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ANALYSIS OF LOCAL MARGINAL PRICES IN TRANSMISSION SYSTEMS DOMINATED BY HYDROELECTRIC GENERATION

ANÁLISIS DE PRECIOS MARGINALES LOCALES EN SISTEMAS DE TRANSMISIÓN DOMINADOS POR GENERACIÓN HIDROELÉCTRICA

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Resumen

En los mercados eléctricos competitivos, las señales de precio son fundamentales para guiar las decisiones de inversión en expansión y repotenciación de la red, especialmente cuando se identifican congestiones en generadores, transformadores y líneas de transmisión, por lo que este artículo propone una metodología para analizar dichas congestiones en el Sistema Nacional Interconectado (SNI) Ecuatoriano mediante un modelo de optimización con flujo DC que incorpora pérdidas eléctricas, determinando los Precios Marginales Locales en cada nodo bajo tres escenarios clave: red sin límites de transmisión, red con capacidad real de los elementos y red real incluyendo pérdidas, cuya comparación permite identificar y cuantificar las congestiones y su impacto económico, obteniendo así índices cuantitativos que asisten al planificador en la toma de decisiones óptimas de inversión, con resultados preliminares que revelan puntos críticos de congestión en líneas y generadores específicos cuya repotenciación minimiza los costos globales de operación del sistema.

Palabras clave: Planificación energética, Precios marginales, Incertidumbre, Costo marginal, Precios nodales, Congestión en las líneas, Pérdidas en las líneas.

Abstract

In competitive electricity markets, price signals are essential for guiding investment decisions on grid expansion and repowering, especially when congestion is identified in generators, transformers, and transmission lines. This article therefore, proposes a methodology for analysing such congestion in the Ecuadorian National Interconnected System (SNI) using an optimization model with DC flow that incorporates electrical losses, determining the Local Marginal Prices at each node under three key scenarios: a network without transmission limits, a network with the actual capacity of the elements, and a real network including losses. Comparing these scenarios allows for the identification and quantification of congestion and its economic impact, thus obtaining quantitative indices that assist planners in making optimal investment decisions. Preliminary results reveal critical points of congestion in specific lines and generators whose repowering minimizes the overall operating costs of the system.

Keywords: Energy Planning, Marginal prices, Uncertainty, Marginal cost, Nodal prices, Line congestion, Line losses.

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1. Introduction

Currently, in Ecuador as well as in different countries, the electric systems face new challenges related with the electric demand increasement, the introduction of variable renewable generation sources and the uncertainty produced by these technologies [1], the study of nodal prices or LMP (Location Marginal Prices), is a topic of analysis and great importance, due to it is precise to stablish adequate rates that provide efficient and optimal economic signals [2].

The analysis of congestion as an indicator of the application of models for planning the expansion in generation and transmission must consider various factors, such as the incorporation of new electrical infrastructure, the construction of generating plants, substations and power transmission lines [3], [4]. Generally, the electricity prize for each period is determined by the variable cost of the last required generation unit to meet the demand [5]. That one that has available generation capacity, which is why said unit is called Marginal. It is important to point out that the operators of the electrical market include in the offer prizes of the lines transmission restriction trough which energy is sold. Whence the problems such as trapped charge or generations required to maintain the operation of the power system within safe ranges become conditions that agents use to influence nodal prices or to achieve higher margins in the market, due to their strategic position in the transmission system.

In many electricity markets, the busbar price is determined without considering congestion, and losses are approximated to calculate the market cost [6]. For example, the authors in [5] utilize a DC flow methodology to estimate losses. The current methodology does not account for reactive power or uncertainty in renewable energy sources. However, other authors, such as [7] and [8], present linearized flow equations that assist in determining losses by finding a global optimum [9]. Additionally, some authors, like [10], develop methods to account for the uncertainty in local nodal prices. Nonetheless, their optimization models rely on a DC flow model and do not incorporate electrical energy losses. In [11], the issue of how strategic generators interact in deregulated electricity markets is addressed using machine learning to maximize profits, including the integration of distributed generation and grid faults. Meanwhile, in [12], the authors examined settlement, congestion, and financial instruments within the electricity market. However, the LMP decomposition depends on the energy reference bar used in the OPF model, and the simulation is carried out in a simplified system.

Because of restrictions on the transmission network and on the operation of electric generators, energy flows are redistributed and more expensive units are used [13]. As a result, nodal price separation occurs, and marginal power lines (MPL) increase. Therefore, the MPL reflect not only the marginal cost of energy, but also the cost of maintaining system reliability and stability.

Local marginal process must account for losses and congestion in transmission lines, generators, transformers, and other components. This is necessary to determine the true cost of the transition between electricity supply and demand. Previous literature review linearizes the marginal price level (LMP) using DC flow. However, they do not consider actual AC losses, which could lead to price signal deviations.

Based on the above, we suggest developing an optimization model implemented in Python using Pyomo and the GLPK solver. This model aims to determine nodal prices in the National Interconnected System (SIN) under three scenarios. The first scenario assumes unlimited transmission line capacity, allowing analysis of system behavior without network constraints. The second scenario incorporates actual transmission line capacities, without considering electrical losses. The third scenario includes both real line capacities and network losses, resulting in a nonlinear optimization problem. Because of this complexity, the last case is solved using the IPOPT solver. The database feeding the model is obtained from simulations performed in the DIgSILENT PowerFactory software. The data is automatically extracted using a Python script developed within the PowerFactory environment, enabling efficient integration of simulation results with the optimization model.

2. Methodology

2.1.1. LMP composition

2.1.1.1. Energy price

The Price is determined by disregarding both losses and network constraints, that is, by performing an ideal energy dispatch. In this stance the LMP (Lower Maximum Permissible Limit) is equal to the single-node price with infinite transmission line capacity.

2.1.1.2. Network restrictions

This component is associated with the operational constraints of the equipment that makes up the electrical power system. Such as thermal, voltage, and stability limits. The cost of constraints arises when these limitations prevent the dispatch of lower-cost generators, forcing the use of more expensive units located closer to load centers to meet demand. This price component is zero when the grid has no active constraints or when the system operates well beyond its operational limits.

2.1.1.3. Transmission system losses

Transmission system losses increase generation requirements and depend on the technology, usage, and length on the lines. The price generated by these losses is justified by the relative location effect between generation and demand: when a load is electrically distant from the marginal generator, this price component increases at its node; conversely, it decreases when the load is closer.

This price formation mechanism is applied in both developing and developed electricity markets because it improves efficiency and maintains transparency in the system, generating economic signals for new investments in generation or transmission.

The calculation of nodal prices is based on optimization models, such as DCOPF and ACOPF; in practice, DCOPF is used because its simplicity and speed, while ACOPF is used for offline studies because of its greater accuracy [14].

2.1.2. Optimal power flow

Optimal power flow involves determining the state variables of a power system by optimizing an objective function while simultaneously adhering to a set of physical operational constraints. In this study, the objective function is to minimize generation costs subject to network equality and inequality operational constraints. Therefore, solving the optimization problem provides the inputs for calculating the maximum permissible limits (MPL).

The DC model is an approximation of the AC model, which can be solved more quickly and generally yields a global optimum [15]. Therefore, the equation used to solve case studies 1 and 2 corresponds to the DC optimization model.

$$\min z = \sum_{i \in N} Ci * pgi \tag{1}$$

$s.a$

$$\sum_{i,j \in L} fi,j - \sum_{j.i \in L} fj,i + pgi = di \quad \forall i \in N \tag{2}$$

$$fi,j = vi\, vj(\theta i - \theta j) \,/\, xi,j \;\; \forall i,j \in L \tag{3}$$

$$|fi,j| \leq f_{i,j}^{max}, \;\; \forall i,j \in L \tag{4}$$

$$P_{gi}^{min} \leq P_i^G \leq P_{gi}^{max} \quad \forall i \in N \tag{5}$$

$$\theta_i^{min} \leq \theta i \leq \theta_i^{max} \quad \forall i \in N \tag{6}$$

Equation (1) formulates the objective functions aimed at minimizing the total generation cost. This equation is subject to constraints. Equation (2) imposes the nodal balance, considering the incoming and outgoing power flows in the nodal power balance (fj.i denotes the power flow entering node i from node j), simply th opposite of the outgoing flow fi,j. Subsequently, equation (3) represents the power flow through the transmission lines. Equation (4) imposes the corresponding upper limit on the line power flows. Equation (5) determines the maximum generation capacity of each unit, and finally, equation (6) restricts the voltage angle to the permissible range.

To implement case 3, in which system losses are implemented, the DC model with losses is applied.

$$\min z = \sum_{i \in N} Ci * pgi \tag{7}$$

$s.a$

$$\sum_{i \in N} LFgi * pgi - \sum_{i \in N} LFdi * di = PL + Offset \tag{8}$$

$$\sum_{i,j \in L} fi,j - \sum_{j,i \in L} fj,i + pgi = di + PL \quad \forall i \in N \tag{9}$$

$$fi,j = vi\, vj(\theta i - \theta j) \,/\, xi,j \;\; \forall i,j \in L \tag{10}$$

$$|fi,j| \leq f_{i,j}^{max}, \;\; \forall i,j \in L \tag{11}$$

$$P_{gi}^{min} \leq P_i^G \leq P_{gi}^{max} \quad \forall i \in N \tag{12}$$

$$\theta_i^{min} \leq \theta i \leq \theta_i^{max} \quad \forall i \in N \tag{13}$$

Equation (8) represents overall system balance, in which total generation and demand are adjusted using loss factors, so that their difference is equivalent to the system losses (LP) plus a compensation term. In this formulation, Pl represents the total transmission losses and incorporates their effect on the overall power balance. Because the lost factors are obtained through linear approximations, discrepancies arise between generation, demand, and estimated losses. Therefore, the OFFSET parameter is applied to correct these discrepancies, thus ensuring the exact closure of the power balance constraint in the DC model with losses. Finally, equation (9) ensures power balance and the nodal level, requiring that at each node the sum of line flows and local generation equals demand, assigning the absorption of total system losses to the reference node.

3. Procedure for obtaining nodal prices in python software using PYOMO and the GLPK solver

3.1. Electrical Power System

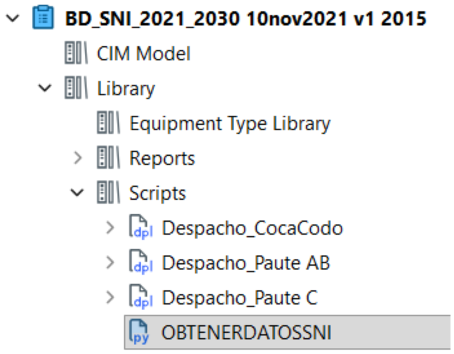
The electrical system under study is the National Interconnected System (SIN). The system is modeled using the Power Factory DIgSILENT simulation software. This data is crucial, as it provides the necessary input for the optimization model, which is then used to calculate nodal prices. The analysis is based on the

2025 case study, considering a peak demand scenario. This scenario includes 181 transmission lines and 191 busbars.

3.2. Data Extraction by Python application.

Given the nature of this electrical system, which models the National Interconnected System, manually extracting the necessary data for the database is complex. Therefore, Python programming software is used. Specifically, a Python script, as shown in Figure 1, must be created within the case study's libraries to automatically extract data using Excel paths. This data will then be chronologically organized in a .dat file. It is important to note that the data should be extracted from the SNI Zone. Extracting data from the entire case study, including the Santo Domingo Zone, Quito Zone, Cuenca Zone, and others, will result in data discrepancies due to the lack of connections between lines and busbars.

Figure 1: *Implementation of the Script for Data Extraction in Python Format.*



3.3. Convert the entire system to per unit and perform the base changes

Once the system data is obtained, it is advisable to normalize all systems parameters to a common basis using the per-unit (p.u.) system. For input into the Python software, this process must be performed correctly, respecting the electrical system data. Due to the amount of data, the process can be carried out in Python or using Excel, simplifying data management. The conversion is performed using equation (15), which must adhere to the power system basis.

$$Value \text{ in } p.u. = \frac{Real\ Value}{Base\ Value} \tag{14}$$

For this purpose, a base power must be established for the entire system, in this case which is Sbase = 100 MVA, because it is the default value used in the DIgSILENT software, however, the base voltage is determined by the nominal voltages of the lines and transformers.

Therefore, the $\boldsymbol{Z_{base}}$ is determined according to equation (15), necessary to convert the values of the lines to p.u.

Equation (16) shows the value obtained for $\boldsymbol{Z_{base}}$ for a 500 kV voltage level, which is operated by the line L_INGA_SRAFA_3_1.

Equation (17) shows the value obtained for $\boldsymbol{Z_{base}}$ for a voltaje level of 230 kV, which is operated by the line L_PIMA_POMA_2_1.

$$Z_{base} = \frac{{V_{base}}^2}{S_{base}} \tag{15}$$

$$Z_{base} = \frac{500kV^2}{100MVA} = 2500 \tag{16}$$

$$Z_{base} = \frac{230kV^2}{100MVA} = 529 \tag{17}$$

Once the $\boldsymbol{Z_{base}}$ value is obtained for each voltaje level, it is easy to find the p.u.values of the lines by dividing the actual value in Ω by the base value.

The transformers exhibit X1 values in p.u., which are specified in their machine nominal bases. Therefore, it is necessary to readjust these values to the selected system base, in this case 100 MVA. This adjustment aims to ensure that the parameters are consistent. The base change is performed using equation (18)

$$Z_{p.u\,nueva} = Z_{p.u\,antigua} * \left(\frac{S_{base,nueva}}{S_{base,antigua}}\right) \tag{18}$$

3.4. Generator costs

One of the main inputs for obtaining the LMPs is the cost of generators, since, based on these costs and line and generator limits, dispatch and the determination of nodal prices will be carried out.

The costs of thermal and hydroelectric power generators in Ecuador are obtained from two databases, in CVS and TXT formats respectively. These prices serve as an Internationally recognized benchmark.

To determine the prices at the busbars, an analysis of the generators connected to the busbar must be carried out, determining the respective value, which is why Table 1 presents 3 costs of the 191 existing busbars.

Table 1: *Costs in the SNI busbars, 5 values.*

Busbar	Cost
B_Manta_13.8_ATM	65
B_Alluriquin_U1_13.8	118.076
B_Baba_69	205.155

3.5. Building the database (.dat) to feed the model)

First, in the .txt file, the slack bus must be defined as a parameter. Regarding the bus parameters, the data is divided into five columns: the first defines the bus number, the second defines the demand at that bus, the third defines the maximum power (in this case, generation), the fourth defines the coast at the bus, and finally, the maximum angle. This must be done for each bus in the power system, ensuring the data is correctly organized. Table 2 shows an example of the first five buses in the electrical system and how their parameters are defined.

Table 2: *Definition of the parameters corresponding to the busbars.*

nb	dem	pmax	cost	anmax:
1	0	0.139	65	3.34
2	0.0116	0	118.076	1.77
3	0	0.039	0	1.04
4	0	0.03	0	1.04
5	0	0.35	6.95	3.08

Finally, to define the lines, there are three columns. The first column contains two pieces of data: the starting point of the line and the ending point in terms of connection to the busbars. The second column contains the line's reactance, and finally, the third column contains the line's maximum flux. Table 3 shows an example of the five lines of the electrical system and how their parameters are defined.

Table 3: *Definition of the parameters corresponding to the transmission lines.*

nl	reac	fmax:
1 2	0.00215	0.541
2 3	0.1243512	0.478
6 5	0.112278	0.23
4 6	0.185567	0.276
6 7	0.104143	0.416

3.6. Building the Python model using Pyomo and the GLPK solver

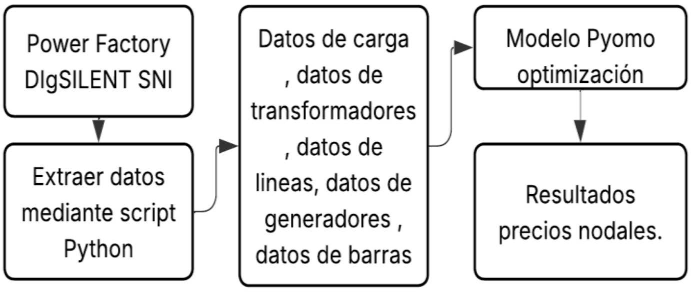
The problem is formulated as an optimal DC power flow (DC-OPF) using the Pyomo library, which allows representing the behavior of Ecuador's National Interconnected System (SNI) under a generation cost minimization approach, considering physical network constraints.

The model is defined as an AbstractModel, which allows the mathematical formulation to be separated from the system data, which are subsequently loaded form a .dat file.

3.6.1. Implemented Model Process

Figure 2 shows the process followed by the method, starting with the extraction of data from the DIgSILENT software, continuing with the construction of the optimization model, and finally obtaining the nodal prices.

Figure 2: *Flowchart of the implemented model.*



4. Result analysis

4.1. Case 1.

In case 1, Ecuador's National Interconnected System (SIN) was modelled assuming infinite transmission capacity on all lines of the network. Therefore, any type of congestion is eliminated, reducing the problem to a purely economic dispatch, where generation is allocated based on the marginal costs of the generators. The problem was solved using a linear DC-OPF solution with the GLPK solver, yielding an optimal feasible solution.

Although the lines are considered infinite, the results show that nodal prices are not completely uniform across the system. This is attributed to the presence of very low-cost local generators or zero-cost generation constraints that lead to local dispatch. Therefore, it does not imply congestion, but rather a natural consequence of economic dispatch with multiple marginal bids.

Due to the absence of congestion, the market price depends on the marginal cost of the dominant generator, that is, the one that is not saturated and can offer a margin. Based on the results obtained, the market price Pmarket=35.7 USD/MWh, is observed; this value corresponds to the shadow price obtained from the dual of the optimization model.

The resulting price data shows low values associated with hydroelectric generation ~ 6 USD/MWh, intermediate values of 30 to 45 USD/MWh corresponding to the dominant zone of the system, and high values exceeding 100 USD/MWh corresponding to zones with expensive or isolated generation. This behavior results in a multimodal distribution, which is expected in large-scale systems such as the National Interconnected System.

Figure 3: *Diagram corresponding to the prices obtained for each node of the SNI in case 1.*

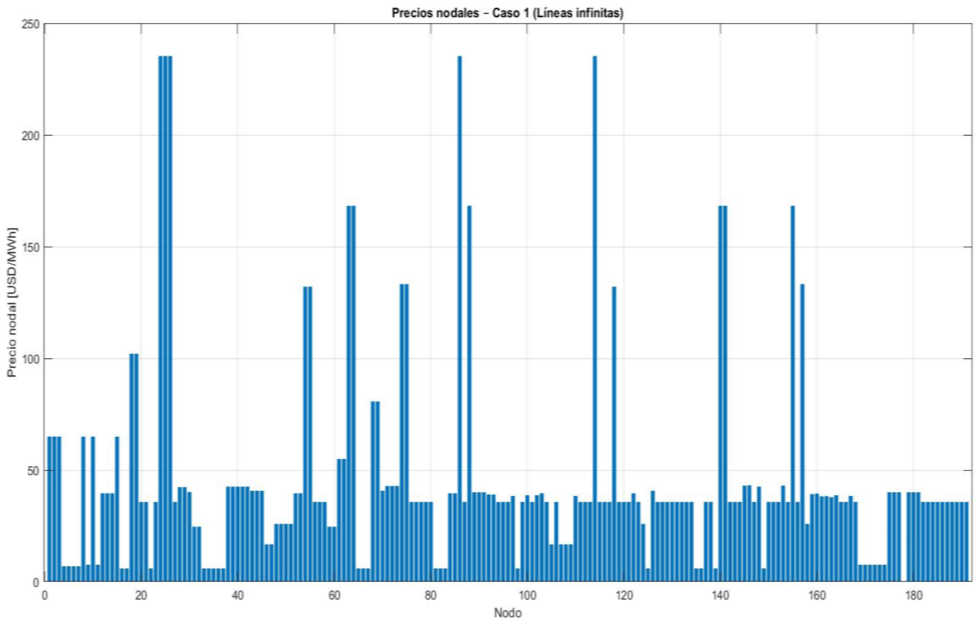
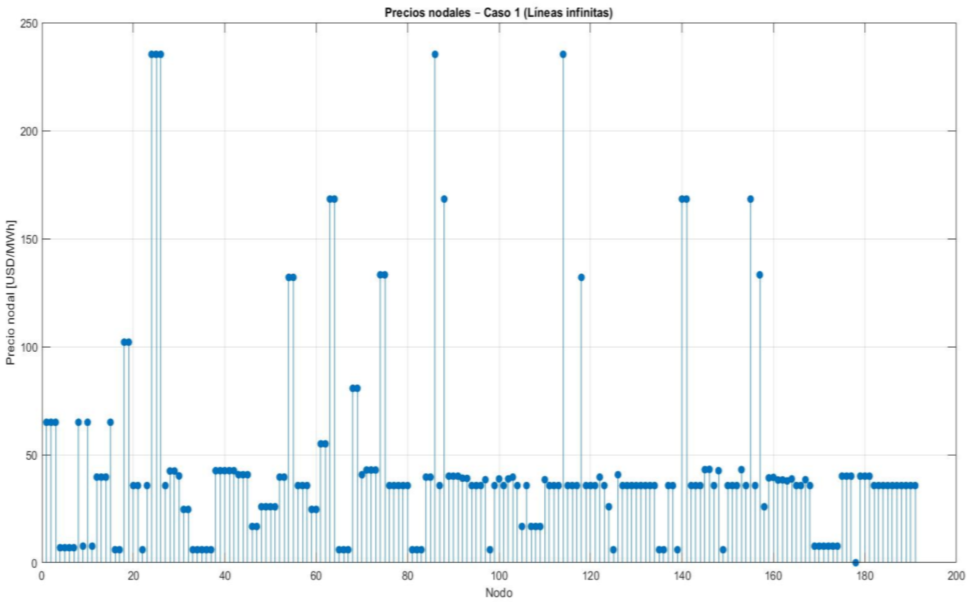
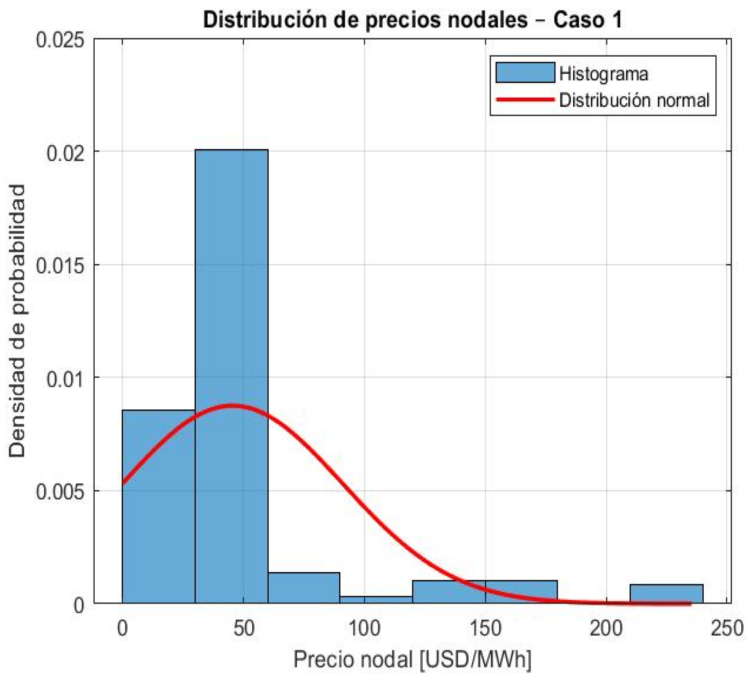


Figure 4: *Diagram corresponding to the prices obtained for each node of the SNI in case 1.*



Figures (3) and (4) show the different nodal prices obtained for case 1, which assumes infinite line capacity. This confirms that the system exhibits significant concentration around the average price, with a moderate coefficient of variation, indicating controlled price dispersion even under unlimited transmission conditions. Furthermore, Figure 5 shows the histogram and normal distribution for case 1.

Figure 5: *Histogram and Normal Distribution of Case 1.*



4.2. Case 2.

In case 2, Ecuador's (SNI) was modelled considering the actual transmission capacities of the lines, as defined in the system model in DIgSILENT Power Factory. Electrical losses are not considered; therefore, the analysis corresponds to a lossless DC-OPF with capacity constraints on the lines. This scenario allows for determining the direct impact of transmission congestion on system nodal prices.

The results show a high dispersion of nodal prices, with values reaching a maximum of 235.3 USD/MWh and multiple intermediate levels associated with different areas of the system. This variability is a clear sign of congestion in the transmission network, which prevents lower-cost generation from supplying the entire system uniformly. The increases in nodal prices, in contrast to case 1, are presented in Table 4. It can be observed how the nodal process rose, thus determining the correct implementation of case 2. Therefore, the values tend to increase in the different nodes of the system, as observed in case study 2.

Table 4: *Nodal prices contrasts in case 1 and case 2*

Node	Case 1	Case 2
12	36.6237	102.0850
13	39.6237	102.0850
14	39.6237	102.0850
20	35.7000	47.8000
56	35.7000	135.4000
89	40.0639	102.0850

Nodes with low prices between 6 and 8 USD/MWh are mainly located in areas near hydroelectric plants or low marginal cost generators, suggesting an adequate local generation availability. However, due to line limitations, energy cannot be transmitted to other parts of the system without violating maximum power flow restrictions on the transmission lines.

Figures (6) and (7) show the different nodal prices obtained for case 2, which considers the actual line capacities. Therefore, when comparing with figures (3) and (4), a significant increase in the prices of some nodes is evident. This is attributed to compliance with the maximum flow rates that must occur on the transmission lines.

Figure 6: *Diagram belonged to prices obtained for each node SIN in case 2.*

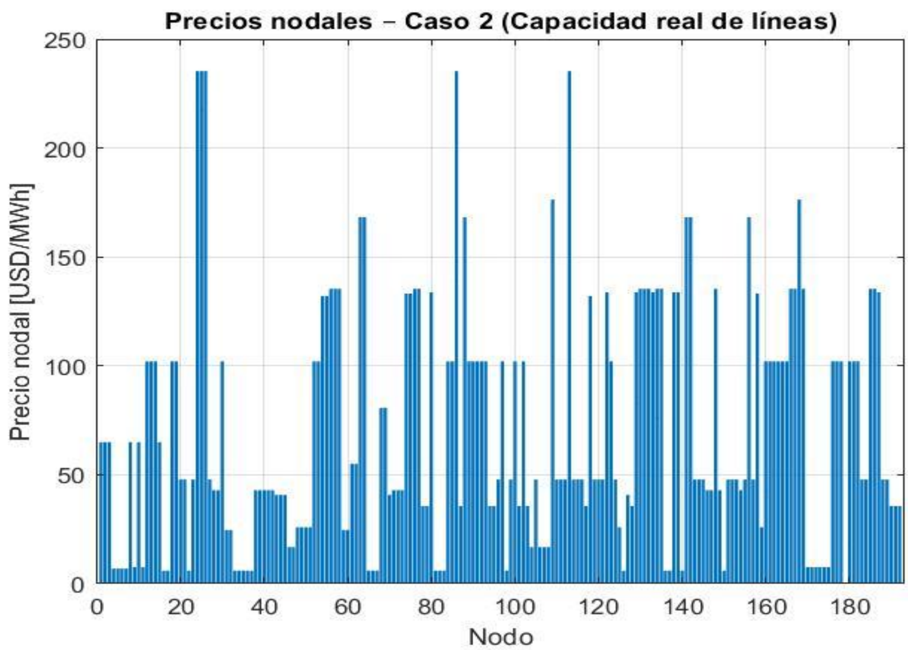
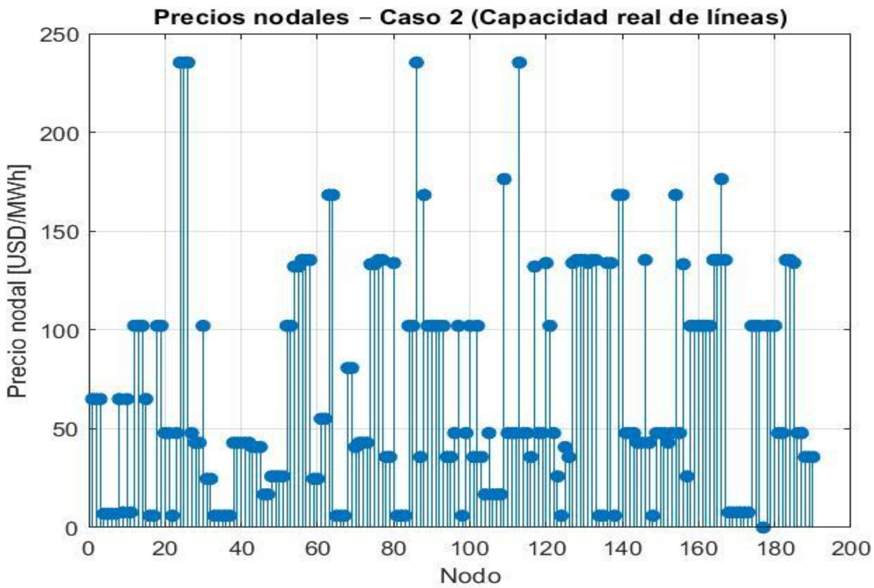
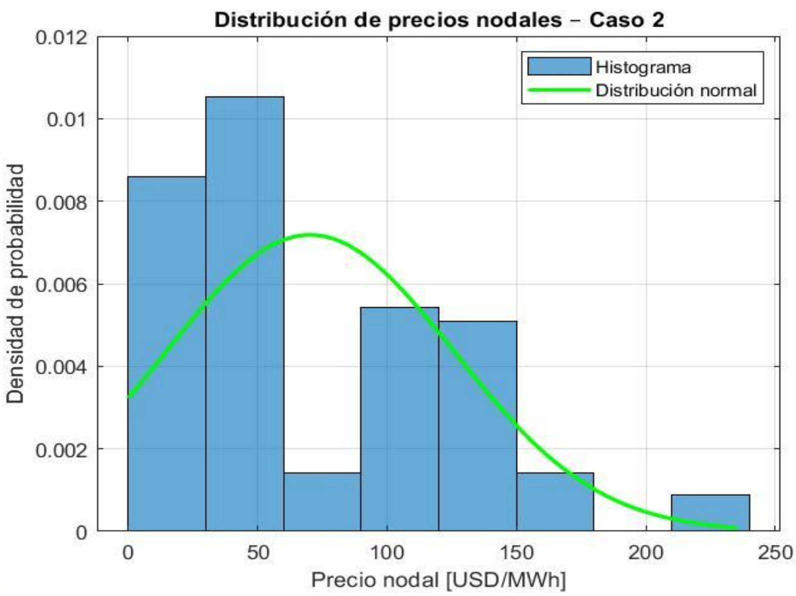


Figure 7: *Diagram belonged to prices obtained for each node SIN in case 2.*



Furthermore, Figure 8 shows the histogram and normal distribution for case 2. It shows an asymmetrical distribution, with a pronounced right tail, characteristic of congested electrical systems.

Figure 8: *Histogram and Normal Distribution from case 2.*



4.3. Case 3.

In case 3 of this study, the nodal prices are obtained considering the real flows of the system and including losses. This case study is more complex to implement because different parameters must be included, and the solver must be changed to achieve optimization, thus minimizing costs for the buses

The new parameter to be considered in the present case study is the resistance in per unit, which must be correctly extracted from the DIgSilent software for each of the system lines.

The implemented procedure is found in the study; this process begins with obtaining the line-node incidence matrix, which will be used to obtain the distribution factor.

To determine both the line-node incidence matrix and the Y-transfer matrix, a Python code was applied, which extracts the data from an Excel file containing the information necessary for the study. The code then generates the incidence matrix considering the line-node connections, defining 1 as the bus to which the flow originates. -1 as the bus to which the power flow arrives, and 0 if there is no connection. Furthermore, the Y-transfer matrix is generated by extracting the reactance of lines i-j, which form the diagonal. Once both matrices are obtained, equation (20) is used to calculate the distribution factors.

$$Hi,m = \gamma * A * (A^T * \gamma * A)^{-1} \tag{20}$$

Then by applying equation (21), the LF loss factors can be obtained.

$$\frac{dLm}{dpgi} = 2\left(\sum_{m\epsilon\iota} Rm\, fm\, Hi,m\right) \tag{21}$$

Loss factors make it easy to determine the offset, which which considers the actual AC losses of the base case, which correspond to 38.1 MW. The code calculates the difference between the generated and demand power, multiplies it by the loss factor obtained for each bus. Finally, it subtracts the product of the power and the LF (Lower Line Factor) at each bus from the system loss factor, thus obtaining and offset of 36.73MW.

Finally, it is necessary to stablish new conditions in the code for obtaining nodal prices, which are determined by equations (22) and (23).

$$\sum_{i\in N} LFgi * pgi - \sum_{i\in N} LFdi * di = PL + Offset \tag{22}$$

$$\sum_{i,j\in L} fi,j - \sum_{j,i\in L} fj,i + pgi = di + PL \quad \forall i \in N \tag{23}$$

In the third case study, after implementing the loss factors and the OFFSET implementation, values are obtained that are accordance with the real prices of the SNI bars; these values are presented in figures (9) and (10)

Figure 9: *Diagram belonged to the prices obtained for each node of the SNI in case 3*

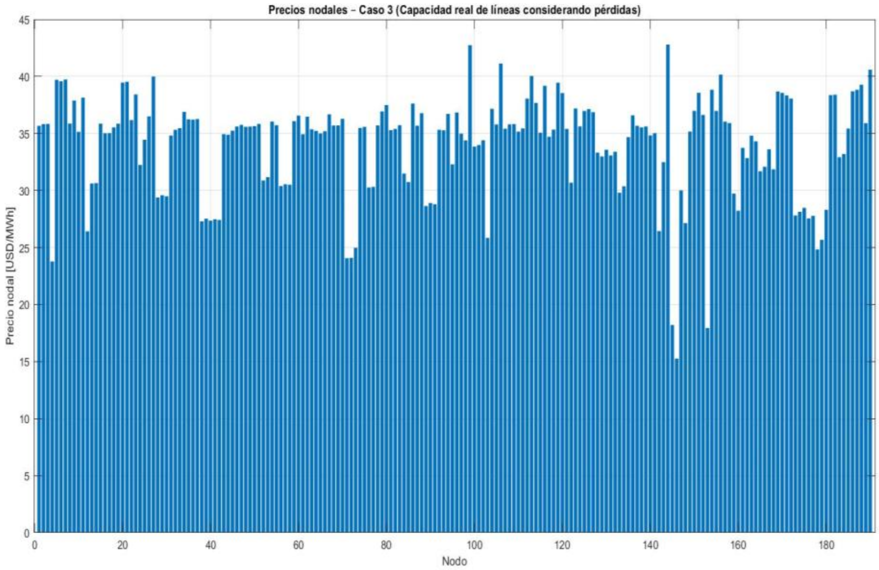
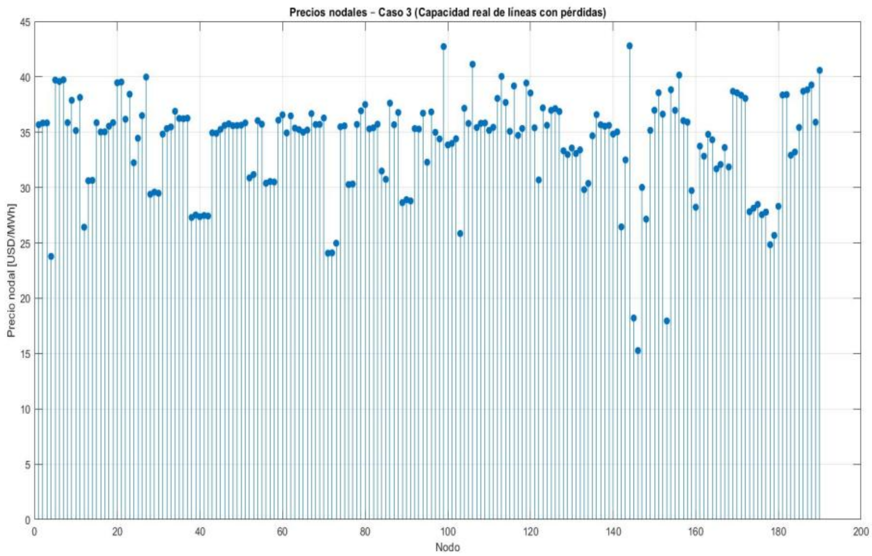


Figure 10: *Diagram corresponding to the prices obtained for each node of the SNI in case 3.*



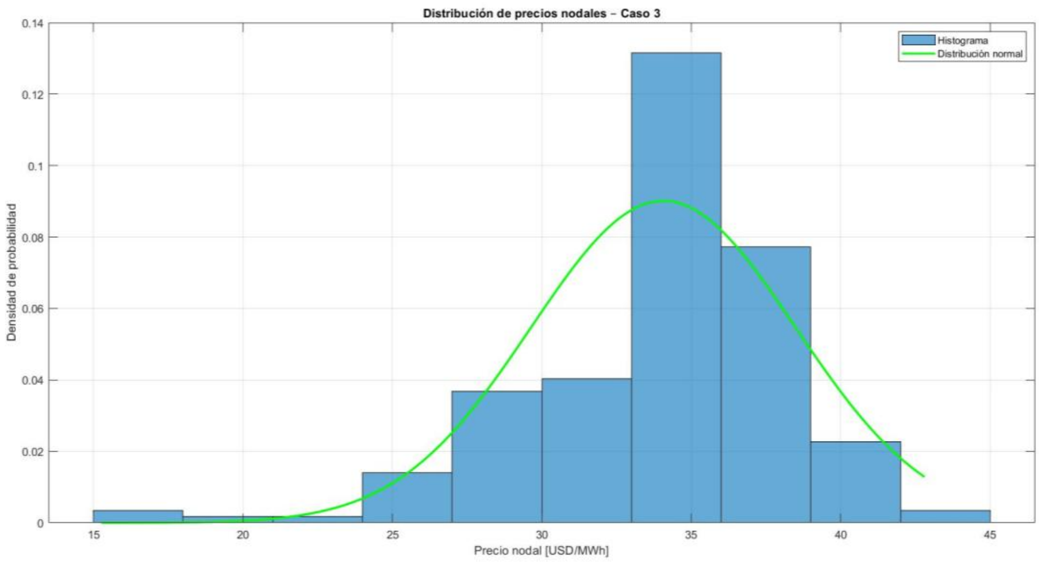
Based on the results obtained, it can be observed that nodal prices have an approximate range between 15 and 43 USD/MWh, with a majority of concentration around 34-36 USD/MWh. Figure 10 shows that, although there is a dominant average value. There are no single prices, which confirms the influence of the transmission systems and losses on price transformation.

It was determined that the busbars with highest nodal prices are primarily associated with areas far from major hydroelectric generation centers, and sectors where energy must travel long distances through the transmission line. Within the context of the National Interconnected System (SNI), these prices reflect the higher cost of supplying an additional unit power, since meeting the increased demand at these nodes implies growth in both generation and system losses.

While the busbars with the lowest nodal prices generally correspond to areas near large power plants and sectors with a lower marginal impact from losses. At these busbars, the marginal cost of supplying additional demand is lower, resulting in reduced nodal prices.

Figure 11 shows the nodal Price histogram, which shows an approximately normal distribution, with a maximum frequency around the system average price, moderate dispersion, and extreme values representing nodes with particular congestions conditions or high losses

Figure 11: *Histogram and Normal Distribution of case 3.*



4.4. Statistical Indicators Analysis.

Table 5: *Statistical Indicators for the study cases*

Indicator	Case 1	Case 2	Case 3
Mean USD/MWh	45.48	70.27	34.06
Median USD/MWh	35.70	47.80	35.38
Standard Deviation	45.57	55.55	4.43
Coefficient of variation	1.002	0.7905	0.13

To evaluate the impact of the transmission network and losses on the formation of nodal prices of the National Interconnected System of Ecuador, three progressive scenarios were analyzed, for which the nodal prices obtained in the 191 bars of the system were evaluated, calculating statistical indicators such as the mean, median and standard deviation.

Case 1, which assumes infinite capacity in the transmission lines, shows a mean of 45.48 USD/MWh and a median of 35.70 USD/MWh, accomplished by a high standard deviation of 45.57 and a coefficient of variation close to 1.002. Due to this behavior, a high relative dispersion of prices is determined. This case does not fully represent the reality of the National Interconnected System (SNI), but it serves as a basis for evaluation the progressive impact of actual line flows and losses.

In case 2, the actual transmission capacities of the SNI are incorporated, the statistical results show an increase in the average values, with a mean of 70.27 USD/MWh and a median of 47.80 USD/MWh, as well as a standard deviation of 55.55 and a coefficient of variation of 0.7905. These values indicate a high price dispersion, associated with the appearance of congestions in the transmission network.

Finally, case 3 represents the most realistic scenario, as it considers both the actual flows on the lines and system losses. In this case, the statistical indicators show a different behavior, with a mean of 34.06 USD/MWh, a median of 35.38 USD/MWh, a standard deviation of 4.43, and a coefficient of variation of 0.13. These values exhibit greater consistency. It is determined that the inclusion of losses smooths out the extreme differences observed in the previously study cases, reflecting a more balanced representation of the actual behavior of the National Interconnected System (SNI). Therefore, it is determined that the model with losses adequately captures the real behavior of the national interconnected system, obtaining consistent and accurate nodal prices in accordance with actual values.

5. Conclusions

When considering transmission lines with a infinite capacity, the electric power system behaves as a perfectly integrated market with no energy transport restriction. Therefore, prices tend to homogenize across most busbars; in this case, the predominant process across most busbars was 35.7 USD/MWh. This presents a theoretical ideal scenario in which the cheapest generators can supply existing demands at the busbars, regardless of the flows through the lines, but without exceeding their generation capacity. This scenario is far removed from the actual operation of Ecuador's National Interconnected System, as it ignores the physical limitations of the network.

The incorporation of actual transmission line capacities revealed significant differences, raising nodal prices at most busbars and thus demonstrating network congestion. Therefore, high nodal prices indicate areas where demand cannot be met with more economical generation due to network limitations, forcing the system to use more expensive local generators, thereby increasing the marginal cost. Based on the above, it is concluded that transmission plays a key role in nodal price formation, as it not only guarantees the operational security of the system but also provides economic signals for the local of new generation.

The determination of nodal prices in Ecuador's National Interconnected System, considering the actual line capacity, real power flows and system losses, yielded values consistent with the system's actual physical. However, the results also demonstrate the inclusion of losses, disrupting price uniformity and generating differences in nodal values due to the higher marginal cost of meeting demand and nodes far from major generation centres or with a greater marginal loss. In conclusion, case 3 demonstrates that the transmission system and the losses play a significant role in nodal price formation. Furthermore, it was determined that implementing mathematical optimization models using the open – source Python software, with solvers such as GLPK and IPOPT, yields consistent values that align with real-world nodal prices. Therefore, the results provide a solid technical foundation for future research, given the models' effectiveness.

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