Natural Gas Market Rigidities and the Promotion of NC-RER in Peru

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Abstract[1]

In recent years Peru has launched a program to promote non-conventional renewable energetic resources (NC-RER) in the electric generation market. Despite relative initial success in attracting investments to this new technology, future regulatory adjustments are needed to mitigate acknowledged risks associated with NC-RER such as volatility and intermittent production. In the Peruvian case, the regulatory approach to be applied is closely related to the natural gas (NG) market's performance, which displays high levels of rigidities, particularly for power generators. The main inflexibility in the natural gas market is transport contract conditions, forcing gas-fired power generators to contract all their capacity in firm transport service. Based on a model optimization for the electricity system in Peru, this paper finds that inflexibilities in the natural gas market are costly compared to an optimal system. Additionally, as the share of non-conventional renewable energies increases, so does the cost of the system in greater proportion in an inflexible natural gas market in compared to a flexible one.

JEL classifications: L94, L95, L98, L51, Q41, C61
Keywords: Integrated gas and electricity networks, Gas flexibility, Distortions in the natural gas market, Intermittent renewable resources, Renewable resources promotion, Energy policy, Electricity industry

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1. Introduction

In 2010 the Peruvian Government launched a program to promote the production of non-conventional renewable energetic resources (NC-RER) in the electric generation market. The scheme selected by policymakers introduced competitive auctions where projects were awarded with supply contracts that guaranteed a certain level of revenues. Auctions allow the policymaker to set the NC-RER capacity that will be incorporated into the system. However, the awarded NC-RER supply contracts exhibited sharp differences compared to market conditions that other technologies face. Moreover, since a minimum quota of 5 percent in energy production for NC-RER technologies was already reached in 2019, policymakers will have to decide how to increase penetration efficiently on a subsidy-free basis and how to design the regulatory framework for these technologies. Of particular importance is the intermittence of NC-RER supply, which represents one of its main operative and economic difficulties. Who will be paid for intermittence, for example, and on what basis? Furthermore, what back-up technology or technologies will be used?

Peru is a country with vast natural gas reserves, which allowed almost 45 percent of electricity demand to be supplied by this fuel. However, the rules created for the promotion and development of the natural gas market, based on Camisea Project infrastructure, have led the power generation industry to bear a significant financial burden in recent years, exposing them to market design flaws in the oversupply environment. As the regulatory framework and contractual terms with which NG-fired power generation plants must comply are demanding and rigid, companies face significant difficulties in adapting to cyclical market conditions and the seasonality of gas demand by the electricity market.

This document finds that the flexibilization of the NG market would allow increasing NC-RER supply at a lower operation cost since the NG costs of back-up NG-fired power plants would have more variable commercial conditions compared to the current scenario. We tested a model that optimizes the structure of the power generation matrix and found that, compared to the current regulatory scenario, increasing the share of NC-RER from 5 percent to 10 percent would be 17 percent cheaper in terms of the system cost if the rigid conditions in the NG-market changed to a more flexible scenario.

The document is organized as follows. In the next section we review the mechanisms used internationally to promote NC-RER, the current promotion scheme of NC-RER in Peru and its main outcomes. In Section 3, we discuss and analyze the main rigidities that power generation faces in its NG supply in Peru regarding regulations and contracts. The fourth section examines rigidities in both NC-RER and NG markets, and it discusses lessons and regulatory alternatives. In Section 5, we apply a simplified methodology to estimate the impact of NG market flexibilization in the operation cost of the electricity sector for alternative scenarios of NC-RER quotas. Finally, we present the main conclusions and policy recommendations.

2. The Promotion of NC-RER in Peru

2.1 NC-RER Promotion in the World

Non-conventional renewable energetic resources (NC-RER) are technologies that use primary energy resources, mainly solar and wind, to produce electricity. The widespread implementation of these technologies is currently depicted as a tool to decrease greenhouse gas emissions and avoid global warming. Moreover, the literature remarks on various positive effects such as a more diversified energy matrix, security of supply and positive impact on local labor (Schmalensee, 2011).

Even though there have been significant technological improvements in terms of costs and efficiency, the introduction of NC-RER technologies is still subject to high uncertainty levels. The volatile nature of NC-RER—i.e., their intermittence—is a relevant issue for the operational and economic stability of electric market. According to Joskow (2011) and Borenstein (2012), the evaluation of costs and benefits of NC-RER requires the development of sophisticated economic and engineering models, the only way to design appropriate and sustainable policies to promote NC-RER.

A recent study by Delarue and Dirk Van Hertem (2016) identified the costs associated with RER technologies through a classification of their main characteristics: variability, limited predictability and specific location. Considering all these specificities, there are four related costs for RER technologies: back-up cost, balancing cost, grid integration cost and subsidy cost.

Back-up costs are related to two notions: fixed and operational costs. The first refers to the additional capacity required to generate electricity at times of low RER generation, and the second, to the shift along with load generation. Balancing costs are related to the limited predictability of RER. This cost is associated with the security of the natural gas system, in the sense that additional operational reserves should be maintained to ensure that outages can be addressed. As NC-RER can be location-specific or modular, it is highly probable that such generation plants will need to be integrated into the grid, resulting in grid integration costs. Three grid expansions or reinforcements might be considered at the transmission level: dedicated transmission grid for RER technologies, additional cross-border interconnections and reinforcement of the current domestic grid. As part of integration costs, subsidy costs arise as compensation of private cost.

At the international level, different evolutionary mechanisms of promotion for NC-RER can be identified. For example, sales of greenhouse gas reduction certificates allow for additional revenues for NC-RER plants. Certificates markets have shown recently important improvements. However, they are still insufficient to sustain adequate NC-RER investment. A second mechanism establishing quotas for NC-RER technologies to supply a system's demand (renewable portfolio standard, RPS).

A third mechanism is applying a Feed-in Tariff (FIT), which fixes a price cap for NC-RER investments. According to Schmalensse (2011), the FIT mechanism is more popular than RPS, mainly used in the United States, since it involves lower risk for investors. However, removing risks from investors could mean that risks are transferred to other agents of the market. Furthermore, FIT does not always minimize the cost of meeting NC-RER promotion goals. For example, the case of Spain, where the FIT scheme was applied, shows that excessive solar and wind investment leads to greater growth in capacity than expected (Clerc et al., 2018)

A fourth mechanism used by countries such as Peru consists of assigning quotas in energy supply that are not met through contracts with distribution companies. NC-RER supply the system directly through the spot market, and compensation is established to secure minimum revenues for projects.

2.2 The Case of Peru

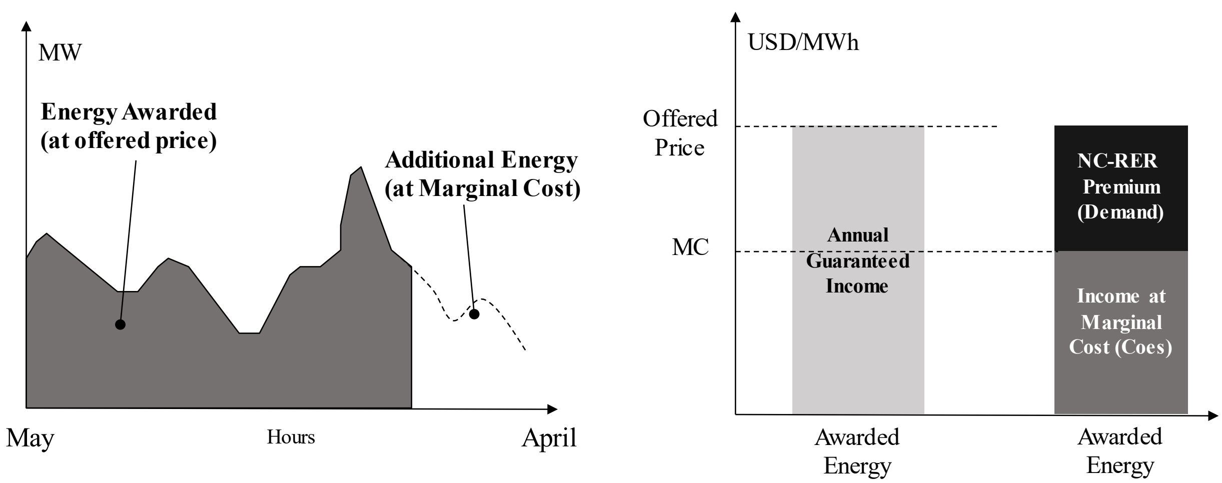
In Peru, the development of non-conventional renewable energy resources for electricity generation (hereinafter NC-RER) had its starting point in 2008, with the approval of Law Decree N° 1002, which alongside its regulation (Supreme Decree N° 012-2011-EM), established:

- The development of NC-RER is a matter of national interest.
- A target of a 5 percent share for NC-RER (excluding mini-hydro) in energy consumption, to be reviewed every five years.

- Osinergmin, the energy regulator, will open auctions for new projects to fulfill energy requirements established by the Ministry of Energy and Mines (MEM).
- The necessity of auctions will be evaluated by MEM at least every two years.
- NC-RER technologies will be given priority in the dispatch order.

The annual income of NC-RER plants awarded in auctions consists of the following: the company sells all its energy to the spot market. However, NC-RER plants have two income sources: the awarded amount of energy valued at the awarded tariff ("awarded income") and the energy production above the awarded energy valued at the system's marginal cost. If the difference between the "awarded income" and spot market income is negative, the losses are compensated with a premium charged to all the system's end-users through the transmission toll.

Figure 1. Auction Awarded NC-RER Income Scheme



Source: Osinergmin.

The promotion of NC-RER by the Peruvian state successfully allowed several projects to be developed in the country. Four auctions were held between 2009 and 2015. Almost 1,300 MW of NC-RER capacity was awarded (see Table 1), mainly from mini-hydro plants (44 percent of the total). Wind and Solar projects, however, also showed high interest from investors, following mini-hydro at 31 percent and 22 percent, respectively.

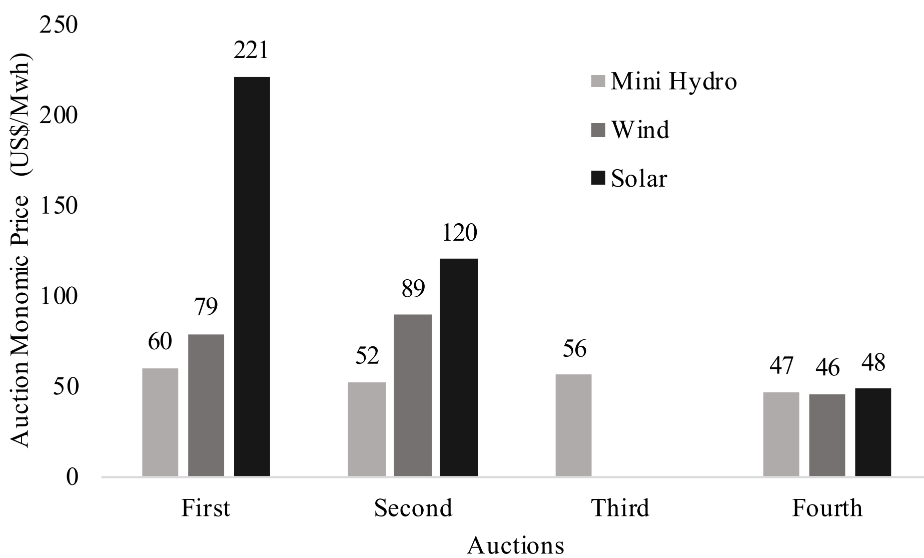
Table 1. NC-RER Auctions Installed Capacity Awarded in MW

Technology	In Operation	In Construction	Total	Share %
Mini Hydro	254	312	566	44%
Wind	358	37	395	31%
Solar	281	0	281	22%
Biomass	30	5	35	3%
Total	923	354	1,277	100%

Source: Osinergmin, COES.

Projects were awarded based on the lowest monomic price offers (including energy and capacity). As shown in Figure 2, since the first auction, the monomic price has been decreasing thanks to technological improvements, mostly in solar and wind projects, which led to lower CAPEX and higher plant factors. The first auction registered solar energy prices above US$ 200 per MWh, while wind and biomass were close to US$ 80 per MWh. By the fourth auction, held in 2015, wind, solar and mini-hydro energy had comparable prices of below US$ 50 per MWh.

Figure 2. NC-RER Auctions Average Prices by Technology

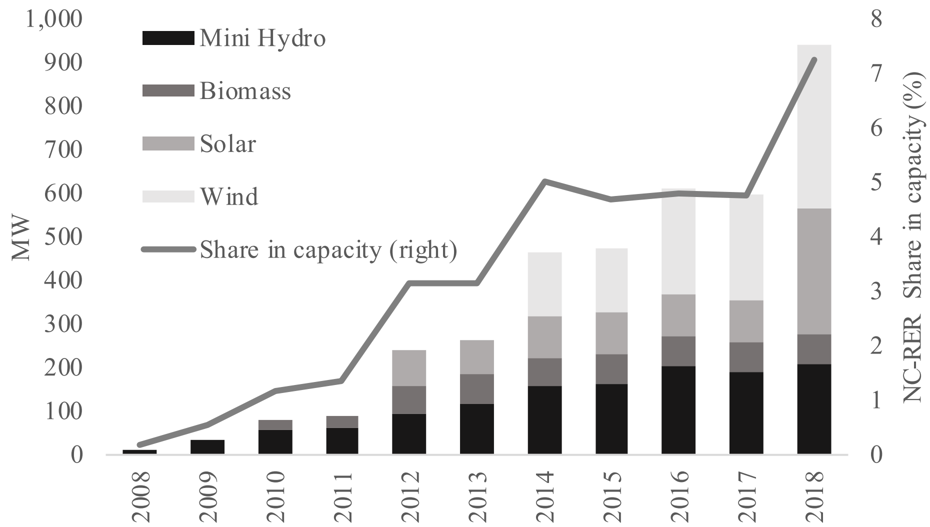


Source: Osinergmin.

NC-RER's share in total installed capacity has jumped from around half a percentage point by 2008 to 7.2 percent by 2018. By 2018, wind and solar accounted for almost 70 percent of total

NC-RER capacity, but this share is expected to decline in the years ahead as the remaining mini-hydro plants begin operations.

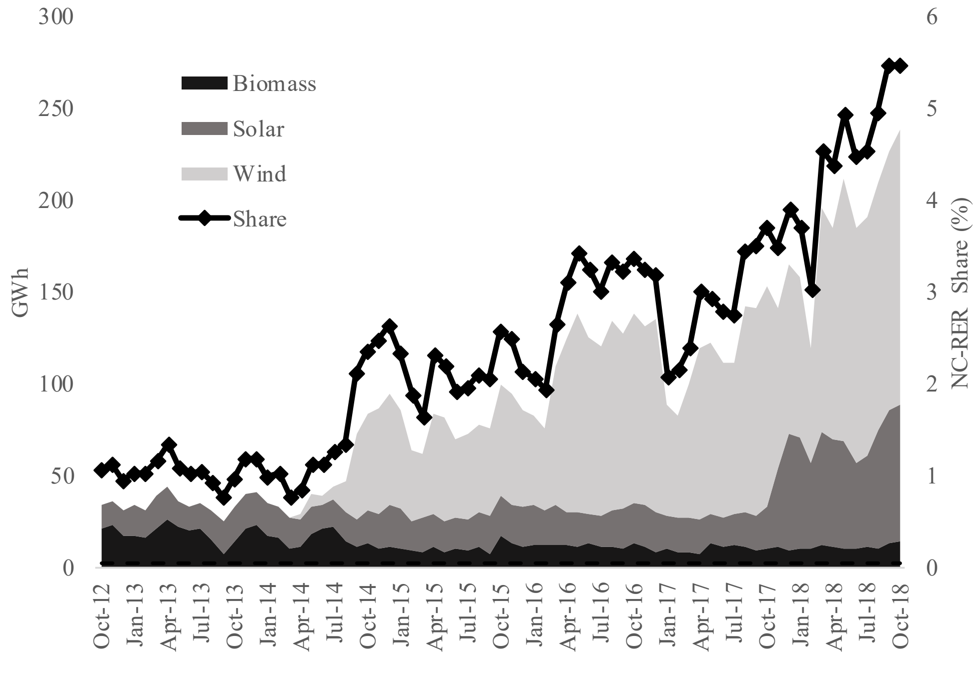
Figure 3. NC-RER Installed Capacity by Technology



Source: Osinergmin, COES.

The operation of Rubi, the largest solar plant of Peru with 145 MW of installed capacity, among other projects, allowed NC-RER generation (excluding mini-hydro) to grow 64 percent y/y in the Jan/Oct-18 period. In May-18, NC-RER reached 5 percent of total energy generation of the National Interconnected Electric System (SEIN by its acronym in Spanish), a level surpassed in Sep-18 and Oct-18 by a 5.5 percent share.

Figure 4. NC-RER Production by Technology and Share in Total Generation



Source: COES.

As can be seen, the current NC-RER promotion scheme has successfully attracted investment in the sector with greater competitiveness of solar and wind technologies in recent years. Also, the target of 5 percent share for NC-RER in energy consumption was reached in some months of 2018 and slightly sustained in 2019. However, the Government will have to assess the next target and the promotion mechanisms to be employed in the future. The existence of large reserves of natural gas and hydropower potential pose a relevant question of how much NC-RER the Peruvian system needs. Moreover, will new rounds of auctions be opened? Will NC-RER plants be allowed to contract in the PPA market? If so, is it possible for future NC-RER projects in Peru to compete in the PPA market without subsidies? How to deal with the intermittency given the availability of NG?

2.3 Problems of the NC-RER Promotion Scheme

Even though the auctions held in Peru have achieved interesting results in terms of attraction of investments, the promotion of ex-ante competition and the creation of simplified tender processes, the system's design, and associated contracts have shown some problems (Mitma, 2015).

Regarding the design, the target NC-RER quota to supply electricity demand has been achieved with a mechanism different from those applied to other technologies. NC-RER capacity is incorporated into the system at a zero “quantity risk” in the spot market, but with high impact on system operation and investment in other technologies. On the other hand, establishing a target quota subsidized by demand can only be justified by its positive externalities. An initial analysis was presented by García et al. (2011). However, by the time the NC-RER promotion was launched, the costs of these technologies were still high compared to others, and a low share in the optimal generation portfolio was estimated, even considering externalities.

Moreover, the compensation paid by users to NC-RER awarded projects through the premium has significantly increased lately due to the marginal cost decrease to an average of US$ 10 per MWh, and the slow growth of demand. As will be explained later, one of the reasons why marginal costs reached those levels is the declaration of natural gas prices to the Independent System Operator[2] (ISO) by thermal power plants. In 2018, the NC-RER cost an estimated US$ 185 million to end-users, around 5 percent of residential tariffs.

Another short-term problem is related to the bureaucratic costs and construction risk of mini-hydro projects. The inflexibility of contractual terms related to commercial operation and guaranteed income dates and periods implies that, when projects face engineering, financial or bureaucratic difficulties, they are at risk of not being implemented at all. For example, there are several projects in risk due to delays in permits. The Ministry of Energy and Mines recently pre-published a regulation that seeks to flexibilize contractual arrangements.[3]

In the medium term, the control of intermittence becomes a relevant concern. The absence of complementary services or backing-up of intermittent renewables either by market mechanisms or social planners can lead to the instability of the system. In that sense, several strategies must be designed to cover the new risk that can arise.

[2] In the Peruvian electricity sector, the Independent System Operator (ISO) is the Committee of Economic Operation of the National Interconnected System (COES by its acronym in Spanish). Throughout the paper, ISO and COES are used interchangeably.

[3] Ministerial Resolution N° 453-2018-MEM/DM, published in November 2018, pre-publishes a Supreme Decree that modifies certain conditions of awarded NC-RER supply contracts in order to flexibilize dates and terms that should be fulfilled by concessioners.

3. The Natural Gas Market for Electricity Generation in Peru and Its Rigidities

In Peru, the natural gas (NG) market is concentrated around the Camisea project infrastructure, considered the largest private investment project in Peru's history. The main gas well in the Camisea Project is Lot 88, which is intended exclusively for national consumption. Lot 88's reserves, which represent 69.5 percent of total NG reserves in Peru, are expected to last more than 35 years. Its composition shows a high ratio of natural gas liquids compared to other gas wells around the world.

A single pipeline, concessioned to Transportadora de Gas del Peru (TGP), transports NG from the Camisea fields, but it is bifurcated after the NG is processed to separate liquids from wet natural gas. The pipeline departs from the Peruvian rainforest to the central coast of the country. The main consumer of NG in Peru is the power generation sector, distantly followed by the industrial sector.

There are three sources of rigidities in the NG market that affect power generation. First, supply contracts between generators and the producer have high take-or-pay quantities. The second is the regulatory requirement to contract firm transport capacity to recognize firm power capacity. In the electricity sector, thermal power plants must contract firm transport capacity to receive capacity payments from the system and contract with distribution companies and non-regulated clients. Finally, institutional restrictions on the pack line represent a source of inflexibility in the system operation.

3.1 Natural Gas Issues

3.1.1 Supply Contracts of NG for Power Generation

As mentioned, in Peru, the access of the power generation industry to natural gas is mainly related to the Camisea Project, which started operations in 2004. Contractual conditions and prices were designed to fit the project's characteristics. In fact, the Camisea Project was established under a legal contract with a price cap and its restatement formula; that is, market forces do not guide prices at the well-head.

Capacity is contracted at a daily rate or "CDC" (for daily contracted quantity in Spanish). The producer is responsible for supplying natural gas up to a maximum daily quantity or "CDM." Contracts also establish a take-or-pay percentage (%TOP), a minimum quantity for which the client will pay even if it does not consume the natural gas. This condition is established to decrease the upstream operator's demand risk.

Current market conditions, where natural gas demand from generation companies decreased due to higher hydro and NC-RER energy supply, were managed thanks to mechanisms that introduced flexibility in contracts such as make-up and carry-forward conditions. In the first case, natural gas taken above the take-or-pay level can be deducted from future payments up to a certain number of months. In the second, consumption above the take-or-pay level is used as a credit against coming months where consumption is below the take-or-pay. On the other hand, the producer holds a "delivery or pay" obligation, which is 100 percent for power generators contracts in Peru.

3.1.2 Well-head Prices and Their Alignment with the Market

Well-head price caps in supply contracts were "designed" to make NG competitive against other power generation technologies.[4] The Camisea initial contract conditions were later changed, however, to a set of index prices of energy and oil equipment due to political considerations of electricity prices going up in the midst of the steep world oil prices increase of 2008. That decision delinked Camisea wellhead prices from fuel oil substitutes breaking up from a relative price-based policy to a cost-based policy, probably leading to a technologically dominant solution provided by NG.

In addition to this, the design of wellhead prices implied price differentiation between electric consumers and non-electric consumers. In fact, natural gas consumers would pay a wellhead price of 1.8 per MMBTU, but power generation plants paid a discounted price of US$ 1.0 per MMBTU. Current contracts also prohibit clients from selling natural gas to third parties. This condition is set to avoid arbitrage strategies between power generation and industrial companies since the latter have a higher wellhead price. Thus, a secondary market did not develop, and generation companies are unable to decrease their exposure to their take-or-pay contracts.

It is important to remark that other natural gas fields in Peru are not subject to the same regulatory conditions, which means that market conditions in Camisea will influence well-head prices in other blocks to be developed. This situation supposes a potential new problem associated with the competition among generators that will arise from these new contracts.

[4] The Camisea NG fields have a high percentage of condensates that were monetized at market prices.

3.1.3 Transport and Distribution of Natural Gas

There is a single pipeline for the domestic market, and it is operated by TGP. Transport service of natural gas can be provided through firm or interruptible services. Firm transport includes reserved capacity in the pipeline, and under normal circumstances, it cannot be decreased or interrupted by the operator. Moreover, firm contracts establish a daily reserved capacity, which is the maximum transport obligation of the operator. In exchange, the client pays a tariff independent from the level of effective consumption. That is, the client has a 100 percent delivery-or-pay condition. Interruptible service is subject to total or partial interruption of contracted capacity. However, if there is available capacity in the pipeline, the operator is bound to offer it to the client up to the contracted capacity. In contrast to firm contracts, clients only pay for their effective consumption.

By 2006, in order to encourage the contracting of natural gas transport in firm, Osinergmin established a tariff mechanism in which the expense for contracting under the firm or interruptible modality is the same. For equating both costs, the price of the interruptible transport must be equal to the base rate divided by the utilization factor with which the equality in spending was met:

$$Interruptible\ rate = \frac{Base\ rate}{Utilization\ Factor}$$

Since either firm or interruptible transport service expenses are the same, current prices do not reflect the differences in costs and risks of each kind of service. Since 2009, the utilization factor has been updated and now accounts for 90 percent according to the regulatory framework. This level of utilization factor makes the interruptible modality attractive for consumers with a utilization factor lower than 90 percent and unattractive for those with a factor greater than 90 percent. The interruptible rate modification equates the incentives to contract interruptible and firm transport service. In that sense, this new scheme still incentivizes the contract on firm capacity.

In June 2008, Law Decree 1041 modified the definition of "Firm Capacity." In the regulation of the Peruvian power sector, Firm Potency is necessary for power plants to receive capacity payments from the system as well as contract with distribution companies and non-regulated clients. The Law Decree established that thermal power plants will only receive monthly capacity payments if they have a continuous and permanent supply of fuel through contracts that guarantee it, or have available fuel stock. This was reflected in the Law of Concessions as an obligation for gas-fired power plants to contract firm transport service in order to have Firm Potency recognized by the system.

3.1.4 Line Pack Inflexibilities

In the Peruvian case, about a third of the power generation installed capacity and most NG-fired generation depend on the Camisea pipeline. Given the length, pressure and diameter of the pipeline, the Ministry of Energy and Mines (Minem) estimated that the line pack has a total capacity of 1,900 MMCF, equivalent to 3 days of natural gas consumption nationwide under normal conditions. This capacity can only be used to supply power plants in emergencies, determined by the Minem (Supreme Decree 017-2018-EM), and maintaining specific technical parameters such as minimum pressure. In normal conditions, line pack capacity is not available for users and, contractually, it is an asset of the concession.

Two other interdependent issues involving the line pack must be considered in the Peruvian case. First, although fully contracted, the transport capacity of natural gas is not fully utilized, except during peak periods, with some 400 MMPCD reinjected into the system daily. On the other hand, there are institutional restrictions. Line pack is an asset of the concession, and therefore there is a lack of development of the regulatory framework that would allow its efficient use.

Nowadays, the NG industry displays a high interdependence among upstream producers, the transport operator and large end-users. The existence of one main source of the fuel, one pipeline, and the concentration of demand means that any distortion is transferred from one agent to the other. Lower energy dispatch by NG-fired power plants means that the producer in Block 88 must decrease its output as well or increase reinjection rates. As NC-RER capacity in the Peruvian system grows, the impact of intermittence on NG consumption could require further flexibilization and regulation of line pack, which must be compatible with the concession contract of the operator. In short, in the years ahead, it will be necessary to develop a regulatory framework for new market demand and promote new services.

3.3 Impact of NG Market on Electricity Generation

There are three main sources of rigidities in the NG market that affect power generation. First, supply contracts between generators and the producer have high take-or-pay quantities. The second is the regulatory requirement in the electricity sector to contract firm transport capacity to recognize power capacity. According to this requirement, thermal power plants must contract firm transport capacity to receive capacity payments from the system and contract with distribution companies and non-regulated clients. A third source of rigidities is the institutional restrictions of the line pack as a source of inflexibility in the system operation. In this section, we analyze in detail the impact of these rigidities in the electricity market.

3.3.1 NG Supply Contract Conditions and Electricity Generation

As mentioned above, the make-up and carry-forward clauses led flexibilization to happen in order to manage the effective consumption and TOP payments. In fact, CDC by power generators is close to 600 MMCFD, of which 59 percent has a take-or-pay condition. These companies are in a range of take-or-pay between 75 percent and 90 percent. While make-up conditions can last between 6 and 18 months depending on the contract, the most recent contracts have shorter make-up periods. Recent contracts also do not include carry-forward conditions.

Table 2. NG Contracting Conditions of Power Generators

Client	CDM MMCFD)	CDC (MMCFD)	%TOP	CTOP (MMCFD)	DOP (MMCFD)	Make-up Recovery Time (months)	Carry Forward	Carry-Forward Period
Enel	137.76	74.16	100%	74.16	100%	18	Yes	18
Kallpa	150.09	78.58	100%	78.58	100%	18	Yes	18
Engie	139.49	69.75	100%	69.75	100%	18	Yes	18
SDFE	14.13	7.06	100%	7.06	100%	18	Yes	18
Egasa	20.16	10.08	100%	10.08	100%	18	Yes	18
Egesur	4.59	4.59	75%	3.44	100%	6	-	-
Fenix	-	84.1	90%	75.69	100%	6	-	-
Termochilca	-	45.03	70%	31.52	100%	6	-	-

Maximum Capacity Contracted in MMCFD	595.35
Maximum Capacity Contracted under TOP conditions in MMCFD	350.28
Share in Capacity under TOP conditions	58.84%

Source: Osinergmin.

Considering the efficiency of plants, contracted capacity under take-or-pay conditions in Peru reaches around 1,805 MW. Moreover, considering hydro and NC-RER capacity, the total power capacity would be above SEIN demand (5,525 MW). That is a partial explanation of why spot prices reached such a low level. Overcapacity in the NG power plants segment led them to declare a zero NG price to the ISO in order to dispatch and consume their high take-or-pay. Marginal costs are expected to average US$ 10 per MWh at least until 2020.

Table 3. Equivalent Capacity Supply of NG under Take-or-Pay Conditions

Client	CTOP (MMCFD)	CTOP (MMBTU)	Heat Rate (MMBTU per MWh)	Equivalent MW
Enel	74.16	76,385	8.80	361.6
Kallpa	78.58	80,937	8.36	403.2
Engie	69.75	71,843	8.16	366.7
SDFE	7.06	7,272	10.50	28.9
Egasa	10.08	10,382	13.09	33.0
Egesur	3.44	3,543	8.89	16.6
Fenix	75.69	77,961	7.71	421.6
Termochilca	31.52	32,466	7.79	173.6
Total	**350.28**	**360,788**		**1805**

Capacity	MW
RER	600
Hydro	3,800
NG under TOP conditions	1,805
Total	**6,205**
Average of Maximum Demand	**5,525**

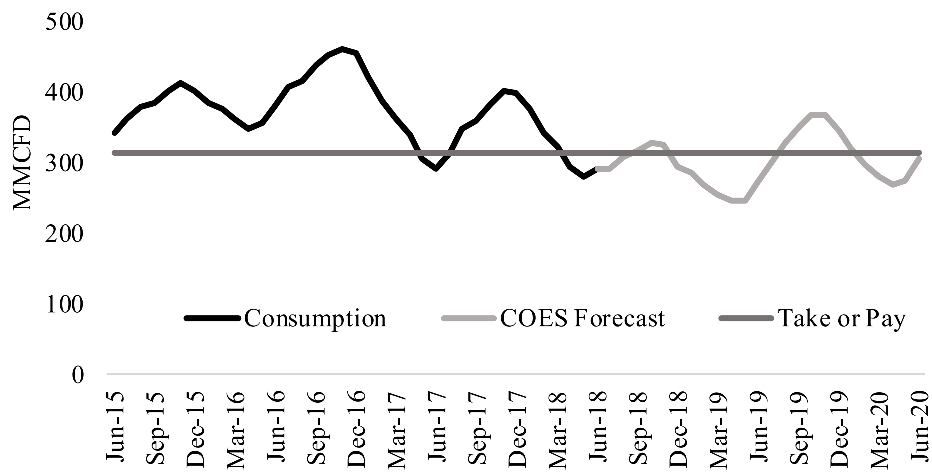
Source: Macroconsult based on Osinergmin and companies' information.

Moreover, most of the period between 2015 and 2018, the 6-month moving average has been above the TOP quantity. It proves that make-up and carry-forward mechanisms have helped to flexibilize the supplying of NG ex-post. According to the Committee of Economic Operation of the National Interconnected System[5] (COES) forecast, the consumption will still be above the TOP

[55] The COES purpose is to coordinate the short, medium and long-term operation of the National Interconnected Electric System (SEIN by its acronym in Spanish) at minimum cost, preserving the electricity system security and the efficient use of energy resources, as well as planning the development of the transmission and managing the wholesale market. It could be compared to the Independent System Operator (ISO) in the United States. Therefore, throughout the paper, ISO and COES are used indiscriminately.

quantity, leading to better use of the contracts. In that sense, the TOP condition represents a rigidity ex-ante, but the contract conditions help make it flexible and efficiently use the NG contracted. It explains why the supply contracts do not represent an inflexibility while transport contracts do. This argument will be further explored below.

Figure 5. Consumption of NG and Ship-or-Pay Contracts of Transport



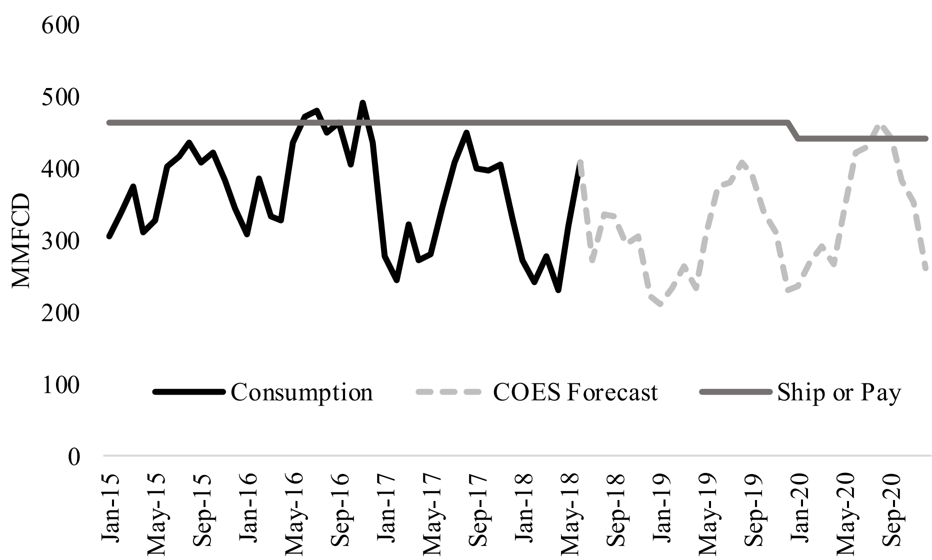
Source: Osinergmin and COES.

3.3.2 Loss of Competitiveness for NG Power Plants

Following the regulatory requirement, companies have contracted transport for almost all of their natural gas generation capacity through firm service conditions. Most of these firm transport capacity contracts will be finished by 2031. Contracted transport firm capacity is close to 464 MMCFD, leading to an important inflexibility in the natural gas market, as transport is a fixed cost. Transport rigidities, as we will discuss below, decrease the competitiveness of natural gas generation in the electricity market. The harm on competitiveness is mainly explained by the over-cost generated by NG's fixed transportation cost compared to other technologies. NG-fired power plants must contract firm transport capacity to recognize their firm power, while the recognition of the firm power of other technologies (e.g., hydropower plants) is based on a statistical methodology rather than a physical back-up their capacity, and it does not guarantee 100 percent availability at all times.

Figure 5 shows the seasonal pattern of natural gas consumption in Peru and the excess firm capacity contracted by the system. Effective consumption from power plants is permanently below the ship-or-pay capacity, only reaching it during some months of 2016. COES forecasts that NG consumption will be below ship-or-pay at least until 2020, and this situation has led NG generators to declare a zero (or close to zero) cost of NG to the ISO in order to increase their share of thermal dispatch and minimize the amount of NG paid for but not consumed. However, since all the companies have excess capacity contracted and there is no extensive secondary market for transport capacity, NG generators carry the financial burden of extra transport cost.

Figure 6. Consumption of NG and Ship-or-Pay Contracts of Transport

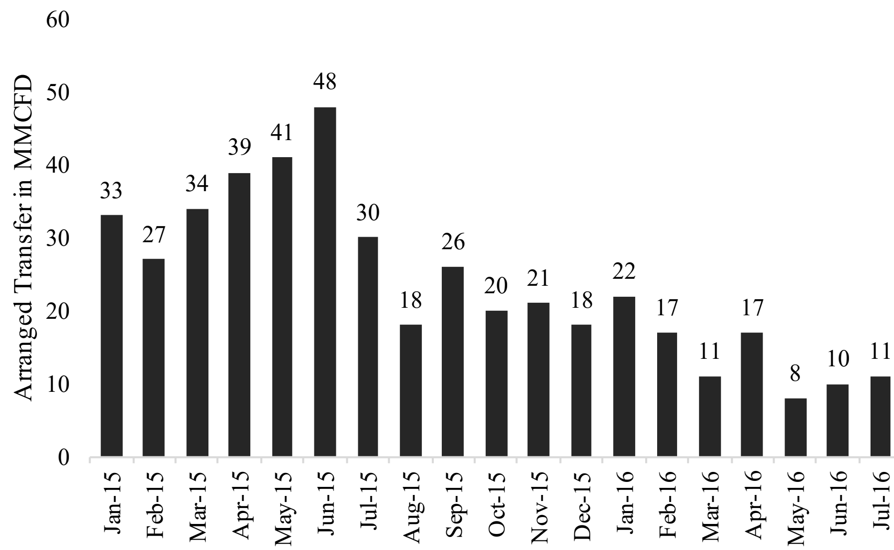


Source: Osinergmin.

Excess capacity of the transport infrastructure implied lower activity in its secondary market. Bilateral negotiations among consumers (mainly between NG generators) are done in a daily basis and are driven by capacity shortfalls for some market participants. Transactions declined between 2015 and 2016 due to an increase in transport capacity of the Camisea pipeline from 610 MMCFD to 920 MMCFD, which allowed deficit agents to increase their contracted capacity. The secondary market is expected to be more active once the electronic auction system is opened. However, its operation has been postponed by Supreme Decree N° 032-2017-EM, after several previous postponements in recent years. The spur of the secondary market will also depend on the supply-demand equilibrium in the NG transport capacity market.

On the other hand, variability in NG consumption could help to explain the dynamism in the secondary NG market. In the Peruvian case, most of the potential transactions would be led by power generators because they represent 40 percent of total NG consumption and the industrial sector is still small, along with the slow-growing residential segment. In that sense, variability in NG consumption is mainly guided by power generators, which have limitations on selling their surpluses or purchasing supplies to make up for shortfalls. Moreover, there is no significant seasonality in consumption because seasonal differences in temperature are not extreme. In that sense, the drivers that can explain more variability in NG consumption and, therefore, most likely, the dynamism in the secondary NG market are not strong.

Figure 7. NG Transport Capacity Transfers



Source: Osinergmin

3.3.3 Inflexibilities and Price Declaration Mechanism

Electric power dispatch in the Peruvian system is based on audited variable costs. However, Supreme Decree N° 016-2000-EM allowed NG-fired power plants to declare the price of its NG supply once a year, a core input for the calculation of plants' variable cost. This mechanism was considered useful for identifying the opportunity cost of NG. Oversupply in the market, with almost 13,000 MW of installed capacity versus a peak demand of 6,700 MW, and the inflexibilities of transport contracts lead companies to declare a zero natural gas price. Since companies' consumption was below the take-or-pay and ship-or-pay levels, NG opportunity cost was zero until they reached that minimum level. As a result, the marginal costs of the system decreased to an average of US$ 10 / MWh, negatively affecting suppliers with large shares of sales in the spot market. Intending to lessen this negative impact, the Minem issued Supreme Decree N° 039-2017-EM to establish the NG wellhead price multiplied by the non-take-or-pay share of supply as the minimum declared NG price.

4. Evaluation of the Peruvian Electricity Power Market in a Future Vision

In general, agents should carry only the minimum amount of long-term contractual obligations required to fulfill regulatory requirements. Rigid conditions will make it more difficult for agents to adapt to market cycles, like the current oversupply of capacity in the electric market, or technological changes. In Peru, that is the case of the requirement of 100 percent guaranteed transport of NG in order to obtain firm capacity and the high take-or-pay levels that the NG sector imposes on generation companies. In fact, these contract conditions are not internationally practiced. For example, in the United States, contracted firm capacity ranges from 44 percent to 78 percent, depending on the market. The lower take-or-pay is especially true for open-cycle plants, which are usually dispatched at irregular intervals depending on hydro and NC-RER supply in wet and dry seasons. Also, given their lower thermal efficiency, those plants must contract proportionally less of their capacity compared to combined-cycle plants

Oversupply of capacity could last until 2023, a context that can offer the opportunity for NG-fired power plants to act as back-ups or spinning reserves of the NC-RER supply. The lower environmental impact of NG and the flexibility provided by open-cycle plants could provide the opportunity for a "clean and cheap" hedge against NC-RER intermittence. A proper regulatory or market mechanism of compensation should be designed.

We consider adjusting the regulatory framework to allow NC-RER to sign power purchase agreements (PPA) with distribution companies or large clients necessary for a market solution, which means that the system would recognize and pay NC-RER plants firm capacity. The Ministry of Energy and Mines has proposed a methodology that equates the exigency levels to provide firm capacity both in conventional thermal or hydro power plants as well as for NC-RER technologies. Preliminary results from the methodology show that firm capacity would be approximately the plant factor of the technologies (around 25 percent for solar and 50 percent for wind) multiplied by the plants' nominal capacity.

Alternative market mechanisms such as contracting in energy blocks in certain hour ranges could allow NC-RER to have a scheme "adapted" to the usual availability of solar or wind energy. The "Electrical Concessions Law" would need to be modified so that contracts could only consider energy, instead of capacity and energy ("full requirement"), to allow for contract schemes such as those implemented in Chile. Additionally, NC-RER companies could establish back-up contracts with NG power plants to supply their clients whenever they are not available, hedging against spot market risk. As of now, NC-RER intermittence produces externalities to other plants of the system that are not compensated. Thus, they receive an implicit subsidy from conventional plants that should be internalized, whether by NC-RER producers or clients.

On the other hand, Galetovic et al. (2012) shows that quotas for NC-RER technologies with priority might not be an optimal solution for CO2 emissions, pollution and welfare. These authors find that a quota replaces investments in baseload technologies. This explains why the fees have little impact on CO2 and pollution in electric systems that expand their baseload based on hydro. They also find that quotas can be quite expensive, and their impact is non-linear. For the Chilean market, a 5 percent NC-RER share is an optimal solution from a simulation.

However, current rigidities in the Peruvian NG market make it costly for open-cycle plants to offer back-up to NC-RER due to the high fixed costs related to the NG supply necessary to recognize firm power capacity. Thus, a first flexibilization alternative would be to transit from individual supply contracts to a single buyer. The buyer would assign NG to the plants ordered to dispatch, COES could undertake this role. This solution would decrease companies' exposure to expensive take-or-pay contracts, and market risk would be more evenly distributed among suppliers.

In the case of transport, an option could be to adjust the regulation to consider the flexible dispatch nature of open-cycle plants and reduce the level of firm transport requirement to recognize firm power capacity. Thus, open-cycle plants could have a more appropriate mix of firm and interruptible capacity contracts. It would also allow for greater dynamism of the secondary market and lower agents' exposure to rigid contracts. Finally, due to the intermittence issue related to NC-RER technologies, a system reliability fee could be established in order to transfer part of NG back-up costs to end-users.

An essential consideration in the Peruvian case is that Camisea Project supply, transportation and distribution contracts include provisions protected by the legal contract. It means that the concession contracts for supply transportation and distribution have constitutional protection against any changes of terms and conditions by any other law. This ad-hoc mechanism parallel to the legal and regulatory framework is a symptom of Peru's weak institutional endowment. Strong arguments are required to introduce changes and if so, discuss policy options to remove the current framework and retain the economic and financial conditions of the former contracts.

In the years ahead, with greater NC-RER penetration and more variable natural gas consumption over time, the capacity of the line pack must grant more efficient use of natural gas, allowing better regulation of natural gas production in a manner resembling the frequency regulation in the electricity sector. Internationally, Spain has recently approved standards for using the line pack. The Spanish regulatory framework establishes that the technical operator of the system must sell or purchase natural gas in the short-run natural gas (e.g., intraday contracts) when there is a duct imbalance and depending on short-term flexibility and variability. Additionally, several measures have been adopted to seek more flexibility through tools to manage the risks arising from imbalances between injections and gas withdrawals (Fernández, 2018).

International studies must be considered when it comes to designing an efficient regulatory framework for pipeline in Peru. Hallack (2011) concludes that gas balancing rules should be consistent with market mechanisms that consider the cost of using the pipeline and not just the price of NG. Ameli, Qadrdan and Strbac (2017) have recently shown that proper use of the line pack can be a tool for reducing operation costs and increasing system security.

In light of current inflexibilities in the natural gas market and the country's potential to continue with the deployment of NC-RER technologies, the following section carries out a simulation analysis. The simulation's focus is on the social cost of the electrical system in which the share of NC-RER increases and the main rigidities of the Peruvian natural gas market remain in place.

5. The Future of NC-RER in Peru in a Context of a Flexible Natural Gas Market

In this section, we assess the effects of NG market inflexibilities on the share of NC-RER technologies and the power generation matrix composition in the long-term. Some papers, such as Kearns (2017), within a dispatch model, attempt to evaluate the impact of NC-RER intermittency in spot market prices. This kind of modeling, however, does not allow for a total cost of operation assessment in the medium or long-term.

We propose an analysis based on available information on capital and operation costs of different technologies and estimate the optimal power generation matrix (see the detail of costs and demand in the Annex). The analysis is based on classical peak load pricing models (see Crew, Fernando and Kleindorfer 1995), their replication in competitive markets (Joskow, 2006) and the incorporation of NC-RER technologies (Chao, 2011). The problem is solved by minimizing the expected costs of investment, operation and rationing of the electrical system (measured by the value of loss load, or VOLL, treated as a theoretical technology).

5.1 The Model

The approach consists of minimizing social costs and thus obtaining the optimal combination of technologies in the power market (see detailed derivation in Alayo and García, 2015). Mathematically, in a deterministic context, the optimization problem that must be solved is the following:

$$Min \qquad E\left(Voll * NSE + \sum_{i=1}^{i=T} b_i * E_i\right) + \sum_{i=1}^{i=T} \beta_i * Y_i$$

where:

E_i: energy supplied by the plant i

Y_i: capacity installed for each the technology i

a_i: average availability for each technology i

NSE: unsupplied energy

b_i: annual variable cost for each technology i

β_i: annual fixed cost for each technology i

It can be proved that this problem is equivalent, under certain assumptions, to the classic welfare maximization problem in partial equilibrium. It can also be estimated as the gross consumer surplus minus the total costs of providing the service (Alayo and García, 2015). In order to treat the optimization problem as a minimization, it is necessary to introduce the concepts of non-supplied energy and the "Value of Lost Load," or VOLL, instead of the consumer surplus. Using the concept of duality, the welfare maximization problem is converted into a minimization of the social cost of supplying electricity.[6]

Table 4. Peak Load Pricing and the Planning of Electrical Systems

	Approach	Objective Function	Results
Primal Problem	Welfare Maximization	Consumer Gross Surplus minus costs	Optimal price
Dual Problem	Social Cost Minimization	Value of Lost Load (VOLL) + CAPEX + Cost of O&M	"Cutting points" (times) and Optimal capacities to be installed

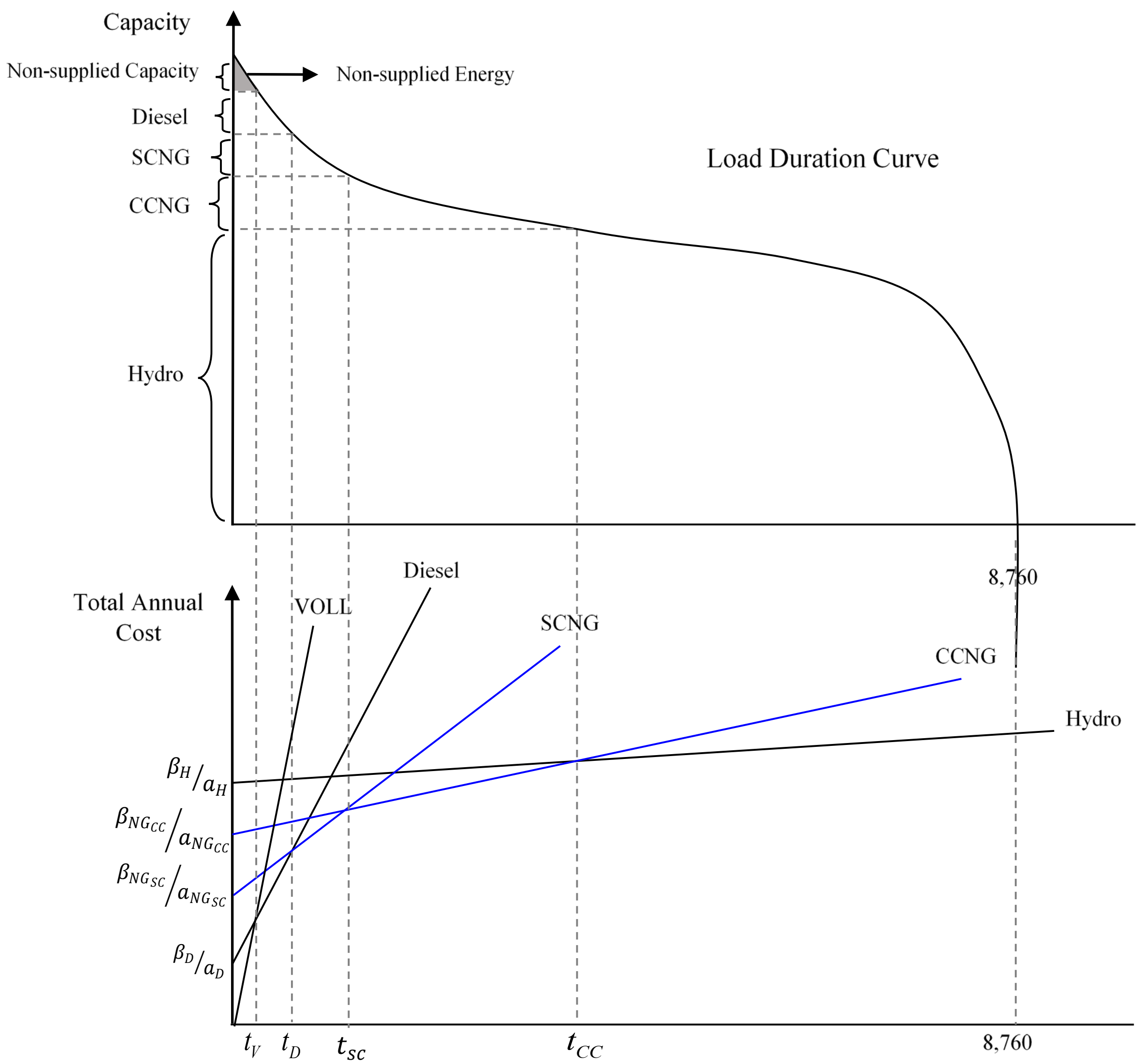
Source: Authors' compilation based on Alayo and García, (2015).

In graphic terms, the optimization strategy is determined by the relationship between the duration curve of demand and the technologies' cost functions. The hourly consumption pattern through a period, known as the load curve presented at the top of Figure 8, is used to construct the duration curve ordering demand from maximum to minimum demand along the 8,760 hours of a year. On the other hand, each technology's cost functions are represented as linear functions at the bottom of Figure 8. The optimization strategy involves identifying the envelope curve. Two relevant concepts in this optimization process are "non-dominated technologies" and "cutting points." The first refers to the technologies that are part of the envelope curve, made up of cheaper technologies through 8,760 hours. The "cutting points" are particular intersections between two function costs. Those points represent the cheaper cost in an hour block such t_D, referring to the intersection of diesel and Simple Cycle of Natural Gas (SCNG).

[6] Additionally, this result replicates the long-term equilibrium of a competitive power generation market as shown by Borenstein (1999) and Green (2000).

In that sense, non-dominated technologies determine the “cutting points” in demand and the hour ranges or blocks where each technology displays the greatest efficiency in supply as well as optimal capacity. The lower portion of Figure 8 below shows the existing technologies with their respective fixed and variable costs. All the technologies’ envelope curve must be found to plot their “cutting points” in the duration curve above. The duration curve and the “cutting points” will determine the operating time of each power plant and its respective installed capacity. The figure illustrates this rationale for optimization.

Figure 8. Optimal Combination of Generation Technologies



Source: Hunt (2002).

The first-order condition of the optimization is reached at[7]

$$\theta Prob(D(p_i) > \tilde{z}_i) = \frac{\beta_i/a_i - \beta_{i+1}/a_{i+1}}{b_{i+1} - b_i} \qquad \forall\ i = 1,2,\ldots,N$$

where we have a constant duration equal to θ, 8,760 hours in this case, and $\tilde{z}_i = \sum_{j=1}^{i} \tilde{Y}_i$ is s the available capacity up to technology i (ordered by variable costs). It incorporates the random nature of supply and demand, and the end-users valuation of outages in finding the optimal prices. If it is considered that the demands in the 8,760 hours are part of a data generating process, the probability can be replaced by ${}^{t_i}/_{\theta}$. Thus, the "cutting points" can be easily found replacing it into the first-order condition.[8]

Based on these considerations and following the analytical strategy of Chao (2011), we construct scenarios for the long-term configuration of the power generation matrix in Peru. Our analysis provides a referential optimal total cost, which will be the basis for analyzing policy options and their effects. In general, the assumptions made in this study attempt to show a future scenario in which there is no oversupply and the technology improves. The technologies considered are based on the available resources in Peru such as hydro, natural gas, diesel, solar and wind. The electricity demand considered is the Peruvian total demand, and the analysis assumes that oversupply will be ended.

5.2 The Data

Our projection extends to 2025. The costs have been calculated using a benchmark of recent generation projects capital and operation costs based on information provided by Osinergmin, Lazard and the U.S. Energy Information Administration (EIA). In fact, in order to obtain the most recent data, the capacity costs of solar and wind were taken from an international source, the Lazard's Levelized Cost of Energy Analysis (2018),[9] and not from a national source, as Peru's last RER auction took place in 2015. On the other hand, the other technologies' capacity cost was taken from Osinergmin for recent generation projects. The same methodology was applied to variable costs except for solar and wind, whose costs were considered zero.

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[7] It is assumed that $E_i = \sum_{i=1}^{t=T} \tilde{y}_i * t$. In that sense, $E(E_i) = \sum_{i=1}^{t=T} \theta * E(\tilde{y}_i) = \sum_{i=1}^{t=T} \theta * \frac{\tilde{y}_i}{ai}$

[8] $\theta Prob(D(p_i) > \tilde{z}_i) = \theta * \frac{t_i}{\theta} = t_i$.

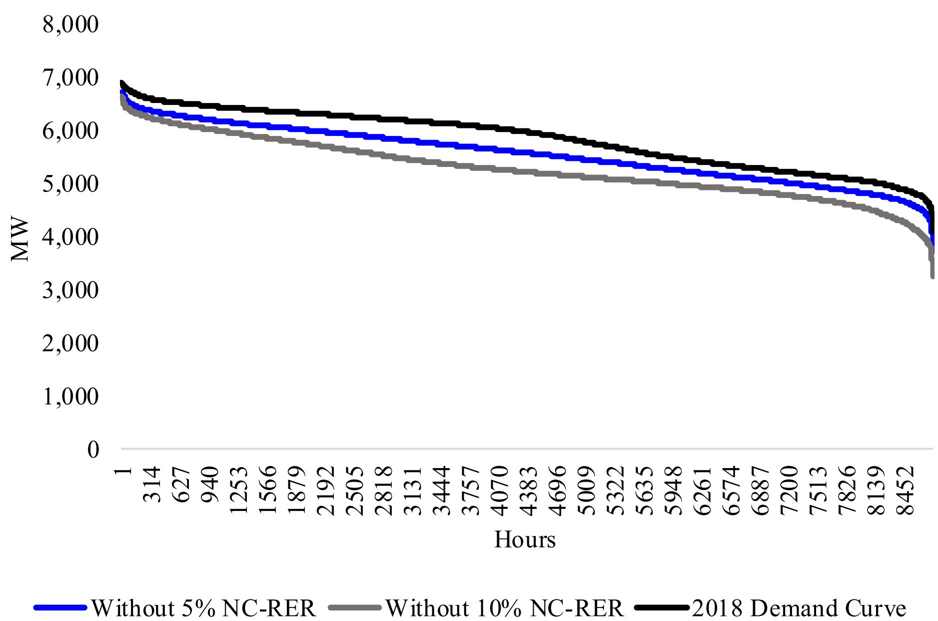
[9] https://www.lazard.com/media/450784/lazards-levelized-cost-of-energy-version-120-vfinal.pdf

Concerning social costs, it was not easy to locate research encompassing all the technologies considered in our generation matrix. Sovacool (2008), however, includes a survey of studies on CO2 equivalent emissions between 2002 and 2008. On the other hand, the price of CO2 equivalent emissions was based on Van Den Bergh and Botzen (2014), which shows that green bonds are underestimated and proposes estimating the real value of externalities based on project evaluation.

A load curve was estimated for both the presence and the absence of NC-RER, which helps us obtain the respective load factor for different NC-RER quotas. As shown in Figure 8, the load factor decreases as the NC-RER quota increases. In fact, the load curve in 2018 showed a load factor of 84.3 percent, while for a 5 percent quota it is 82.7 percent, and for a 10 percent quota, 79.2 percent. This pattern is explained by the intermittence and variability problems of NC-RER technologies. The estimation was based on 2018 data taken from COES. To illustrate solar and wind power plants, we chose the Rubí and Tres Hermanas power plants, respectively, since these are the most recent launched generation projects and their performance can be evaluated in 2018.

The simulation of the model was based on social costs since they internalize each technology's externalities and make the generation matrix more efficient.

Figure 9. Load Curve in 2018 by Scenario



Source: COES.

5.3 Scenarios, Results of Simulation and Discussion of Policy Options

Flexibilization in the NG market is understood as flexibilizing the contractual conditions of supply or transport service. In the Peruvian case, the main source of rigidities is transport service. While the supply contracts analysis shows that the carry-forward and make-up conditions mechanisms help to handle the apparent "inflexibility" of the TOP condition, transport service has neither flexible conditions nor a secondary market. As shown in Figure 6 above, transport services present large rigidities for the electricity sector since the paid capacity of transport is always over the effective use of that capacity, leading to a loss of competitiveness and an understatement of the price declaration. In addition to this, generators lose bargaining power to use more interruptible contracts due to the government's active promotion of firm contracts through the design of prices. These conditions compound the preexisting inflexibilities in the natural gas transport market.

In that sense, the base scenarios that have been constructed are the results of the optimization of the generation matrix with social costs under inflexible and flexible transport contracts. A first result of the simulation is that in both scenarios NC-RER technologies would not have a share in the Peruvian generation matrix since other technologies, such as hydro and natural gas, could take advantage of their potential. However, if a sensitivity analysis of the hydroelectric plants' costs and the future prices of natural gas are made, the results could change.

A first scenario considers the current contracting conditions of NG supply and transport. Thus, for NG power plants (open and combined cycle), the firm capacity contract is considered a fixed cost. Inflexibility reduces the share of NG, leaving more space for diesel and hydroelectric power plants, and NC-RER fails to be competitive even considering "hybrid" power plants that combine solar or wind energy with natural gas due to higher CAPEX. In this scenario, the existence of inflexible contracts raises the total costs of generation increase by 1.4 percent, from US$ 3,210 million annually to US$ 3,254.

A second scenario evaluates the effect of introducing a 5 percent NC-RER quota. We estimated that the impact of adding the NC-RER quota on total costs is higher in the scenario with inflexible gas costs (+1.4 percent) than the one with flexible costs (+1.0 percent). This is explained by the fact that the intermittent supply of NC-RER plants leaves a volatile residual demand that should be covered by conventional technologies. When the volatility of residual demand is higher, rigidities in NG contracts have a greater effect on the total production cost.

When the NC-RER quota increases to 10 percent, the marginal growth of costs in the scenario with inflexibilities appears to increase by 1.4 percent for the first 5 percent quota and 3.4 percent for the second 5 percent. In the case of a flexible NG market, that 5 percent additional quota has another +2.9 percent impact on total costs and is still the scenario with a cheaper cost of introducing NC-RER (see Tables 5 and 6 for a summary of results).

Another important result is that maintaining a 5 percent NC-RER quota in a fixed NG market costs 28 percent more (+US$ 13 million) than in a flexible one. On the other hand, maintaining a 10 percent NC-RER costs just 20 percent more (+US$ 31 million), showing an inverse relationship between the NC-RER quota and the cost of being in a flexible market. However, at the private cost level, the pattern changes. The over-cost for maintaining a 5 percent NC-RER quota is 26 percent, while for a 10 percent quota it is 31 percent more. It can be explained by the two forces in play here: the cost of greater variability in the dispatch of NG power plants due to a greater NC-RER quota and CO2 emissions cost. The results show that, at a social cost level, since it gets cheaper to increase the NC-RER quota, the CO2 emission cost is greater.

Table 5. Simulation Results with 5 Percent NC-RER Share by Scenario

	Total Cost (million US$)	Monomic Price (US$/MWh)
Without quota and Fixed Gas	3,254	44
Without quota and Variable Gas	3,210	44
NC-RER quota and Fixed Gas	3,300	46
NC-RER quota and Variable Gas	3,244	45
Cost of 5% quota with Variable Gas	33	2
Cost of 5% quota with Fixed Gas	46	2

Table 2. Simulation Results with 10 Percent NC-RER Share by Scenario

	Total Cost (million US$)	Monomic Price (US$/MWh)
Without quota and Fixed Gas	3,254	44
Without quota and Variable Gas	3,210	44
NC-RER quota and Fixed Gas	3,411	49
NC-RER quota and Variable Gas	3,336	48
Cost of 10% quota with Variable Gas	126	4
Cost of 10% quota with Fixed Gas	157	5

It is important to note that the results are subject to a series of assumptions regarding the Peruvian regulatory framework. From the results of the simulation, if we migrate from fixed conditions in the NG market to a more flexible context, the transport operator would have an income gap of approximately 47 percent, which would need to be covered by an increase in tariff rates of around 80 percent, or with other customers. Appropriate compensation to the current operator in case of migration to a more flexible NG market must be analyzed considering the results of this model but considering other regulatory details as well.

Current market conditions show that long-term contracts have been signed, and ship-or-pay obligations could last until the end of the next decade for certain power generators. Second, and most importantly, a revenue gap could emerge in the transport concessioner's financial results, requiring the design of regulatory compensations that could be charged to users. However, in this last case, the need for transport capacity for other uses must be analyzed to measure that gap.

As the results indicate, flexibilization is the main recommendation for obtaining a cheaper and more sustainable generation matrix. Then, the question of how to implement flexibilization must be resolved in order to increase efficiency in the power market. First, to approach a more flexible scenario, it is necessary to attack the main rigidity source, NG transportation. Therefore, the requirement of 100 percent firm transport contracts to receive the capacity payment must be eliminated. This measure will create a secondary market, where the paid capacity but not transported may be exchanged between deficit and surplus users. At this point, the electronic auction should be implemented under the regulation of the Secondary Natural Gas Market.

Another policy option is to put a single transport buyer in place, which would become an efficient allocator of capacity. Generators would then only pay for usage of capacity and no longer have firm contracts. It is further necessary to develop an operator with a more economical approach to establish the single-buyer measure and ensure the development of a line-pack market in the future.

6. Conclusions and Recommendations

In this paper, we have shown that rigidities in the current regulatory framework in Peru for NG supply by power generation plants are inefficient compared to a flexible framework that allows NG-fired power plants to have a larger share of interruptible transport contracts. That is, the rigid scenario has a larger system operation cost than the flexible scenario. The inclusion of a NC-RER quota and greater NG capacity back-up requirements due to higher impact of intermittency in the system is cheaper in the flexible scenario.

We suggest that the requirements of the regulator for NG supply and transport contracting should be reviewed. A minimum rate of a firm contracting suitable for the operative and economic characteristics of open and combined cycle plants would allow for greater flexibility of supply and lower the financial burden for the power generation industry. In general, a more flexible framework should be implemented. Other options for flexibility, although more complex due to the existence of contracts, include creating a single buyer of NG and/or designing a mechanism that allows the use of the NG pipeline line pack. Ameli, Qadrdan and Strbac (2017) have recently shown that proper use of the line pack decreases operation costs and increases the electric system's security. Moreover, the NG transport operator's tariff scheme and the cost recovery mechanism of the NG transport concession will need to be assessed.

We further suggest that the NC-RER promotion mechanism be modified towards a more "market-oriented" scheme. Allowing NC-RER to compete with other technologies in the contracts market will be possible if the regulatory framework includes wind and solar plants when considering firm power capacity. In fact, a methodology that considers NC-RER peculiarities and the level of confidence of their supply was recently proposed by the Minem. Another improvement could be allowing a contract mechanism of energy hourly blocks Additional to the current Power Purchase Agreements (power and its associated energy).

The improvements discussed above would allow for better use of complementarities between NC-RER and NG power plants in Peru.

Finally, the electrical system's operation should be more deeply integrated with the NG system, improving efficiency and system security. In the Peruvian case, a single buyer of natural gas for power generation could be a viable mechanism for decreasing generators' exposure to take-or-pay conditions. A market mechanism that allows the use of the line pack is also relevant for the future development of NC-RER capacity in the country, leading to higher intermittency impact on the system. We expect that the policy recommendations provided in this paper will have a more significant impact once the problem of over-supply in generation capacity is solved, which is likely to occur around 2024. Thus, policymakers and market agents would then have a window of opportunity to discuss and implement proper adjustments to the current regulatory framework.

Data Appendixes

Appendix 1. Annual Fixed Cost with Fixed Natural Gas

Type of Power Plant	Unit Cost (thousands of US$ per MWh)	Life (years)	Annuity Factor	Annuity (thousands of US$ per MW-year)	O&M Fixed Cost (%)	O&M Fixed Cost (thousands of US$ per MW-year)	Additional Fixed Cost (thousands of US$)	Annual Fixed Cost (thousands of US$ per MW-year)	Average Availability	Annual Fixed Cost (thousands of US$ per MW-year)
Coal	1,590	25	0.11	175	3%	48	-	223	0.95	235
Diesel	565	25	0.11	62	3%	17	-	79	0.95	83
SCNG	650	25	0.11	72	3%	12	128	211	0.95	222
CCNG	1,051	25	0.11	116	1%	11	83	210	0.95	221
Hydro	2,447	40	0.10	250	2%	49	-	299	0.95	315
Solar	950	25	0.11	105	3%	29	-	133	0.35	380
Wind	1,150	25	0.11	127	3%	35	-	161	0.50	322
Hybrid Solar	-	-	-	-	-	-	-	344	0.95	362
Hybrid Wind	-	-	-	-	-	-	-	372	0.95	392

Note: Additional Fixed Cost is calculated with the fixed charge of NG price and the specific consumption factor.

Appendix 2. Annual Fixed Cost with Variable Natural Gas

Type of Power Plant	Unit Cost (thousands of US$ per MWh)	Life (years)	Annuity Factor	Annuity (thousands of US$ per MW year)	O&M Fixed Cost (%)	O&M Fixed Cost (thousands of US$ per MW-year)	Annual Fixed Cost (thousands of US$ per MW year)	Average Availability	Annual Fixed Cost (thousands of US$ per MW year)
Coal	1,590	25	0.11	175	3%	48	223	0.95	235
Diesel	565	25	0.11	62	3%	17	79	0.95	83
SCNG	650	25	0.11	72	3%	12	84	0.95	88
CCNG	1,051	25	0.11	116	1%	11	126	0.95	133
Hydro	2,447	40	0.10	250	2%	49	299	0.95	315
Solar	950	25	0.11	105	3%	29	133	0.35	380
Wind	1,150	25	0.11	127	3%	35	161	0.50	322
Hybrid Solar	-	-	-	-	-	-	217	0.95	228
Hybrid Wind	-	-	-	-	-	-	245	0.95	258

Note: Additional Fixed Cost is calculated with the fixed charge of NG price and the specific consumption factor.

Appendix 3. Variable Cost by Technology with Fixed Natural Gas

Type of Power Plant	Unit Cost (US$ per fuel*)	Specific Consumption Factor (Fuel per MWh**)	Variable Cost in Fuel (US$ per MWh)	Variable Cost in other expenses (US$ per MWh)	Private Variable Cost (US$ per MWh)	Additional Social Cost	Social Variable Cost (US$ per MWh)
Voll	-	-	-	-	3,500	-	3,500
Coal	110	0.3	38	2	40	120	160
Diesel	676	0.2	162	4	166	97	263
SCNG	2	9.8	20	2	22	85	106
CCNG	2	6.4	13	3	16	55	72
Hydro	-	-	-	-	0.6	1.4	2.0
Solar	-	-	-	-	-	4.0	4.0
Wind	-	-	-	-	-	1.3	1.3
Hybrid Solar	-	-	-	-	14.1	56.6	70.7
Hybrid Wind	-	-	-	-	9.8	39.0	48.8

Notes: * Liquid Fuel: US$/Ton, Natural Gas: US$/MMBTU, Coal: US$/Ton
* Liquid Fuel: Ton/MWh, Natural Gas: MMBTU/MWh
Oil barrels per Ton Oil Equivalent = 7.33
Price of Diesel (US$/barrel) = 92.3
Exchange rate = 3.33

Appendix 4. Variable Cost by Technology with Variable Natural Gas

Type of Power Plant	Unit Cost (US$ per fuel*)	Specific Consumption Factor (Fuel per MWh**)	Variable Cost in Fuel (US$ per MWh)	Variable Cost in other expenses (US$ per MWh)	Private Variable Cost (US$ per MWh)	Additional Social Cost	Social Variable Cost (US$ per MWh)
Voll	-	-	-	-	3,500	-	3,500
Coal	110	0.3	38	2	40	120	160
Diesel	676	0.2	162	4	166	97	263
SCNG	3	9.8	34	2	36	85	121
CCNG	3	6.4	22	3	26	55	81
Hydro	-	-	-	-	0.6	1.4	2.0
Solar	-	-	-	-	-	4.0	4.0
Wind	-	-	-	-	-	1.3	1.3
Hybrid Solar	-	-	-	-	23.6	56.6	80.1
Hybrid Wind	-	-	-	-	16.3	39.0	55.3

Notes: * Liquid Fuel: US$/Ton, Natural Gas: US$/MMBTU, Coal: US$/Ton
* Liquid Fuel: Ton/MWh, Natural Gas: MMBTU/MWh
Oil barrels per Ton Oil Equivalent = 7.33
Price of Diesel (US$/barrel) = 92.3
Exchange rate = 3.33

Appendix 5. Natural Gas Price in Different NG Market Contexts

Price of Natural Gas	Variable NG Market		Fixed NG Market
	Variable (US$ per MMBTU)	Fixed (US$ per MMBTU)	Fixed (US$ per MMBTU)
Provision	2.0	-	2.0
Transport	-	1.1	1.1
Distribution	-	0.4	0.4
Total	2.0	1.5	3.5

Appendix 6. Load Curve Aspects

Linear Duration Curve: D(t) = Maximum Demand - m*t	
Intercept (Maximum Demand)	10,000
Scope (m)	0.36
Minimum Demand	6,845
Hours in a year	8,760
Total Energy Demanded	73,780,358
Total Energy Supplied	73,780,245
Load Factor	84.3%

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