partitioned the 16 nodes into two price zones, in which nodes 1–9 belong to one price zone (hereinafter: "Sumatra") and nodes 10–16 belong to another price zone (hereinafter: "Java-Bali"). This partition reflects the two islands of Sumatra and Java–Bali (see Figure 3).

Table 3. Computational results for all three pricing systems; all values except for normalized welfare and electricity prices are rounded to full values. This table is the result of solving our multi-level optimization problems using standard software (ZIPML, SCIP, and CPLEX). Source: Authors' creation.

		Pricing System		
	Unit	Nodal	Zonal	Uniform
Normalized welfare	%	100	99.69	96.97
Absolute welfare	$	36,300,434	36,187,004	35,200,547
Consumer surplus	$	47,828042	47,833,489	47,857,683
Redispatch costs	$	-	749,138	2,254,933
Aggregated renewable capacity added	MW	43,784	43,630	47,479
Aggregated conventional capacity added	MW	349	0	0
Overall generation capacity added	MW	44,133	43,630	47,479
Aggregated network capacity added	MW	4,000	4,000	9,544
Number of lines added	-	4	4	10
Aggregated renewable investment	$	7,269,320	7,455,895	8,417,695
Aggregated conventional investment	$	45,956	0	0
Aggregated public network investment	$	288,000	288,000	687,168
Average electricity price	$/MWh	33.94	32.39	30.28
- for consumers in price zone "Sumatra"	$/MWh	32.41	30.28	30.28
- for consumers in price zone "Java–Bali"	$/MWh	35.91	35.12	30.28

First, we calculated the welfare levels realized under the three pricing systems (that is, we calculated the aggregated difference between the consumer surplus and all the costs of generation and investments). As nodal pricing is most efficient in terms of welfare, we normalized the realized welfare under the nodal pricing system to 100%. Our results illustrate that the overall welfare decreases when pooling nodes into one or more zones: under zonal and uniform pricing, the normalized welfare is 99.69% and 96.97%, respectively. However, when comparing the uniform with the zonal pricing system, our results illustrate that market splitting (i.e., introducing two price zones) increases welfare. In addition to the welfare levels, we computed the (gross) consumer surpluses under each pricing system (that is, we calculated the monetary benefits for consumers). Here, the order is the other way round, with uniform pricing yielding the highest and nodal pricing yielding the lowest consumer surplus.

Second, we computed the private investments in renewable and conventional generation. With respect to renewables, the uniform pricing system installs the maximum capacity of 47,479 MW. The nodal and the zonal pricing systems approximately realize 4,000 MW less renewables, with 43,784 MW and 43,630 MW, respectively. Conventional generators are only installed in the nodal pricing system—and on a much smaller scale than RES (i.e., 349 MW).

Third, we calculated the corresponding public network investments. Under the nodal and the zonal pricing systems, there are four transmission lines; under the uniform pricing system, there are 10 lines. Moreover, our results illustrate that, under all three pricing systems, transmission lines connect the two islands of Sumatra and Java–Bali. It is possible to explain the difference in the number of transmission lines under the three pricing systems by referring to the decision levels of the models: under the uniform pricing system, private firms consider the network as a "copperplate" (Weibelzahl, 2017), i.e., they cannot and/or do not take into account any network constraints, and do not receive location-specific investment signals. Accordingly, under the uniform pricing system, the TSO must adapt the network to the altered generation levels and invest in the appropriate lines to transport electricity to the respective consumers. The respective redispatch costs also reflect this.

Fourth, we compute the redispatch costs. Under uniform pricing, the redispatch costs are roughly three times higher than the redispatch costs under zonal pricing. Following a similar logic as for the number of constructed transmission lines, the higher redispatch costs that we observed under uniform pricing mainly result from private firms completely ignoring the network constraints when making their investment decisions. In contrast, while private firms do not consider intra-zonal network constraints, under zonal pricing they at least account for the inter-zonal network constraints. Therefore, in line with the literature (Ding and Fuller, 2005), the redispatch costs are lower under the zonal pricing system than under the uniform pricing system.

Fifth, we calculated the resulting electricity prices for the three pricing systems. On average (that is, over all nodes and time periods), consumers pay the lowest electricity price under the uniform pricing system, followed by the zonal pricing system. The highest average electricity price occurs under the nodal pricing system; see Section 6.2 for a more in-depth analysis and discussion of the resulting electricity prices.

6 Discussion and implications

6.1 Balancing Indonesia's energy trilemma

6.1.1 Energy sustainability

This horn of the energy trilemma emphasizes the impacts of all energy-related activities on the environment. Assuming that RES in general have a less damaging impact on the environment than conventional power plants, for example, through lower greenhouse gas (GHG) emissions, it would be preferable to choose the pricing system with (1) the most RES and/or (2) the fewest conventional power plants. Based on the results that we derived from our models and using the simplified representation of the Sumatra and Java–Bali electricity systems, this would be the uniform pricing system. Compared with the nodal and the zonal pricing systems, under the uniform pricing system, there is around 4,000 MW more RES capacity. In addition, no additional conventional capacity is installed. Comparing nodal with zonal pricing indicates that under the nodal pricing system 154 MW more RES are installed; however, under the nodal pricing system, also 349 MW of conventional capacity is installed, while no conventional capacity is installed under zonal pricing. Therefore, zonal pricing system would be the second-best option with respect to energy sustainability.

6.1.2 Energy security

This horn of the energy trilemma emphasizes that adequate generation capacity is available and that it is possible to transport the generated electricity reliably to the consumers. Our results indicate that all three pricing systems incentivize additional investments: as Section 5 described, each pricing system allows the addition of renewable generation capacities; under the nodal pricing system, also additional conventional generation capacities are installed. Furthermore, by the assumed regulation of the TSO under all three pricing systems the TSO invests in the network capacity to integrate the private investments in the best possible way into the overall system. However, as the private investments vary between the three pricing systems, the optimal network investments also depend on the respective market design. In particular, our results illustrate that, under nodal and zonal pricing, the TSO builds only four new lines, with an aggregated capacity of 4,000 MW, while under uniform pricing, it constructs 10 new lines, with an aggregated capacity of 9,544 MW. Ultimately, all three systems contribute to energy security in the sense that they add new capacities to the system. However, what distinguishes the zonal and uniform pricing systems from the nodal pricing system with respect to energy security is that redispatch is necessary under the latter two systems. Here, it is important to implement redispatch appropriately, as blackouts or brownouts may otherwise occur.

6.1.3 Energy equity

This horn of the energy trilemma emphasizes the affordability of energy, mainly from the perspective of consumers. Since the welfare levels of the three pricing systems are quite similar, two other indicators from our results allow us to draw conclusions regarding which pricing system seems to have advantages for this horn of the trilemma. First, comparing the electricity prices resulting under each pricing system reveals that the lowest average electricity price occurs under the uniform pricing system (i.e., 30.28 $/MWh), with the zonal (i.e., 32.39 $/MWh) and the nodal pricing systems (i.e., 33.94 $/MWh) in the second and third places, respectively. In addition, such a comparison of the resulting electricity prices highlights the regional variations that occur in the different pricing systems: Under the nodal pricing system, consumers in "Sumatra" in fact on average only pay 32.41 $/MWh, while consumers in "Java–Bali" on average pay 35.91 $/MWh; see Table C.6 in Appendix C for a detailed overview of the resulting electricity prices. This means that consumers in "Java–Bali" would have to pay 10.8% more than consumers in "Sumatra". Although such price spreads reflect the inherent logic of a nodal pricing system, it might be challenging to explain their necessity to consumers. As a consequence, consumers might perceive the differences in electricity prices to be unfair and acceptance problems may arise. A similar logic applies to zonal pricing where consumers in "Sumatra" only pay 30.28 $/MWh, while consumers in "Java-Bali" pay 35.12 $/MWh (i.e., roughly 16% more). Under the uniform pricing system, consumers pay the same electricity price across all regions. The experience from developing countries and regions such as Argentina, Brazil, Chile, Colombia, India, Peru, and Sub-Saharan Africa shows that policymakers have often faced public opposition when consumers considered price changes to be socially unfair – indicating a possible stumbling block with regard to successfully introducing a wholesale market for electricity (Kessides, 2012). Second, the consumer surplus—indicating the realized monetary benefits for consumers—is higher under the uniform pricing system than under the zonal pricing system. The nodal pricing system is the one that yields the lowest consumer surplus.

6.1.4 Recommendation for the uniform pricing system

Table 4 summarizes the above discussion of our results. It once again highlights that the uniform pricing system performs best with respect to both energy sustainability and energy equity, while performing at least as good as the other two systems with respect to energy security. Based on the results of our evaluation, we therefore recommend that Indonesia adopt a uniform pricing system in liberalizing its electricity market, as this system is likely to best balance the country's energy trilemma.

Table 4. Overview of the meaning of each horn of the energy trilemma, relevant indicators, and the most suitable pricing system (under the given parameters). Source: Authors' creation.

	Meaning	Relevant indicators	Appropriate pricing system
Energy sustainability	• Impact of all energy-related activities on the environment	• Aggregated renewable capacity added • Aggregated conventional capacity added	• Uniform pricing → The highest RES capacity is installed; no new conventional capacity is installed.
Energy security	• Availability of adequate generation capacity • Possibility to transport the generated electricity reliably to the consumers	• Overall generation capacity added • Aggregated network capacity added	• Nodal pricing • Zonal pricing • Uniform pricing → All three pricing systems incentivize investments in additional generation and network capacities.
Energy equity	• Affordability of energy, mainly from the perspective of consumers	• Average electricity price • Consumer surplus	• Uniform pricing → Consumers pay the lowest average electricity price; the consumer surplus is the highest.

Please note, however, that this recommendation is based solely on the results of our evaluation – and only holds under the given input parameters, the made assumptions, and metrics for the three horns of the energy trilemma. As described in Section 4, we only used data that was publicly available for our paper and we had to make several assumptions due to either lack of certain data or poor quality of existing data. Future research will have to show whether the uniform pricing system is still the most appropriate system with increased data quality. Moreover, the question of which pricing system is the most appropriate for Indonesia depends in particular on the weights policymakers wish to give to each horn of the energy trilemma. In this context, the Indonesian government would also have to consider additional factors, such as, e.g., the citizens' reaction to specific reforms, when weighing the three horns of the energy trilemma. Our recommendation for the uniform pricing system is based on the premise that Indonesia would like to focus more on the horn of energy sustainability in the future without neglecting the other two horns. With a different weighting of the three horns, as well as taking into account further factors not considered in our evaluation, one of the other two pricing systems could be considered as more desirable.

6.2 Transition pathway

In the following, we briefly outline a transition pathway through which Indonesia may introduce one of the three pricing systems. We build on Rotmans et al. (2001), who considered four phases of transition: (1) the pre-development phase, (2) the take-off phase, (3) the acceleration phase, and (4) the stabilization phase.

In the pre-development phase, a country is in a dynamic equilibrium in which the status quo does not visibly change. As Section 2.2 discussed in detail, Indonesia is in such a pre-development phase with respect to liberalizing its energy system. To progress to the take-off phase (i.e., the process of change commences because the state of the system begins to shift), the government and energy policymakers need to start the actual reform process. In our context, this means that policymakers take concrete steps to introduce a wholesale market for electricity. As with pricing systems, policymakers in Indonesia may learn from the experiences of other countries regarding the transition phases. For example, the experience from developing countries and regions shows that the order in which reforms are implemented is important. For example, the electricity sector should first be restructured and regulatory institutions established before it is privatized (Kessides, 2012).

In Germany, the transition to a wholesale market for electricity started with a reform of the Energy Industry Act (*Energiewirtschaftsgesetz, EnWG*) in 1998 (Agora Energiewende, 2019). Based on our discussions above, policymakers in Indonesia should first decide what their actual goal is with respect to achieving the three horns of the energy trilemma. Next, policymakers in Indonesia may choose the corresponding and appropriate electricity pricing system and implement it. As described in sub-section 6.1.4, this might be the uniform pricing system. In Germany – which has introduced a uniform pricing system – the reform of the EnWG was preceded by an energy directive of the European Union in 1996, which obliged its member states to break up monopolistic structures in their energy systems, with the goal of creating free, competitive, and effective markets on the one hand and maintaining a balance between the three horns of the energy trilemma on the other hand (Agora Energiewende, 2019). Exemplary steps that will be necessary during implementation in Indonesia comprise reducing the level of state control in the energy system, establishing a power exchange with corresponding permissions, and opening the market to independent and private parties.

In the acceleration phase (i.e., visible structural changes take place through an accumulation of socio-cultural, economic, ecological, and institutional changes that reflect each other), it will be important for policymakers to be oriented toward the set goals, for example, in the form of milestones with exact due dates. An exemplary milestone may relate to the question of when a power exchange starts its operation. In Germany, various laws that followed the 1998 reform of the EnWG regulated the unbundling of transmission and distribution system operators, third party market and network access, and the introduction of power exchanges. These laws were enacted over a period of about 15 years (Agora Energiewende, 2019). Experience in Germany therefore shows that the acceleration phase can take some time and policymakers in Indonesia may have to repeatedly correct/adjust the path of transition.

Finally, the stabilization phase is the phase in which Indonesia will successfully liberalize its energy system and adequately address the energy trilemma through the newly introduced market mechanisms. During all of these four phases, it is particularly important that those who are responsible for the reform as well as the future market participants acquire know-how on how a liberalized wholesale market for electricity functions and how they can organize it efficiently. Against this background, it will be essential to build actively on the experience that countries around the world have gained in introducing different pricing systems (see Section 2.1).

7 Conclusion

In this paper, we analyzed an electricity market reform concerning the introduction of a wholesale market for electricity with respect to balancing the energy trilemma in Indonesia. We developed three generic models that allow Indonesian policymakers to analyze the impact of introducing a nodal, a zonal, or a uniform pricing system on the three horns of the energy trilemma in their country. We evaluated our approach using a simplified network representation of the Indonesian electricity system with real-world data; in particular, we focused on the electricity systems of Sumatra and Java–Bali. The results of our evaluation indicate that, under the given input parameters of our simplified network representation, a uniform pricing system might help Indonesia balance its energy trilemma. Furthermore, our paper offered relevant implications for both research and practice. Our results indicate the need for a connection of the two islands of Sumatra and Java–Bali. Under each of the three pricing systems, it is possible to build corresponding transmission lines. According to our results, policymakers must, however, first consider which horn of the energy trilemma they want to focus on and then implement the appropriate electricity pricing system in the next step.

Moreover, we illustrated a transformation pathway that may guide (Indonesian) policymakers in introducing a wholesale market for electricity including one of the three pricing systems that we discussed in the paper.

Although our approach is in line with the current literature, there are inherent limitations that we want to outline briefly. First, the results of our evaluation are limited to the electricity networks of Sumatra and Java–Bali, while the general applicability of our developed models holds for any other country or region. This implies, for example, that our models are generally applicable to Indonesian regions other than Sumatra and Java-Bali; the evaluation of the results, however, must always be oriented towards the specific characteristics of each electricity system. Second, due to a lack of some real-world data, the data that our evaluation uses contain several assumptions, for example, regarding exact network capacities. Third, our models are limited with respect to further policy instruments like network fees, which they do not consider. Furthermore, we note that developing Indonesia's current single-buyer model to a wholesale market model may entail practical challenges that we did not consider in our paper, for example, Indonesia's political economy.

Future research may therefore focus, for example, on the integration of storage into our model, which may be of relevance with respect to energy security. Moreover, research may extend our model by considering the concept of demand-side flexibility and its possible effects on electricity price peaks. Future research may also enhance our data set and extend the evaluation to all the regions of Indonesia. Finally, future research may investigate whether combinations of the three pricing systems could contribute to a better balance of the three horns of the energy trilemma. In summary, the models that we developed in this paper provide a manifold foundation for research and practice regarding the analysis of impacts concerning the introduction of a wholesale market for electricity in Indonesia. Our evaluation results and respective discussions may serve as a valuable basis for policymakers regarding the necessary implementation of electricity market reforms and the successful transition to a low-carbon economy.

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Appendix A. Formal models of the nodal, zonal, and uniform pricing systems

A.1 Decision levels and basic model set-up

In the following, we present the formal models for the three different pricing systems; see also Grimm et al. (2016) and Weibelzahl and Märtz (2020) for similar models. In particular, we will present step by step the decision levels (hereinafter levels) under each of the pricing systems according to Figure 1 in Section 2.1. From a mathematical point of view, our models represent multilevel optimization problems, in which the different players anticipate the optimal decisions that the other players take on subsequent levels: for example, the TSO chooses the optimal line investments on the first level, forming expectations of the optimal private generation investments, spot market outcomes, and necessary redispatch interventions on the subsequent levels. On the other hand, the lower-level decisions relating to private generation investments, spot market outcomes, and redispatch depend on the public line investments that occur on the first level. This method is an established standard in the literature for modelling the three pricing systems (Grimm et al., 2016; Weibelzahl and Märtz, 2020, 2018).

The formulation of the public network investments of the TSO, that is, decision level 1 (see Section A.2), is identical for all three of the pricing systems. As decision level 2, that is, expected private generation investments and spot market trade, as well as decision level 3, that is, necessary redispatch of the TSO, differ for each of the three systems, we model these levels in system-specific Sections A.3, A.4, and A.5.

A.2 Public network investments of the TSO (decision level 1)

On the first level and for all three pricing systems, we assume a benevolent TSO (or equivalently a TSO that is regulated accordingly) that chooses a network expansion plan that maximizes the welfare of the whole system:

$$\begin{aligned} \max \sum_{c\in C}\sum_{t\in T}\int_0^{d_{c,t}} \pi_{c,t}(h)\,\mathrm{d}h - \sum_{r\in R}\sum_{t\in T} v_r x_{r,t} - \sum_{g\in G}\sum_{t\in T} v_g y_{g,t} - \sum_{g\in R^{\text{new}}} i_r \bar{x}_r^{\text{new}} \\ - \sum_{g\in G^{\text{new}}} i_g \bar{y}_g^{\text{new}} - \sum_{l\in L^{\text{new}}} i_l w_l \end{aligned} \tag{A.1}$$

The TSO accounts for the integrality of its network-investment decisions and expects optimal private generation investments as well as spot market (and redispatch) outcomes of the subsequent levels (see also the following sections).

$$w_l \in \{0,1\} \quad \forall l \in L^{\text{new}}. \tag{A.2}$$

A.3 Nodal pricing: decision level 2

In this subsection, we model the investment and spot market bidding of perfectly competitive companies for a nodal pricing system. The assumption of perfect competition (with corresponding monitoring of market power) in electricity markets established as a standard in the economic literature, e.g., Boucher and Smeers (2001), Daxhelet and Smeers (2007), Grimm et al. (2016), and Weibelzahl (2017), and may serve as a starting point for future analysis of possible imperfect competition of many small, non-interconnected islands such as in Indonesia. The assumption of perfect competition means that neither generators nor consumers can affect prices through strategic behavior; it also implies that no strategic product differentiation takes place. Perfect competition also allows us to formulate investment and market clearing as a single welfare maximization problem given the above network investments of the TSO (Grimm et al., 2016) and therefore keeps our model computationally tractable:

$$\max \sum_{c\in C}\sum_{t\in T}\int_0^{d_{c,t}} \pi_{c,t}(h)\mathrm{d}h - \sum_{r\in R}\sum_{t\in T} v_r x_{r,t} - \sum_{g\in G}\sum_{t\in T} v_g y_{g,t} - \sum_{g\in R^{\text{new}}} i_r \bar{x}_r^{\text{new}} - \sum_{g\in G^{\text{new}}} i_g \bar{y}_g^{\text{new}} \tag{A.3}$$

We first require a nodal flow balance according to

$$d_{n,t} = \sum_{r\in R_n} x_{r,t} + \sum_{g\in G_n} y_{g,t} + \sum_{l\in\delta_n^{\text{in}}(L)} f_{l,t} - \sum_{l\in\delta_n^{\text{out}}(L)} f_{l,t} \quad \forall n\in N, t\in T, \tag{A.4}$$

where $\delta_n^{\text{in}}(L)$ and $\delta_n^{\text{out}}(L)$ collect all the ingoing and outgoing lines of node n, respectively.

In addition, all the power flows must account for their lower and upper flow bounds:

$$-\bar{f}_l \le f_{l,t} \le \bar{f}_l \quad \forall l\in L^{\text{ex}}, t\in T, \tag{A.5}$$

$$-\bar{f}_l w_l \le f_{l,t} \le \bar{f}_l w_l \quad \forall l\in L^{\text{new}}, t\in T. \tag{A.6}$$

According to Kirchhoff's Laws, the following determines the power flows on the different transmission lines:

$$f_{l,t} = B_l(\theta_{n,t} - \theta_{m,t}) \quad \forall l=(n,m)\in L^{\text{ex}}, t\in T, \tag{A.7}$$

$$-M(1-w_l) \le f_{l,t} - B_l(\theta_{n,t} - \theta_{m,t}) \le M(1-w_l) \quad \forall l=(n,m)\in L^{\text{new}}, t\in T. \tag{A.8}$$

In the above constraints, $\theta_{n,t}$ gives the phase angle at node n in time period t. In addition, parameter M is a sufficiently large constant that we denote as “big-M”.

The phase angle of reference node 1 is set to zero, ensuring unique phase angle values in the electricity network:

$$\theta_{1,t} = 0 \quad \forall t\in T. \tag{A.9}$$

The power generation is limited according to:

$$0 \le x_{r,t} \le \alpha_{r,t}\tau\bar{x}_r^{\text{ex}} \quad \forall r\in R^{\text{ex}}, t\in T, \tag{A.10}$$

$$0 \le x_{r,t} \le \alpha_{r,t}\tau\bar{x}_r^{\text{new}} \quad \forall r\in R^{\text{new}}, t\in T, \tag{A.11}$$

$$0 \le y_{g,t} \le \tau\bar{y}_g^{\text{ex}} \quad \forall g\in G^{\text{ex}}, t\in T, \tag{A.12}$$

$$0 \le y_{g,t} \le \tau\bar{y}_g^{\text{new}} \quad \forall g\in G^{\text{new}}, t\in T \tag{A.13}$$

Note that, since generation capacity is denoted in MW while actual generation is given in MWh, we multiply the right-hand sides of equations (A.10) to (A.13) with the time step τ.

Finally, all the investment variables $\bar{x}_r^{\text{new}}$, $\bar{y}_g^{\text{new}}$ must be non-negative:

$$\bar{x}_r^{\text{new}} \geq 0 \qquad \forall r \in R^{\text{new}}, \tag{A.14}$$
$$\bar{y}_g^{\text{new}} \geq 0 \qquad \forall g \in G^{\text{new}}. \tag{A.15}$$

A.4 Zonal pricing: decision level 2 and 3

Spot market trade and private investments in new generation capacities. In the case of zonal pricing, we partition the node set N into k connected, non-empty, and given price zones $Z_1, \dots, Z_k$. $\mathcal{Z} = \{1, \dots, k\}$ gives the set of price zone indices, , for which the responsible public entities, for example regulators, governments, or TSOs, specify k ex-ante. In the following, we assume transfer capacity-based market coupling, that is, we use only restrictions relating to the available transfer capacities (i.e., the given $\bar{f}_l$ for all inter-zonal line) between zones. The zone-specific prices do not account for possible intra-zonal network congestion, but companies exclusively receive price signals incentivizing them not to exceed the inter-zonal transmission capacities $\bar{f}_l$. For the ease of notation, we let L^{inter} be the set of all inter-zone transmission lines. As under nodal pricing, we model the optimal investment behavior and market clearing as a single welfare maximization problem; that is, we again refer to Equation (A.3).

In contrast to nodal flow balance, we only require zonal flow balance:

$$\sum_{n \in Z_i} d_{n,t} = \sum_{n \in Z_i} \left(\sum_{r \in R_n} x_{r,t} + \sum_{g \in G_n} y_{g,t} + \sum_{l \in \delta_{Z_i}^{\text{in}}(L)} f_{l,t} - \sum_{l \in \delta_{Z_i}^{\text{out}}(L)} f_{l,t} \right) \quad \forall i \in \mathcal{Z}, t \in T. \tag{A.16}$$

The following restrict the power flows on inter-zonal transmission lines:

$$-\bar{f}_l \leq f_{l,t} \leq \bar{f}_l \qquad \forall l \in L^{\text{ex}} \cap L^{\text{inter}}, t \in T, \tag{A.17}$$
$$-\bar{f}_l w_l \leq f_{l,t} \leq \bar{f}_l w_l \qquad \forall l \in L^{\text{new}} \cap L^{\text{inter}}, t \in T. \tag{A.18}$$

As under nodal pricing, power generation must be technically feasible; that is, we again refer to Equations (A.10) to (A.13).

Finally, as with nodal pricing, all the investment variables must be nonnegative:

$$\bar{x}_r^{\text{new}} \geq 0 \qquad \forall r \in R^{\text{new}}, \tag{A.19}$$
$$\bar{y}_g^{\text{new}} \geq 0 \qquad \forall g \in G^{\text{new}}. \tag{A.20}$$

Redispatch. On the redispatch level, the TSO redispatches the contracted spot market volumes (i.e., generation, demand, and inter-zonal power flow variables), restoring the feasibility of power flows while minimizing the arising redispatch costs. The final quantities after redispatch may be smaller than, equal to, or larger than the pre-redispatch quantities, that is, the contracted spot market quantities. Throughout the paper, we indicate redispatch adjustments with Δ; for example, $\Delta y_{1,2} = 5$ indicates that the TSO asks conventional power generator 1 to increase its generation by 5 units in period 2. In the following, we will use a cost-based redispatch mechanism that is, for instance, in use in Germany. Under such mechanism, redispatch is profit neutral and only accounts for additional or saved costs associated with a redispatch intervention to avoid gaming problems or market power abuse. In other words, the TSO pays an upregulated power plant its additional variable costs, while a downregulated power plans pays the TSO its saved variable cost, which does not change the spot market profits of the company. We can therefore state the redispatch cost minimization of the TSO for given spot market outcomes as

$$\min \sum_{t \in T} \left(\sum_{c \in C} \int_{d_{c,t}+\Delta d_{c,t}}^{d_{c,t}} \pi_{c,t}(h) \mathrm{d}h + \sum_{r \in R} v_r \Delta x_{r,t} + \sum_{g \in G} v_g \Delta y_{g,t} \right), \tag{A.21}$$

where we explicitly assume that redispatch can apply to both producers and consumers.

Similar to the above nodal pricing formulation, power balance is imposed for each node on the redispatch level:

$$\begin{aligned} d_{n,t} + \Delta d_{n,t} = \sum_{r \in R_n} (x_{r,t} + \Delta x_{r,t}) + \sum_{g \in G_n} (y_{g,t} + \Delta y_{g,t}) \\ + \sum_{l \in \delta_n^{\mathrm{in}}(L)} (f_{l,t} + \Delta f_{l,t}) - \sum_{l \in \delta_n^{\mathrm{out}}(L)} (f_{l,t} + \Delta f_{l,t}) \end{aligned} \qquad \forall n \in N, t \in T. \tag{A.22}$$

After redispatch, all the power flows must be physically feasible:

$$-\bar{f}_l \le f_{l,t} + \Delta f_{l,t} \le \bar{f}_l \qquad \forall l \in L^{\mathrm{ex}}, t \in T, \tag{A.23}$$

$$-\bar{f}_l w_l \le f_{l,t} + \Delta f_{l,t} \le \bar{f}_l w_l \qquad \forall l \in L^{\mathrm{new}}, t \in T, \tag{A.24}$$

$$f_{l,t} + \Delta f_{l,t} = B_l(\theta_{n,t} - \theta_{m,t}) \qquad \forall l = (n,m) \in L^{\mathrm{ex}}, t \in T, \tag{A.25}$$

$$\begin{aligned} -M(1-w_l) \le f_{l,t} + \Delta f_{l,t} - B_l(\theta_{n,t} - \theta_{m,t}) \\ \le M(1-w_l) \end{aligned} \qquad \forall l = (n,m) \in L^{\mathrm{new}}, t \in T, \tag{A.26}$$

$$\theta_{1,t} = 0 \qquad \forall t \in T. \tag{A.27}$$

Finally, when choosing the optimal redispatch, the TSO must take both the private generation investments and the exogenous weather conditions into account:

$$0 \le x_{r,t} + \Delta x_{r,t} \le \alpha_{r,t} \tau \bar{x}_r^{\mathrm{ex}} \qquad \forall r \in R^{\mathrm{ex}}, t \in T, \tag{A.28}$$

$$0 \le x_{r,t} + \Delta x_{r,t} \le \alpha_{r,t} \tau \bar{x}_r^{\mathrm{new}} \qquad \forall r \in R^{\mathrm{new}}, t \in T, \tag{A.29}$$

$$0 \le y_{g,t} + \Delta y_{g,t} \le \tau \bar{y}_g^{\mathrm{ex}} \qquad \forall g \in G^{\mathrm{ex}}, t \in T, \tag{A.30}$$

$$0 \le y_{g,t} + \Delta y_{g,t} \le \tau \bar{y}_g^{\mathrm{new}} \qquad \forall g \in G^{\mathrm{new}}, t \in T. \tag{A.31}$$

A.5 Uniform pricing: decision levels 2 and 3

Spot market trade and private investments in new generation capacities. It is possible to view uniform pricing as a special case of the above zonal pricing model in which we only have a single price zone, that is, $k = 1$. As a direct consequence, we have the same model as in Section A.4, where zonal balance takes the form of a single market-clearing constraint for the whole market:

$$\sum_{n \in N} d_{n,t} = \sum_{r \in R} x_{r,t} + \sum_{g \in G} y_{g,t} \qquad \forall t \in T. \tag{A.32}$$

Redispatch. Similar to the case of zonal pricing, uniform pricing will also in general require redispatch to ensure transmission feasibility. Such redispatch can be modelled in the same way as in Section A.4.

Appendix B. Sets, parameters, and variables

This appendix presents a summary of the main sets, parameters, and variables that we used in our models.

Table B.1. Sets. Source: Authors' creation.

Symbol	Description
$\mathcal{G}$	Electricity network
N	Set of network nodes
$C \subseteq N$	Set of consumer nodes
L	Set of transmission lines
$L^{\mathrm{ex}} \subseteq L$	Set of existing transmission lines
$L^{\mathrm{new}} \subseteq L$	Set of candidate transmission lines
T	Set of time periods
Z	Set of given price zones
G	Set of conventional generators
$G_n \subseteq G$	Set of conventional generators located at node n
$G^{\mathrm{ex}} \subseteq G$	Set of existing conventional generators
$G^{\mathrm{new}} \subseteq G$	Set of new conventional generators
R	Set of renewable generators
$R_n \subseteq R$	Set of renewable generators located at node n
$R^{\mathrm{ex}} \subseteq R$	Set of existing renewable generators
$R^{\mathrm{new}} \subseteq R$	Set of new renewable generators

Table B.2. Parameters. Source: Authors' creation.

Symbol	Description	Unit
$a_{c,t}$	Intercept of inverse demand function c in period t	\$/MWh
b_c	Slope of inverse demand function c	\$/MWh²
v_g	Variable production cost of generator g	\$/MWh
v_r	Variable production cost of generator r	\$/MWh
$\bar{x}_r^{ex}$	Maximum power output of existing generator r	MW
$\bar{y}_g^{ex}$	Maximum power output of existing generator g	MW
$\bar{f}_l$	Transmission capacity of line l	MWh
B_l	Susceptance of line l	MWh
i_l	Line investment cost for $l \in L^{new}$	\$
k	Number of price zones	1
i_g	Generation investment cost for g	\$/MW
i_r	Generation investment cost for r	\$/MW

Table B.3. Variables and derived quantities. Source: Authors' creation.

Symbol	Description	Unit
$d_{c,t}$	Electricity demand at node c in period t	MWh
$x_{r,t}$	Electricity generation of generator r in period t	MWh
$y_{g,t}$	Electricity generation of generator g in period t	MWh
$\bar{x}_r^{new}$	Invested generation capacity of candidate renewable generator r	MW
$\bar{y}_g^{new}$	Invested generation capacity of candidate conventional generator g	MW
$f_{l,t}$	Power flow on line l in period t	MWh
$\Theta_{n,t}$	Phase angle value at node n in period t	rad
w_l	Line extension variable for candidate line $l \in L^{new}$	{0, 1}

Appendix C. Data description and detailed results

In this appendix, we present more detailed information on the model inputs that we used.

Table C.1. Overview of nodes (provinces of Sumatra and Java–Bali) of the considered network. Source: Authors' creation.

Name	ID
Sumatra	
Aceh	1
North Sumatra	2
Riau (incl. Riau Islands)	3
West Sumatra	4
Jambi	5
Bengkulu	6
South Sumatra	7
Bangka Belitung	8
Lampung	9
Java	
Jakarta	10
Banten	11
West Java	12
Central Java	13
Yogyakarta	14
East Java	15
Lesser Sunda Islands	
Bali	16

Table C.2. Overview of existing generation capacities (MW). Source: Authors' creation based on PT PLN (2018).

ID	Coal	Gas	Diesel	Hydro	Geothermal	Wind	Solar PV	Biomass	Total
1	220	380	96.2	-	-	-	-	-	696.2
2	800	1,286.4	270.6	520.9	350	-	-	-	3,227.9
3	249	432.2	420.58	114	-	-	-	0.9	1,216.68
4	406.5	-	63.09	286.5	-	-	-	-	756.09
5	12	359.2	10.4	-	-	-	-	-	381.6
6	-	-	41.7	236.3	-	-	-	-	278
7	1,277	863.9	25	23.7	-	-	-	-	2,189.6
8	93	75	126.5	-	-	-	-	11	305.5
9	454	160	0.4	174.3	210				998.7
10	-	3,539	-	-	-	-	-	-	3,539
11	6,201.3	740	-	-	-	-	-	-	6,941.3
12	2,700	2,452	-	1,985.5	1,198.7	-	-	-	8,336.2
13	5,390	-	1,396.4	305.7	60	-	-	-	7,152.1
14	-	-	-	-	-	-	-	-	-
15	6,070	3,004.6	124.88	274.9	-	-	-	-	9,474.38
16	426	-	-	-	-	0.75	0.03	-	426.78
Total	24,298.8	13,292.3	2,575.75	3,685.3	1,818.7	0.75	0.03	11.9	

Figure C.1. Stylized load curve of the Sumatra electricity system. Source: Authors' creation based on Syadli et al. (2014).

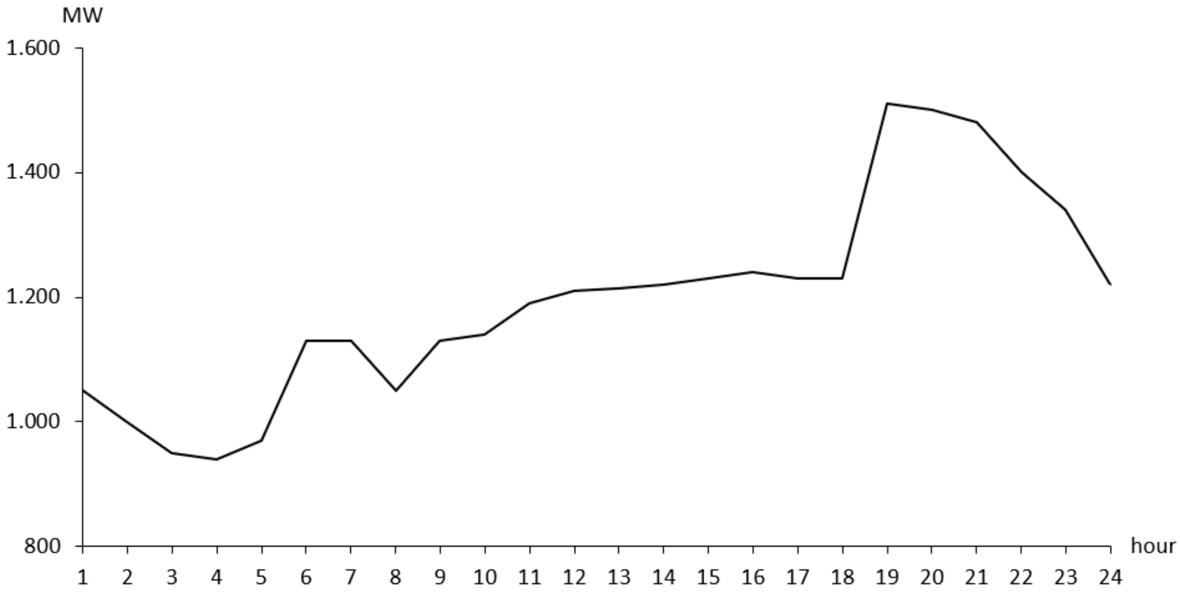

Figure C.2. Stylized load curve of the Java-Bali electricity system. Source: Authors' creation based on Batih and Sorapipatana (2016).

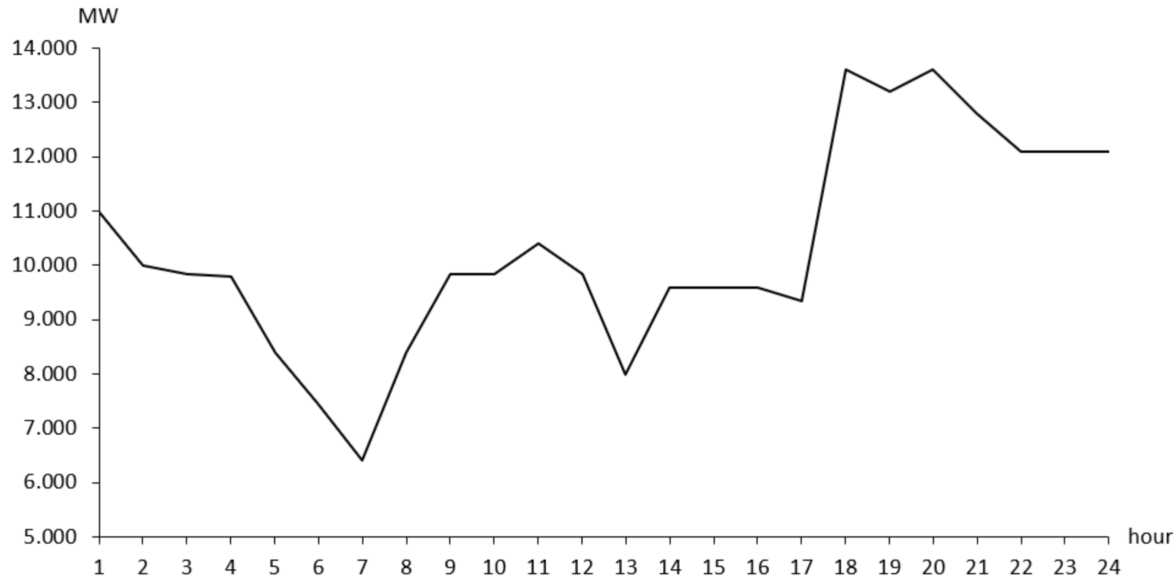

Table C.4. Derived intercepts at each node and time period. Source: Authors' creation.

	ID															
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Time period																
1	148.26	184.06	175.44	169.05	267.95	234.60	162.62	82.03	163.98	216.40	171.80	152.71	138.47	230.11	158.81	178.70
2	143.45	178.09	169.75	163.57	259.26	226.99	157.35	79.37	158.66	203.23	161.35	143.42	130.05	216.11	149.15	167.83
3	138.64	172.12	164.06	158.09	250.58	219.39	152.07	76.71	153.35	201.26	159.79	142.03	128.79	214.01	147.70	166.20
4	137.68	170.93	162.93	156.99	248.84	217.87	151.02	76.18	152.28	200.60	159.26	141.57	128.37	213.31	147.21	165.66
5	140.57	174.51	166.34	160.28	254.05	222.43	154.18	77.78	155.47	182.17	144.63	128.56	116.57	193.72	133.69	150.44
6	155.95	193.61	184.54	177.82	281.85	246.77	171.06	86.29	172.49	169.67	134.71	119.74	108.57	180.42	124.51	140.11
7	155.95	193.61	184.54	177.82	281.85	246.77	171.06	86.29	172.49	155.85	123.73	109.98	99.73	165.72	114.37	128.70
8	148.26	184.06	175.44	169.05	267.95	234.60	162.62	82.03	163.98	182.17	144.63	128.56	116.57	193.72	133.69	150.44
9	155.95	193.61	184.54	177.82	281.85	246.77	171.06	86.29	172.49	201.26	159.79	142.03	128.79	214.01	147.70	166.20
10	156.91	194.80	185.68	178.92	283.59	248.29	172.11	86.82	173.55	201.26	159.79	142.03	128.79	214.01	147.70	166.20
11	161.72	200.77	191.37	184.40	292.28	255.90	177.38	89.48	178.87	208.50	165.53	147.14	133.42	221.71	153.01	172.18
12	163.64	203.16	193.65	186.59	295.76	258.94	179.49	90.54	181.00	201.26	159.79	142.03	128.79	214.01	147.70	166.20
13	164.12	203.76	194.21	187.14	296.62	259.70	180.02	90.81	181.53	176.91	140.45	124.85	113.20	188.12	129.83	146.09
14	164.60	204.35	194.78	187.69	297.49	260.46	180.55	91.08	182.06	197.97	157.17	139.71	126.68	210.52	145.28	163.48
15	165.57	205.55	195.92	188.79	299.23	261.99	181.60	91.61	183.12	197.97	157.17	139.71	126.68	210.52	145.28	163.48
16	166.53	206.74	197.06	189.88	300.97	263.51	182.66	92.14	184.19	197.97	157.17	139.71	126.68	210.52	145.28	163.48
17	165.57	205.55	195.92	188.79	299.23	261.99	181.60	91.61	183.12	194.68	154.56	137.39	124.58	207.02	142.87	160.76
18	165.57	205.55	195.92	188.79	299.23	261.99	181.60	91.61	183.12	250.62	198.98	176.86	160.37	266.50	183.92	206.96
19	192.49	238.97	227.78	219.48	347.89	304.59	211.13	106.50	212.90	245.36	194.79	173.15	157.00	260.90	180.06	202.61
20	191.53	237.78	226.64	218.39	346.15	303.06	210.08	105.97	211.84	250.62	198.98	176.86	160.37	266.50	183.92	206.96
21	189.60	235.39	224.36	216.20	342.67	300.02	207.97	104.91	209.71	240.09	190.61	169.43	153.64	255.31	176.19	198.27
22	181.91	225.84	215.26	207.43	328.77	287.85	199.53	100.65	201.20	230.88	183.30	162.93	147.74	245.51	169.43	190.66
23	176.14	218.68	208.44	200.85	318.35	278.72	193.20	97.46	194.82	230.88	183.30	162.93	147.74	245.51	169.43	190.66
24	164.60	204.35	194.78	187.69	297.49	260.46	180.55	91.08	182.06	230.88	183.30	162.93	147.74	245.51	169.43	190.66

Table C.5. Derived slope parameters at each node. Source: Authors' creation.

ID	slope
1	0.335
2	0.128
3	0.202
4	0.374
5	0.910
6	1.513
7	0.222
8	0.501
9	0.273
10	0.042
11	0.112
12	0.033
13	0.049
14	0.489
15	0.043
16	0.194

Table C.6. Average electricity prices ($/MWh) for consumers, depending on the pricing system. Source: Authors' creation.

	Pricing System		
Node	Nodal	Zonal	Uniform
1	30.28	30.28	30.28
2	30.28	30.28	30.28
3	30.28	30.28	30.28
4	30.28	30.28	30.28
5	31.03	30.28	30.28
6	29.52	30.28	30.28
7	31.78	30.28	30.28
8	46.48	30.28	30.28
9	31.78	30.28	30.28
"Sumatra"	32.41	30.28	30.28
10	36.10	35.12	30.28
11	36.42	35.12	30.28
12	35.77	35.12	30.28
13	35.77	35.12	30.28
14	35.77	35.12	30.28
15	35.77	35.12	30.28
16	35.77	35.12	30.28
"Java–Bali"	35.91	35.12	30.28

How Different Electricity Pricing Systems Affect the Energy Trilemma: Assessing Indonesia's Electricity Market Transition

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Abstract:

~~A major impediment to higher renewable energy sources (RES) penetration often lies in the historically grown structures of a country's electricity sector. In Indonesia, policymakers have relied on cheap fossil fuels and state control to provide the population with access to both reliable and affordable electricity in the past decades. However, this focus on only two of the three horns of the energy trilemma, namely, energy security and energy equity (and not sustainability), may put Indonesia at risk of missing its ambitious RES targets. While a number of small-scale reforms attempts to promote RES integration in Indonesia have proved to be relatively unsuccessful in recent years, this paper proposes a large-scale reform, namely, introducing a wholesale electricity market.~~ Indonesia's current energy policy, which relies on cheap fossil fuels and focus~~ing~~es on two out of the three horns of the energy trilemma, namely, energy security and energy equity, may impede its efforts to higher shares of renewable energy sources. This paper develops three generic models that allow policymakers to analyze the impact of introducing a wholesale electricity market managed under either a nodal, a zonal, or a uniform pricing system on the three horns of the energy trilemma. It evaluates the models using a simplified network representation of the Indonesian electricity sector. The results indicate that~~,~~ under the model assumptions made and ~~and the~~ given the used input parameters as well as the used metrics for the three horns of the energy trilemma, a uniform pricing system might help Indonesia to balance its energy trilemma. ~~Considering that any major reform intended to improve energy sustainability in Indonesia will only be a success if it also addresses energy security and energy equity, the paper also discusses the results from the perspective of energy justice and the need to balance the country's energy trilemma.~~

JEL Classification: Q400, Q410, Q420, Q480, L510, L110

Keywords: Electricity Pricing System; Electricity Market Liberalization; Energy Trilemma; Indonesia; ~~Energy Justice;~~ Renewable Energy Sources.