JURNAL LOCUS: Penelitian & Pengabdian
Volume 5 No. 11 November 2026, pp 10106-10124
E-ISSN 2829-7334
DOI: 10.58344/locus.v5i11.6497

Strategy to Reduce the Main Cost of Electricity Supply in PT PLN Batam

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Keywords:
main cost of electricity supply (BPP); cost volume profit; break-even point; merit order; batam electricity system.

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ABSTRACT

PT PLN Batam recorded a negative operating margin in 2024, as its electricity supply cost (Biaya Pokok Penyediaan, BPP) reached IDR 1,497/kWh, exceeding the average electricity selling price of IDR 1,462/kWh. This condition was primarily attributed to the heavy reliance on natural gas, which accounted for approximately 85% of the fuel mix, rising natural gas prices, and the absence of government subsidies or compensation. This study aimed to identify the primary factors contributing to the high electricity supply cost in the Batam power system and formulate strategies to reduce it. A quantitative case study approach was employed, incorporating cost-volume-profit (CVP) analysis to distinguish fixed and variable costs and determine the break-even point (BEP) for the 2020–2024 period. The analysis was complemented by an examination of the 2024 daily electricity load curve and a merit-order-based generation redispatch simulation. The findings revealed that variable costs, predominantly associated with natural gas consumption, accounted for up to 77.91% of operating expenses, while actual electricity sales in 2024 were 419.35 million kWh below the break-even sales volume. The simulation indicated that increasing the capacity factor of combined-cycle gas turbine (CCGT) power plants while reducing generation from gas engine power plants could lower the BPP to IDR 1,494/kWh, which remained above the average selling price. These findings demonstrated that operational efficiency improvements alone were insufficient to achieve financial sustainability. Therefore, government compensation mechanisms and long-term investments in solar photovoltaic (PV) generation integrated with battery energy storage systems (BESS), or the development of a Sumatra–Batam submarine power transmission cable, were identified as potential strategies for reducing electricity supply costs and improving the financial sustainability of PT PLN Batam.

INTRODUCTION

The development of electricity infrastructure is a strategic priority for addressing the growing demand for electricity in Indonesia. As an essential foundation of socioeconomic activities, reliable electricity infrastructure directly influences public welfare, making equitable, accessible, and sustainable electricity provision crucial for national development. According to PLN's Electricity Supply Business Plan (Rencana Usaha Penyediaan Tenaga Listrik, RUPTL) for 2025–2034, national electricity demand is projected to increase from 323 TWh in 2025 to 511 TWh in 2034, representing an average annual electricity sales growth rate of 5.25%. This expansion is expected to support the government's target of achieving 8%

national economic growth (Ministry of Energy and Mineral Resources, 2025). In Batam, electricity sales are projected to grow by 10.69% under the moderate scenario and 17% under the high-growth scenario during 2025–2034. Driven particularly by increasing demand from data centers, net peak electricity demand is projected to increase from 860 MW in 2025 to 1,988 MW in 2034 under the moderate scenario and from 1,110 MW to 2,902 MW under the high-growth scenario. Meeting these requirements is expected to necessitate additional installed generation and supply capacity of 4,354 MW and 5,874 MW, respectively, through a combination of solar photovoltaic, natural gas-fired, hydropower, and coal-fired generation, battery energy storage systems (BESS), and electricity interconnections with Sumatra.

PT Pelayanan Listrik Nasional Batam (PLN Batam), a subsidiary of PT PLN (Persero), holds an Electricity Supply Business License (Izin Usaha Penyediaan Tenaga Listrik, IUPTL) covering the Batam, Rempang, and Galang (Barelang) areas and parts of the Riau Islands, pursuant to the Decree of the Minister of Energy and Mineral Resources No. 1221-12/20/600.3/2012. Established on October 3, 2000, PLN Batam operates as a vertically integrated electricity utility, encompassing power generation, transmission, distribution, and electricity sales (PT PLN Batam, 2024). Unlike other PLN operating units, PLN Batam serves a designated electricity business area without receiving subsidies or compensation from the central government. Consequently, increases in electricity production costs must be absorbed through the company's operating revenues, potentially placing pressure on electricity tariffs and financial performance. Since early 2024, increases in the electricity supply cost (Biaya Pokok Penyediaan, BPP), without corresponding adjustments to the average electricity selling price, have resulted in a negative margin between electricity sales revenue and supply costs, indicating that each kilowatt-hour (kWh) sold potentially contributes to financial losses.

As presented in Table 1, the electricity supply cost (BPP) in the Batam power system increased from IDR 1,345/kWh in 2020 to IDR 1,497/kWh in 2024, representing an overall increase of 11.3%, with the largest annual increase of 10.31% occurring between 2023 and 2024. The system had an available supply capacity of 813.92 MW, a peak demand of 675.19 MW, and a reported reserve margin of 20.54%. Of the total electricity supply, 23.97% was generated by PLN Batam's own power plants, while the remaining 76.03% was supplied by independent power producers (IPPs) and leased generation facilities. In 2024, operating expenses increased by 30.32%, substantially exceeding revenue growth of 14.21%. This disparity was primarily attributed to rising natural gas prices. Because the Specific Natural Gas Price (Harga Gas Bumi Tertentu, HGBT) had not been established for PLN Batam's gas supply contracts, most natural gas purchases were subject to commercial pricing. Beginning January 1, 2024, natural gas supplied by PetroChina was priced at USD 6.50 per million British thermal units (MMBtu), compared with USD 4.00/MMBtu in the preceding year. Meanwhile, approximately 18% of the natural gas volume supplied by PT Perusahaan Gas Negara (PGN), which exceeded the HGBT allocation, was priced at USD 11.08/MMBtu during January–February 2024 and USD 9.49/MMBtu beginning in March 2024. Furthermore, the company's 2024 Work Plan and Budget (Rencana Kerja dan Anggaran Perusahaan, RKAP) assumed an exchange rate of IDR 15,000 per USD, whereas the exchange rate recorded on December 31, 2024, reached IDR 15,850 per USD. This depreciation of IDR 850 per USD further increased

primary energy procurement costs, particularly for natural gas contracts denominated in US dollars.

Table 1. BPP, Average Selling Price, and Primary Energy Prices of the Batam System, 2020–2024

Year	BPP (Rp/kWh)	Average Selling Price (Rp/kWh)	Gas Price (USD/MMBTU)	Coal (metric ton, as reported)
2020	1,345	1,429	5.99	735,175
2021	1,297	1,436	5.49	807,349
2022	1,331	1,419	5.50	972,069
2023	1,357	1,419	5.45	1,051,000
2024	1,497	1,462	6.35	1,038,194

Source: Internal data and PT PLN Batam Annual Report 2020–2024 (PT PLN Batam, 2024)

As presented in Table 1, the average electricity selling price remained relatively stable, ranging from IDR 1,419/kWh to IDR 1,462/kWh during the observation period, whereas the electricity supply cost (Biaya Pokok Penyediaan, BPP) increased sharply in 2024, primarily due to rising natural gas prices. In 2023, PT PLN Batam recorded a profit of approximately IDR 157 billion from electricity sales in Batam. However, in 2024, the BPP exceeded the average selling price, resulting in a loss of approximately IDR 124 billion. PLN Batam implemented a tariff adjustment of 1.43% in the second half of 2025, which applied only to certain high-income residential customers, government customers, and special service customers. Each increase of IDR 1/kWh in the average electricity selling price was estimated to generate additional revenue of approximately IDR 3.3 billion in 2023 and IDR 3.6 billion in 2024. Nevertheless, electricity tariff adjustments were not necessarily the preferred solution because of their potential implications for economic competitiveness and regional economic growth. Therefore, reducing the BPP became an urgent strategic priority for improving the company's financial performance and ensuring the long-term sustainability of electricity supply.

The challenge of high electricity generation costs resulting from dependence on natural gas and the absence of government subsidies is also relevant to other island-based electricity systems in Indonesia. Bali provides a useful comparative case because its electricity system operates within a geographically distinct island region and faces comparable challenges related to energy supply reliability, generation costs, and infrastructure development, as presented in Table 2.

Table 2. Comparison of the Batam and Bali Electricity Systems, 2024

Item	Batam	Bali
Island area (km²)	3,869	5,780
Population (people)	1,300,281	4,461,300
Population density (people/km²)	336	757
Electricity customers	382,939	1,796,683
Main livelihood	Manufacturing, shipbuilding, free trade, logistics services, tourism	Agriculture, plantations, tourism, hotels, restaurants, transportation, fisheries, livestock, handicrafts, trade

Item	Batam	Bali
Capacity (MW)	807.1	1,187
Peak load (MW)	690	1,388
Load factor (%)	62.25	27.44
Electrical system	Isolated system	Interconnection system
Submarine cable	Available (Batam–Bintan)	Available (Java–Bali)
Generation mix	PLTMG 36.76%, PLTG 22.20%, PLTGU 17.75%, PLTU 14.06%, PLTD 9.09%, PLTS 0.10%	PLTG 38.18%, PLTU 25.60%, submarine cable 24.04%, PLTDG 12.19%
BPP (Rp/kWh)	1,497	1,565
Average selling price (Rp/kWh)	1,462	1,768

Source: PLN Statistical Report 2024 (PT PLN (Persero), 2024); Central Statistics Agency; internal data

As presented in Table 2, Batam has a smaller land area than Bali, limiting the availability of suitable sites for renewable energy development and contributing to its substantial dependence on natural gas supplied at market-based prices. Gas-fired power plants, including gas turbine power plants (Pembangkit Listrik Tenaga Gas, PLTG), gas engine power plants (Pembangkit Listrik Tenaga Mesin Gas, PLTMG), and combined-cycle gas turbine power plants (Pembangkit Listrik Tenaga Gas dan Uap, PLTGU), account for 76.71% of Batam's electricity generation mix. In contrast, gas-fired power plants, including PLTG and gas-fired diesel engine power plants (PLTDG), account for 50.37% of Bali's electricity supply mix, while approximately half of its electricity supply is provided through submarine power interconnections and coal-fired power plants. Bali's interconnection with the Java electricity system through a 150-kV submarine transmission cable enables access to electricity generated by lower-cost power plants. Consequently, Bali recorded an average electricity selling price of IDR 1,768/kWh, exceeding its electricity supply cost (Biaya Pokok Penyediaan, BPP) of IDR 1,565/kWh, whereas Batam's average electricity selling price remained below its BPP.

From an economic perspective, electricity supply costs are influenced by decisions regarding the construction of new power plants, the replacement of aging generating units, and the extension of existing plants' operational lifetimes. These costs generally comprise fixed costs, including capital investment, financing costs, and depreciation, and operating costs, with fuel representing the largest expense for thermal power plants, followed by labor, maintenance, repairs, consumables, supervision, and taxes (Raja et al., 2006). Kehlhofer et al. (2009) distinguish between variable costs, including fuel and output-dependent operation and maintenance expenses, and fixed costs, including routine operation and maintenance, administration, financing costs, and depreciation. In electricity generation cost accounting, expenses are commonly categorized into Component A, covering capital-related costs such as investment recovery, depreciation, interest, taxes, and insurance; Component B, covering fixed operation and maintenance costs, including personnel and routine maintenance; Component C, representing fuel costs; and Component D, covering variable operation and maintenance expenses, including lubricants and consumables. Electricity system interconnections can improve supply reliability and facilitate electricity transfers from lower-cost generating systems to higher-cost systems, thereby potentially reducing overall electricity supply costs

(Purvin et al., 2018). Because electricity generation must continuously balance electricity demand, accurate load forecasting is essential for planning generation schedules across annual, weekly, and daily time horizons (Stephen & Patrick, 2009). Based on annual operating duration, electricity demand can be classified into baseload, typically supplied by power plants operating for more than 5,000 hours annually with a capacity factor (CF) exceeding 57%; intermediate load, generally supplied by plants operating at CFs of approximately 23–57%; and peak load, typically supplied by plants operating for fewer than 2,000 hours annually with CFs below 23% (Nag, 2008). A higher utilization rate enables fixed generation costs to be distributed across a greater volume of electricity output, potentially reducing the average cost per kilowatt-hour (Daman, 2009; Raja et al., 2006).

In addition to electricity demand characteristics, generation scheduling must account for the operational flexibility and technical constraints of different power generation technologies. These include ramp rates, ramping times, available generation capacity, minimum stable operating levels, minimum operating times, no-load costs, and startup and shutdown costs (Nalbandian & Sugden, 2016). Power plants characterized by slower ramp rates and longer minimum operating periods are generally more suitable for supplying baseload demand, whereas highly flexible generating units with shorter startup and ramping times are better suited to meeting peak demand and responding to rapid load fluctuations, despite potentially higher operating costs. These operational characteristics and their implications for generation scheduling are summarized in Table 3.

Table 3. Ramp Time and Minimum Run-Time by Power Plant Technology

Technology	Ramp Time	Minimum Run-Time
Simple cycle combustion turbine	Minutes to hours	Minutes
Combined cycle combustion turbine	Hours	Hours to days
Nuclear	Days	Weeks to months
Wind turbine (includes off-shore wind)	Minutes	None
Hydroelectric (includes pumped storage)	Minutes	None

Source: Nalbandian & Sugden (2016)

In the Indonesian context, Arifin (2015) identified a hierarchy of electricity generation costs, with diesel power plants (Pembangkit Listrik Tenaga Diesel, PLTD) generally having the highest generation costs, followed by gas-fired power plants, including gas turbine power plants (Pembangkit Listrik Tenaga Gas, PLTG) and gas engine power plants (Pembangkit Listrik Tenaga Mesin Gas, PLTMG), while coal-fired steam power plants (Pembangkit Listrik Tenaga Uap, PLTU) were among the lowest-cost conventional generation technologies. Accordingly, high-cost generating units should primarily be dispatched during peak demand periods, while baseload demand should be supplied by units with lower marginal generation costs. (Nugroho et al., 2018) demonstrated that power system reconfiguration and optimization of interbus transformer loading could reduce electricity production costs without compromising system reliability, particularly when high-cost gas-fired generating units were not operating. The merit-order principle prioritizes electricity generation sources according to their short-run marginal costs, dispatching lower-cost units before higher-cost alternatives, subject to technical and operational constraints. (Antweiler & Muesgens, 2025) extended this

concept to electricity systems with high renewable energy penetration, highlighting the potential role of energy storage systems in influencing electricity market prices. Similarly, (Thommessen et al., 2025) demonstrated that merit-order-based dispatch strategies prioritizing lower-marginal-cost generation sources could minimize total operating costs. Furthermore, (Cao et al., 2020) showed that price-based demand response mechanisms in integrated multi-energy systems could enhance operational flexibility and reduce daily operating costs.

Cost-volume-profit (CVP) analysis provides a framework for evaluating how changes in operating costs, electricity sales volumes, and selling prices influence profitability. This approach supports managerial decision-making regarding pricing strategies, cost structures, generation portfolios, and production capacity utilization. Its principal components include cost behavior classification, contribution margin analysis, break-even point (BEP) determination, target profit analysis, and margin of safety assessment (Kimmel et al., 2013). Break-even analysis helps identify whether profitability can be improved by reducing variable costs, increasing revenue, or minimizing fixed costs, although increasing electricity selling prices may be constrained by regulatory requirements, customer affordability, and economic competitiveness (Vinturella & Erickson, 2009). CVP analysis can also integrate accounting-based budgetary controls with financial planning models to evaluate operational flexibility and production efficiency (Daniel, 2012). Furthermore, the integration of fuzzy logic into CVP models can accommodate uncertainty in cost and revenue assumptions (Yuan, 2009), while CVP analysis remains an important instrument for profit planning, cost management, and financial loss prevention (Sudaryono et al., 2024). Nevertheless, previous studies have rarely integrated CVP and break-even analyses with electricity load curve assessments and merit-order-based generation dispatch simulations, particularly in the context of unsubsidized island electricity utilities. Addressing this research gap, the present study aimed to identify the primary factors contributing to high electricity supply costs in the Batam power system and formulate alternative operational and strategic measures to reduce the electricity supply cost (Biaya Pokok Penyediaan, BPP) and minimize potential operating losses at PT PLN Batam.

METHOD

This study employed a quantitative case study design to examine the electricity supply costs (Biaya Pokok Penyediaan, BPP) of PT PLN Batam, which exceeded the average electricity selling price. The analytical approach integrated cost-volume-profit (CVP) analysis, electricity system operational analysis, and capital budgeting considerations to evaluate potential long-term investment strategies (Damodaran, 2012, 2015; Stermole, 2000). The study focused on the Batam electricity system managed by PT PLN Batam, encompassing electricity generation, transmission, and distribution, without conducting detailed technical assessments of individual power plants or transmission infrastructure.

Primary data were collected through interviews with PT PLN Batam management and relevant regulatory authorities involved in electricity system planning and operations. The interviews addressed financial performance expectations, electricity market opportunities, technological developments, natural gas procurement costs, global energy price fluctuations, and potential operational improvements. Secondary data included PT PLN Batam's financial statements, electricity tariff data, and annual reports for 2020–2024 (PT PLN Batam, 2024);

the PLN Batam Electricity Supply Business Plan (Rencana Usaha Penyediaan Tenaga Listrik, RUPTL) for 2025–2034 (Ministry of Energy and Mineral Resources, 2025); PLN statistical reports (PT PLN (Persero), 2024); electricity tariff regulations; power balance data; peak load reports; power plant performance monitoring records; and relevant technical project documentation (PT PLN (Persero), n.d.).

The CVP analysis began by classifying operating expenses into fixed costs, including personnel expenses, administrative costs, depreciation, and interest expenses, and variable costs, including electricity purchases from independent power producers (IPPs), power plant leasing expenses, fuel costs, variable operation and maintenance expenses, and transmission, distribution, and tax expenses. Unit costs were calculated by dividing the relevant expenses by the total electricity sales volume in kilowatt-hours (kWh). Contribution margin, net income, break-even point (BEP), and margin of safety were subsequently calculated using the following equations (Kimmel et al., 2013):

The electricity system operational analysis examined the installed and available generation capacity in 2024, average peak demand, capacity factors, electricity generation volumes, operation and maintenance costs, fuel expenditures, and variable generation costs across different power plant technologies. Load factors and capacity factors were calculated to assess generation utilization and operational efficiency (Daman, 2009). Power plants operated by IPPs were assumed to be subject to take-or-pay contractual arrangements, and their capacity factors were therefore held constant throughout the simulation. The average daily electricity load curve for 2024 was used to simulate the redispatch of PLN-owned generating units based on merit-order principles, prioritizing lower-variable-cost generation while considering operational constraints. The potential government compensation requirement was also estimated by applying a 7% profit margin to the difference between operating expenses and electricity sales revenue, based on the company's financial statements.

Long-term strategic alternatives were assessed with reference to the proposed RUPTL for 2025–2034, which included an additional 3,554 MW of generation capacity, comprising 635 MW of solar photovoltaic power plants (Pembangkit Listrik Tenaga Surya, PLTS), supported by 60 MW of battery energy storage systems (BESS), 1,359 MW of combined-cycle gas turbine power plants (Pembangkit Listrik Tenaga Gas dan Uap, PLTGU), and 1,500 MW of gas engine power plants (Pembangkit Listrik Tenaga Mesin Gas, PLTMG). Additional electricity supply was planned through the Sumatra–Batam interconnection, including 1,200 MW of electricity purchases from PT PLN (Persero) and 189 MW from PT PUS. Supporting infrastructure development included 1,080 circuit-kilometers of transmission lines, 6,520 MVA of substation capacity, 3,585 circuit-kilometers of distribution networks, and 652 MVA of distribution transformer capacity. These proposed developments were considered potential long-term measures to improve electricity supply reliability, diversify energy sources, and reduce generation costs. The study's conceptual framework is presented in Table 4.

Table 4. Conceptual Framework of the Study

Stage	Description
Business issue	Negative profitability: BPP (Rp1,497/kWh) exceeds the average selling price (Rp1,462/kWh); root causes are the dominance of gas-fired plants and the absence of subsidies or compensation; future risk arises from uncertainty in fuel prices and exchange rates
Theoretical foundation	Cost Volume Profit (CVP); electricity system and merit order
Data collection	Profit and loss reports of PLN Batam; PLN Statistical Report; RUPTL PLN Batam; Batam peak load report; performance monitoring of Batam system plants; project technical documents (KKP/FS)
Variable and data analysis	Cost structure (fixed cost, variable cost, BEP); system operation (load curve, merit order)
Strategy 1 (short term)	Optimization of existing operation by maximizing low-cost plants and minimizing expensive plants (merit order and CVP)
Strategy 2 (long term)	New infrastructure development: Sumatra–Batam subsea cable versus PLTS and BESS
End goal	Decrease in BPP and increase in the operating profit margin of PT PLN Batam

Source: Authors

RESULTS AND DISCUSSION

Cost Structure and Operating Performance, 2020–2024

The income statement of PT PLN Batam consists of operating revenue (electricity sales by customer category, customer connections, and other revenue) and operating expenses, which were classified into variable and fixed costs as presented in Table 5.

Table 5. Condensed Income Statement of PT PLN Batam, 2020–2024 (Rp billion)

Description	2020	2021	2022	2023	2024
Operating revenue	**3,494.95**	**3,708.41**	**4,208.23**	**4,553.57**	**5,246.70**
Electricity sales	3,490.42	3,684.29	4,175.64	4,553.57	5,246.70
Customer connection and other	4.53	24.12	32.59	–	–
Operating expenses	**3,312.47**	**3,488.68**	**4,000.59**	**4,396.28**	**5,370.82**
Variable cost	**2,304.34**	**2,448.68**	**2,988.36**	**3,328.71**	**4,184.66**
Electricity purchase (IPP)	–	–	3.48	7.34	1.37
Generator rental	166.12	228.78	255.84	272.03	273.17
Operation and maintenance	274.08	307.04	367.77	443.85	554.39
Fuel	1,793.09	1,784.74	2,235.84	2,492.78	3,299.18
PLTU	302.94	363.83	464.21	484.80	472.87
PLTG	183.86	243.96	284.54	308.81	332.36
PLTGU	1,182.16	1,040.49	1,156.08	1,118.80	1,343.72
PLTD	0.90	13.33	53.77	38.19	14.61
PLTMG	123.23	123.13	277.24	542.19	1,135.63
Transmission function	35.65	39.99	47.63	57.52	72.36
Distribution function	8.97	10.07	11.99	14.48	18.21
Tax expense	26.42	78.06	65.81	40.71	(34.03)
Fixed cost	**1,008.14**	**1,040.00**	**1,012.23**	**1,067.57**	**1,186.16**
Personnel	139.79	149.60	167.65	229.83	234.32
Administration	80.48	67.61	80.79	111.10	111.19
Depreciation of fixed assets	307.86	305.35	366.17	404.12	536.63

Description	2020	2021	2022	2023	2024
Interest expense	480.00	517.44	397.61	322.52	304.02

Source: PT PLN Batam Financial Statements 2020–2024 (processed)

Table 5 shows that operating expenses increased by 23% in 2024 compared with 2023, more than double the 11% increase recorded in the previous year. This increase was driven mainly by a 32.3% rise in fuel costs. Variable costs increased moderately in 2021, surged by 23.3% in 2022 owing to greater use of gas and coal and the operation of diesel plants to replace units under maintenance, rose by 12.5% in 2023, and jumped by 27.3% in 2024. The 2024 spike was triggered by the absence of HGBT pricing, which forced PLN Batam to buy gas at commercial prices, while electricity demand also increased by 11.79%. The fuel cost of PLTMG alone more than doubled from Rp542.19 billion in 2023 to Rp1,135.63 billion in 2024. Among fixed costs, personnel costs rose most sharply in 2023 (37.1%) due to workforce expansion, administrative expenses increased by 37.5% in the same year, and depreciation grew in line with the addition of new plants and infrastructure, so total fixed costs increased by 5.5% in 2023 and 11.1% in 2024.

Electricity Production and Sales

The installed capacity of the Batam system increased from 625.75 MW in 2020 to 925.59 MW in 2024, consisting of 221.67 MW of PLN-owned plants (PLTD 59.13 MW, PLTGU 135.29 MW, PLTMG 26.25 MW, and PLTS 1 MW) and 703.92 MW of non-PLN capacity (leased PLTMG 250 MW, leased PLTD 25 MW, IPP PLTG 70 MW, IPP PLTGU 164.20 MW, IPP PLTMG 64.72 MW, and IPP PLTU 130 MW). The growth of capacity was driven by the increasing number of customers and rising demand. Table 6 presents electricity production by source together with electricity sold and the number of customers.

Table 6. Electricity Production, Sales, and Customers of the Batam System, 2020–2024

Description	2020	2021	2022	2023	2024
PLN plants (million kWh)	**970.93**	**940.48**	**1,071.98**	**1,096.01**	**970.20**
PLTD	0.61	8.80	26.67	16.85	1.77
PLTGU	873.45	824.05	904.64	944.25	850.38
PLTMG	96.86	107.63	140.67	133.57	116.78
PLTS	–	–	–	1.35	1.26
Non-PLN plants (million kWh)	**2,077.77**	**2,274.29**	**2,371.76**	**2,885.28**	**3,461.19**
Leased PLTD	–	–	–	1.84	3.73
Leased PLTMG	–	–	9.93	320.60	976.09
IPP PLTGU	256.93	1,177.00	1,083.51	1,144.34	1,149.65
IPP PLTMG	81.87	91.08	295.82	359.95	349.22
IPP PLTG	1,072.96	271.88	263.81	328.28	279.28
IPP PLTU	666.02	734.32	718.70	730.28	703.21
Total production (million kWh)	**3,048.70**	**3,214.77**	**3,443.74**	**3,981.29**	**4,431.39**
Total electricity sold (million kWh)	**2,443.25**	**2,565.79**	**2,943.17**	**3,209.79**	**3,588.24**
Number of customers	**336,878**	**347,614**	**357,673**	**368,739**	**380,348**

Source: PLN Statistics 2020–2024 (PT PLN (Persero), 2024)

Table 6 reveals a significant reliance on external sources. In 2024, about 79% of total supply came from leased plants and IPPs, while PLN-owned plants contributed only about 21%, and the growth in supply over the past five years was largely driven by IPPs and leased plants, particularly leased PLTMG, whose output rose from 9.93 million kWh in 2022 to 976.09 million kWh in 2024. The difference between production and sales reflects own use at generating units and substations as well as losses in transmission and distribution. Revenue from electricity sales increased every year in line with the number of customers and the volume sold, while revenue from customer connections and other sources was irregular and recorded only when new connections or non-routine transactions occurred.

Contribution Margin and Net Income

The contribution margin explains how selling price, sales volume, variable costs, and fixed costs interact in determining net income, which is the difference between the total contribution margin and fixed costs (Kimmel et al., 2013). Table 7 summarizes the unit costs and CVP results.

Table 7. Unit Costs, Contribution Margin, and Net Income, 2020–2024

Description	2020	2021	2022	2023	2024
Electricity sales (Rp billion)	3,490.42	3,684.29	4,175.64	4,553.57	5,246.70
Variable cost (Rp billion)	2,304.34	2,448.68	2,988.36	3,328.71	4,184.66
Fixed cost (Rp billion)	1,008.14	1,040.00	1,012.23	1,067.57	1,186.16
Volume sold (million kWh)	2,443.25	2,565.79	2,943.17	3,209.79	3,588.24
Unit selling price (Rp/kWh)	1,428.60	1,435.93	1,418.76	1,418.65	1,462.19
Unit fixed cost (Rp/kWh)	413	405	344	333	331
Unit variable cost (Rp/kWh)	943.15	954.36	1,015.36	1,037.05	1,166.21
Total contribution margin (Rp billion)	1,186.08	1,235.61	1,187.28	1,224.86	1,062.04
Contribution margin per unit (Rp/kWh)	485.45	481.57	403.40	381.60	295.98
Contribution margin ratio (%)	33.98	33.54	28.43	26.90	20.24
Net income (Rp billion)	177.94	195.61	175.05	157.29	(124.12)

Source: Data processed from PT PLN Batam Financial Statements and PLN Statistics 2020–2024

Table 7 shows that the total contribution margin remained above Rp1,180 billion during 2020–2023 because of strong growth in sales volume, but fell to Rp1,062.04 billion in 2024. The contribution margin per unit declined continuously from Rp485.45/kWh in 2020 to Rp295.98/kWh in 2024, and the contribution margin ratio fell from 33.98% to 20.24%, reflecting the deterioration of cost efficiency due to rising gas prices. The unit variable cost exceeded Rp1,000/kWh for the first time in 2022 and reached Rp1,166.21/kWh in 2024, whereas the unit selling price increased only from Rp1,428.60/kWh to Rp1,462.19/kWh. As a result, net income declined after 2021 and turned into a loss of Rp124.12 billion in 2024, implying that the company should either increase the selling price per unit or reduce variable costs.

Break-Even Analysis

The break-even point (BEP) is the sales volume at which total revenue equals total costs. Table 8 presents the BEP in units and in rupiah for 2020–2024, converted from the annual CVP charts, together with the margin of safety and the profit per unit.

Table 8. Break-Even Point and Margin of Safety of the Batam System, 2020–2024

Year	BEP (kWh)	BEP (Rp billion)	Actual Sales (kWh)	Margin of Safety (kWh)	Profit per Unit (Rp/kWh)
2020	2,076,700,239	2,966.77	2,443,250,000	366,549,761	72.83
2021	2,159,606,893	3,101.04	2,565,790,000	406,183,107	76.24
2022	2,509,230,065	3,559.99	2,943,170,000	433,939,935	59.48
2023	2,797,605,594	3,968.83	3,209,790,000	412,184,406	49.00
2024	4,007,593,802	5,859.87	3,588,240,000	(419,353,802)	(34.59)

Source: Data processed from PT PLN Batam Financial Statements 2020–2024

As shown in Table 8, actual sales exceeded the BEP during 2020–2023 by a margin of safety of only about 366–434 million kWh, which is relatively small compared with the total volume sold. In 2020, the profit per unit of Rp72.83/kWh indicated that the system was operating only slightly above the break-even point, so any pressure on variable costs, which accounted for 69.57% of operating expenses, could directly erode profitability. In 2021, profitability still relied on volume growth rather than cost efficiency. In 2022, the BEP surged by approximately 349.6 million kWh, the largest increase until then, and net income declined despite higher sales volume. In 2023, the profit per unit fell to Rp49.00/kWh, the lowest in three years. In 2024, the BEP rose by approximately 1,209.99 million kWh to 4,007.59 million kWh, far above actual sales of 3,588.24 million kWh, leaving a shortfall of 419.35 million kWh. Total revenue of Rp5,246.70 billion fell short of total cost of Rp5,370.82 billion, and the total cost per unit of Rp1,496.78/kWh exceeded the selling price of Rp1,462.19/kWh. Figure 1 illustrates that in 2024 the total cost and total revenue lines are almost parallel, so every additional kWh sold enlarges the loss.

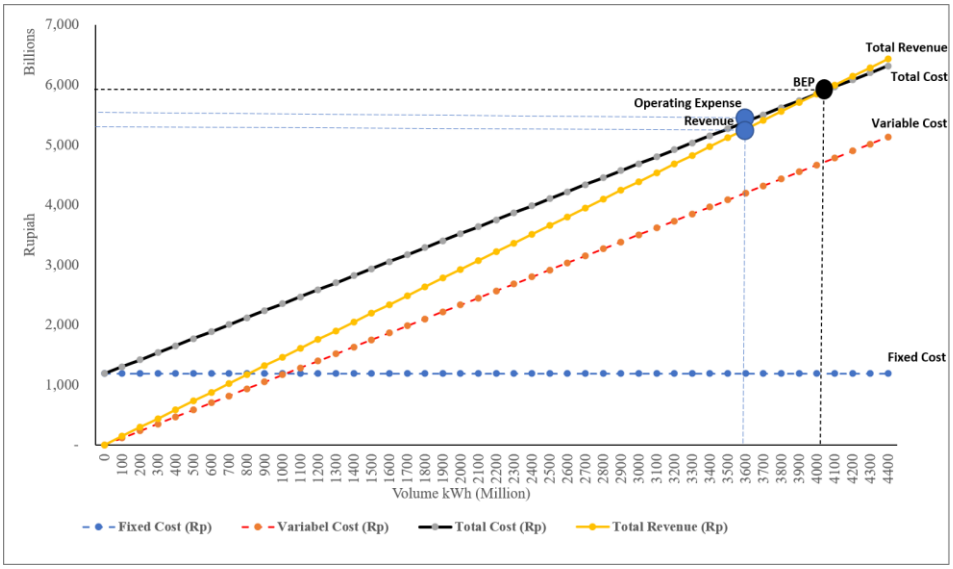


Figure 1. Break-Even Point of the Batam Electricity System, 2024
Source: Data processed from PT PLN Batam Financial Statements 2024

Drivers of the High Main Cost of Electricity Supply

The composition of costs presented in Table 9 explains why the BEP increased so sharply.

Table 9. Composition of Operating Expenses, Variable Costs, and Fuel Mix, 2020–2024 (%)

Component	2020	2021	2022	2023	2024
Share of operating expenses					
Fixed cost	30.43	29.81	25.30	24.28	22.09
Variable cost	69.57	70.19	74.70	75.72	77.91
Share of variable cost					
Purchase of electricity	0.0	0.0	0.1	0.2	0.03
Generator rental	7.2	9.3	8.6	8.2	6.5
Operation and maintenance	11.9	12.5	12.3	13.3	13.2
Fuel	77.8	72.9	74.8	74.9	78.8
Transmission function	1.5	1.6	1.6	1.7	1.7
Distribution function	0.4	0.4	0.4	0.4	0.4
Tax expense	1.1	3.2	2.2	1.2	(0.8)
Fuel mix					
Coal	16.89	20.39	20.76	19.45	14.33
Gas	83.05	78.87	76.83	79.02	85.22
Oil	0.05	0.75	2.40	1.53	0.44

Source: Data processed from PT PLN Batam Financial Statements 2020–2024

Table 9 yields four structural findings. First, variable costs dominate the cost of supply, and their share increased from 69.57% in 2020 to 77.91% in 2024, making the cost structure increasingly sensitive to price fluctuations. Second, fuel is consistently the largest variable cost component, between 72.9% and 78.8% of variable costs, far above operation and maintenance (11.9–13.3%) and plant rental (6.5–9.3%), so fuel price movements directly determine the BPP. Third, gas dominates the fuel mix at more than 76% throughout the period and rose from 79.02% in 2023 to 85.22% in 2024, while the share of coal fell to 14.33%; because gas and oil are more expensive per unit of energy than coal, this shift raised the variable cost per kWh. Fourth, electricity tariffs remained relatively stagnant because they are set by the government through applicable regulations, leaving PLN Batam no flexibility to adjust prices independently, so cost control, particularly of variable costs, is the main available means to maintain profitability.

To identify the lowest-cost operating pattern, the variable cost and fuel cost per kWh of each plant type were calculated from the income statements and production volumes, as shown in Table 10.

Table 10. Variable Cost and Fuel Cost by Power Plant Type (Rp/kWh)

Plant Type	VC 2020	VC 2021	VC 2022	VC 2023	VC 2024	Fuel Cost 2024
PLTU	455	495	646	664	672	672
PLTG	171	897	1,079	941	1,190	1,190
PLTGU	1,264	654	738	719	915	672
PLTD	1,756	1,841	2,358	2,491	3,029	2,656
PLTMG	1,772	1,948	1,310	1,074	1,023	787
PLTS	–	–	–	404	571	–

Plant Type	VC 2020	VC 2021	VC 2022	VC 2023	VC 2024	Fuel Cost 2024
IPP	–	–	–	–	933	760

Source: Data processed from PT PLN Batam Financial Statements and PLN Statistics 2020–2024

Table 10 indicates that, in 2024, the plants with the lowest variable costs were PLTS (Rp571/kWh) and PLTU (Rp672/kWh), followed by PLTGU (Rp915/kWh) and IPP plants (Rp933/kWh), whereas PLTMG (Rp1,023/kWh), PLTG (Rp1,190/kWh), and PLTD (Rp3,029/kWh) were the most expensive. This order is consistent with the cost hierarchy reported by Arifin (2015), in which diesel and gas-fired peaking plants have the highest production costs and coal-fired plants are among the cheapest. The results therefore suggest that PLTGU should be prioritized over PLN-owned PLTMG within the controllable portion of the dispatch.

Load Characteristics of the Batam System in 2024

Table 11 summarizes the 2024 daily average load characteristics of the Batam system by plant, and Figure 2 shows the corresponding hourly load curve.

Table 11. Daily Average Load Characteristics of the Batam Electric Power System, 2024

Plant	Installed Capacity (kW)	Available Capacity (kW)	Availability Factor	Capacity Factor (%)	Annual Production (kWh)
PLN PLTMG	26,250	22,500	0.51	59.09	116,784,409
PLN PLTGU	135,290	125,540	0.72	77.12	850,382,206
PLN PLTD	59,130	40,170	0.003	0.50	1,766,729
PLN PLTS	1,000	1,000	0.14	14.40	1,264,973
IPP PLTGU	164,200	164,200	0.80	79.71	1,149,647,266
IPP PLTMG	314,720	312,765	0.48	48.24	1,325,311,435
IPP PLTG	70,000	70,000	0.46	45.42	279,281,725
IPP PLTD	25,000	25,000	0.02	1.70	3,733,303
IPP PLTU	130,000	94,175	0.62	85.01	703,213,313
Total	**925,590**	**855,350**	**0.52**	**58.98**	**4,431,385,359**

Source: Data processed from PLN Batam system operation data 2024

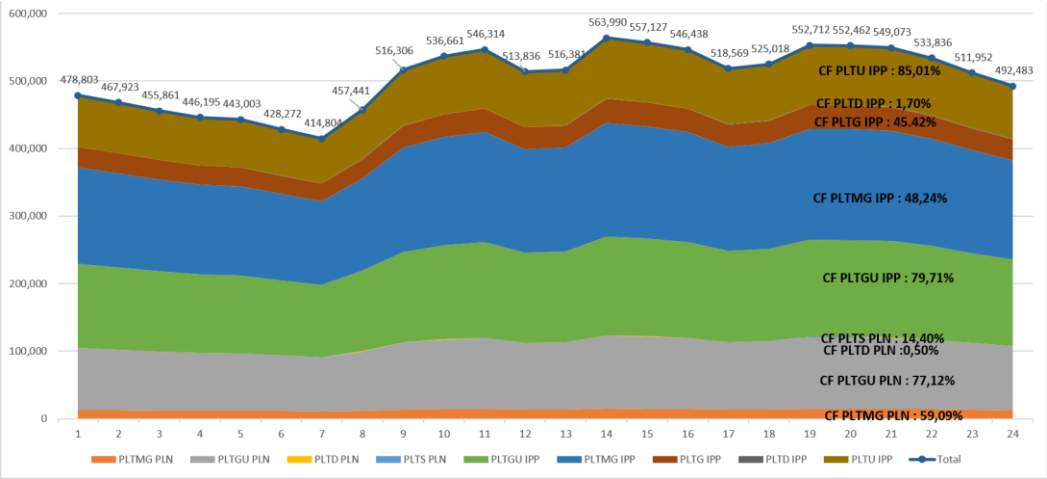


Figure 2. Daily Average Load Curve of the Batam System, 2024

Source: Data processed from PLN Batam system operation data 2024

The total installed capacity of the system is 925,590 kW, with an available capacity of 855,350 kW. Based on the daily load curve, the load reached its lowest point at 07:00 (414,193 kWh) and its highest point at 14:00 (563,160 kWh). The load pattern shows two peak periods: a daytime peak around 10:00–11:00 driven by industrial and commercial activity, and an afternoon-to-evening peak around 14:00–21:00 reflecting the accumulation of residential and business activity. Combined cycle plants (PLTGU) bore the largest share of the load with 2,000,029,472 kWh or 45.13% of total production, followed by gas engine plants (PLTMG) with 1,442,095,843 kWh (32.54%), coal-fired plants (PLTU) with 703,213,313 kWh (15.87%), and gas turbine plants (PLTG) with 279,281,725 kWh (6.30%), while diesel plants (PLTD) and solar plants (PLTS) contributed only 0.12% and 0.03%. The capacity factors reveal uneven operating patterns: PLTU recorded the highest CF at 85.01%, followed by the combined PLTGU fleet at 78.58% and PLTMG at 48.97%, whereas PLTD operated at only 0.96%, indicating its role as a reserve unit. Notably, the PLN-owned PLTMG operated at a CF of 59.09%, comparable to an intermediate-load plant even though its variable cost is higher than that of PLTGU.

Evaluation of the 2024 Income Statement with Reasonable Compensation

Because PLN Batam receives no subsidy or compensation, the 2024 income statement was first evaluated by calculating a reasonable compensation based on a 7% profit margin, as presented in Table 12.

Table 12. Calculation of Reasonable Compensation for the Batam System, 2024

Component	Unit	Value
Energy sold	kWh	3,588,240,000
Electricity sales	Rp	5,246,697,089,715
Operating expenses	Rp	5,370,816,789,019
Fixed cost	Rp (Rp/kWh)	1,186,161,506,658 (331)
Variable cost	Rp (Rp/kWh)	4,184,655,282,361 (1,166)
Gap between sales and operating expenses	Rp (Rp/kWh)	124,119,699,304 (35)
Average selling price	Rp/kWh	1,462.19
Operating expenses per unit	Rp/kWh	1,496.78
Profit margin	%	7
Compensation	Rp (Rp/kWh)	132,808,078,255 (37)
Adjusted sales rate	Rp/kWh	1,499.20
Contribution margin	Rp/kWh	332.99
Contribution margin ratio	%	22.21
BEP in units	kWh	3,562,148,029
BEP in rupiah	Rp	5,340,387,970,042
Operating profit after compensation	Rp	8,682,178,955

Source: Data processed from PT PLN Batam Financial Statements 2024

Table 12 shows that a reasonable compensation of Rp132.81 billion, calculated as the gap between operating expenses and electricity sales plus a 7% margin, raises operating revenue by 2.53% to Rp5,379.51 billion while operating expenses remain unchanged. The effective tariff becomes Rp1,499.20/kWh, the contribution margin increases to Rp332.99/kWh, and the BEP falls to 3,562.15 million kWh, slightly below actual sales. As a result, the

operating result of the Batam system turns from a loss of Rp124.12 billion into an operating profit of approximately Rp8.68 billion.

Merit-Order Optimization of Power Plant Dispatch

Since fuel is the largest variable cost component and the IPP plants operate under fixed contractual arrangements, the optimization focused on PLN-owned plants: the capacity factor of PLTGU, which has a lower variable cost, was increased, and the capacity factor of PLTMG was decreased, while the CF of all IPP plants was kept unchanged, using the 2024 daily average load characteristics. The results are compared with the existing condition in Table 13.

Table 13. Comparison of Optimization Results with the Existing 2024 Condition

Description	Existing 2024	Optimization 2024	Change (%)
Total energy production (kWh)	4,431,385,359	4,431,385,361	0.0
Capacity factor of PLN PLTMG (%)	59.1	14.6	-75.2
Capacity factor of PLN PLTGU (%)	77.1	85.1	10.3
Production of PLN PLTMG (kWh)	116,784,409	28,944,411	-75.2
Production of PLN PLTGU (kWh)	850,382,206	938,222,206	10.3
Fuel cost of PLN PLTMG (Rp)	91,965,791,229	22,793,245,138	-75.2
Fuel cost of PLN PLTGU (Rp)	571,328,309,386	630,343,512,533	10.3
Total fuel cost (Rp)	**3,299,183,651,367**	**3,289,026,308,423**	**-0.3**
O&M cost of PLN PLTMG (Rp)	66,729,863,756	16,538,651,191	-75.2
O&M cost of PLN PLTGU (Rp)	485,927,241,395	536,120,964,329	10.3
Total O&M cost (Rp)	**554,393,019,314**	**554,395,529,682**	**0.0005**

Note: PLTD, PLTS, and all IPP plants are unchanged.

Source: Data processed from PLN Batam system operation data 2024

Table 13 shows that the CF of PLTGU increased by 10.3% from 77.1% to 85.1%, while the CF of PLTMG decreased by 75.2% from 59.1% to 14.6%, with total production unchanged. The fuel and O&M costs of each plant moved in proportion to their production, so the total fuel cost decreased by only 0.3% and the total O&M cost remained practically constant. When these results were included in the income statement, operating expenses decreased by 0.19% to Rp5,360.66 billion and variable costs decreased by 0.24% to Rp4,174.50 billion. Table 14 compares the evaluation and optimization scenarios, both including the reasonable compensation.

Table 14. Comparison of the Evaluation and Optimization Scenarios, 2024

Description	Evaluation	Optimization	Change (%)
Fixed cost (Rp/kWh)	331	331	0.00
Variable cost (Rp/kWh)	1,166	1,163	-0.24
BPP (Rp/kWh)	1,497	1,494	-0.19
Average selling price (Rp/kWh)	1,462	1,462	0.00
Adjusted tariff with compensation (Rp/kWh)	1,499	1,499	0.00
Operating expenses (Rp billion)	5,370.82	5,360.66	-0.19
Contribution margin (Rp/kWh)	332.99	335.82	–
Contribution margin ratio (%)	22.21	22.40	–
Operating profit (Rp billion)	8.68	18.84	–
BEP in units (kWh)	3,562,148,029	3,532,129,045	–

Description	Evaluation	Optimization	Change (%)
BEP in rupiah (Rp billion)	5,340.39	5,295.38	–

Source: Data processed from PT PLN Batam Financial Statements and system operation data 2024

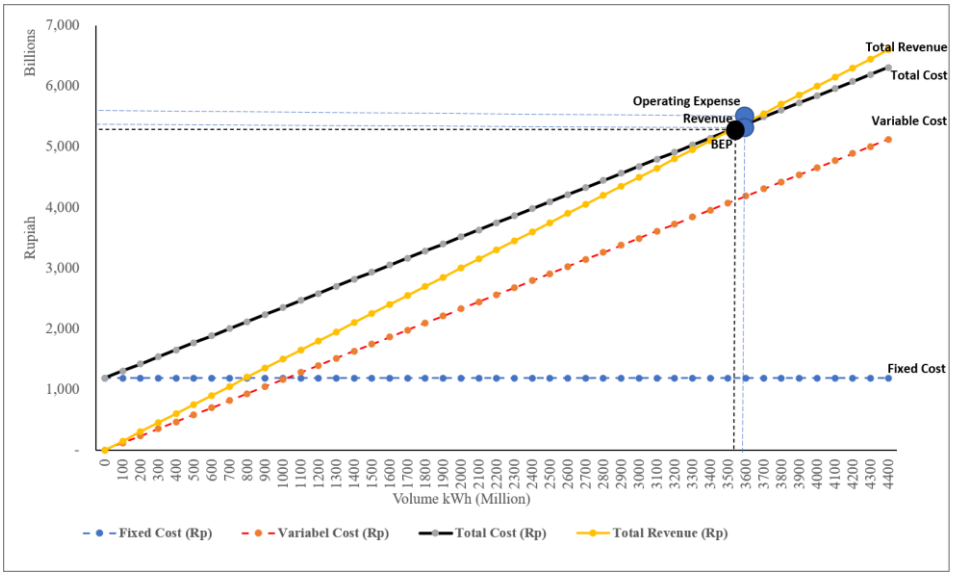


Figure 3. Cost Volume Profit Chart after Optimization, 2024
Source: Data processed from PT PLN Batam Financial Statements 2024

As shown in Table 14 and Figure 3, the combination of compensation and a 0.19% reduction in operating expenses lowers the BEP to 3,532.13 million kWh and Rp5,295.38 billion and increases the operating profit to approximately Rp18.84 billion. However, the BPP decreases only from Rp1,497/kWh to Rp1,494/kWh, which remains above the average selling price of Rp1,462/kWh. The limited effect is explained by the cost structure: PLN-owned plants supply only about one-fifth of total production, and the share that can be redispatched is small relative to the IPP and leased capacity operating under fixed arrangements. This finding supports the view of Nugroho et al. (2018) and Thommessen et al. (2025) that merit-order dispatch reduces operating cost, but it also shows that, in a gas-dominated isolated system, dispatch optimization cannot overcome a structural gap between cost and tariff. Consistent with Purvin et al. (2018) and Antweiler and Muesgens (2025), a lasting reduction requires access to cheaper energy through interconnection or storage-supported renewable generation.

Long-Term Strategy and Implementation Plan

Two investment alternatives were therefore considered: Development #1, the construction of PLTS with a BESS with 2028 capacities of 1,209 MWp and 6,000 MWh, respectively; and Development #2, the construction of a submarine cable transmission line with a 2028 capacity of 300 MW to transfer energy from Sumatra, whose 2024 BPP is Rp1,380/kWh. Both options require further in-depth study given the continuously rising demand and the power requirements of data centers. The implementation plan based on the 5W+1H framework is summarized in Table 15.

Table 15. Implementation Plan for Reducing the BPP of PT PLN Batam (5W+1H)

Aspect	Description
What	Short term: merit-order redispatch by increasing the CF of PLTGU and reducing the CF of PLTMG/PLTG, and requesting compensation or subsidies from the government. Long term: developing a 500 kV Sumatra–Batam subsea cable interconnection and/or PLTS integrated with BESS
Why	To end selling below cost (BPP Rp1,497/kWh versus selling price Rp1,462/kWh), rapidly reduce variable costs, and access the cheaper Sumatra system (Rp1,380/kWh) to sustain positive margins
Where	Load Dispatch Center of the Batam–Bintan system for operational optimization; the Sumatra–Batam cable route and potential PLTS sites in PT PLN Batam's service area for investment
Who	Operations Directorate (generation and transmission) for dispatch SOP and merit order; Business Development and Finance Directorates for capital budgeting (NPV), investment schemes, and compensation negotiation; PT PLN (Persero) Head Office and the Ministry of Energy and Mineral Resources for approving investment, the RUPTL, and compensation regulations
When	2024–2026: stabilization through redispatch and compensation proposals; 2026–2028: feasibility study, permitting, and procurement; 2028: commercial operation of the interconnection with an initial transfer of 300 MW
How	Update the load management matrix to prioritize PLTU and PLTGU for base load and assign PLTMG and PLTG as peaking units; prepare audited statements and submit a compensation claim at 7% above operating costs to the Ministry of Energy and Mineral Resources and the Ministry of Finance; establish a Project Management Office for the subsea cable project, covering financing schemes and construction monitoring

Source: Authors

The plan is justified by the CVP findings: even with merit-order optimization, the BPP can only be reduced to Rp1,494/kWh, which remains structurally higher than the selling price, so a short-term request for compensation is a legitimate measure for the company's survival. Compensation, however, is not a permanent solution. The capital expenditure for the Sumatra–Batam subsea cable is supported by the prospect of permanent efficiency from accessing supply with a production cost of Rp1,380/kWh, in line with the RUPTL PT PLN Batam 2025–2034 and the need to serve surging demand from industry and data centers.

CONCLUSION

This study concluded that the high electricity supply cost (Biaya Pokok Penyediaan, BPP) in the Batam power system was primarily driven by variable costs, which accounted for 77.91% of total operating expenses in 2024. These costs were dominated by fuel expenditures, particularly natural gas, which represented 85.22% of the fuel mix amid rising commercial gas prices. The situation was further exacerbated by relatively unchanged electricity tariffs and the absence of government subsidies or compensation. Consequently, the contribution margin per unit declined from IDR 485.45/kWh in 2020 to IDR 295.98/kWh in 2024, while the break-even sales volume exceeded actual electricity sales by 419.35 million kWh, resulting in an operating loss of IDR 124.12 billion. Merit-order-based generation dispatch optimization, involving an increase in the capacity factor of combined-cycle gas turbine power plants (Pembangkit Listrik Tenaga Gas dan Uap, PLTGU) from 77.1% to 85.1% and reduced reliance on higher-cost gas engine power plants (Pembangkit Listrik Tenaga Mesin Gas, PLTMG), was

projected to decrease the BPP from IDR 1,497/kWh to IDR 1,494/kWh. However, this remained above the average electricity selling price of IDR 1,462/kWh, indicating that operational efficiency improvements alone were insufficient to eliminate operating losses. Accordingly, PT PLN Batam should evaluate natural gas consumption efficiency and consider diversifying its generation portfolio toward lower-cost energy sources, including coal-fired generation where economically and environmentally feasible, and renewable energy technologies. Government subsidies or compensation mechanisms should also be considered, with compensation calculated using a 7% profit margin potentially restoring positive operating performance. Furthermore, long-term investments in solar photovoltaic power plants (Pembangkit Listrik Tenaga Surya, PLTS) integrated with battery energy storage systems (BESS), or the development of a 500-kV Sumatra–Batam submarine electricity transmission interconnection, should be evaluated to facilitate access to lower-cost electricity, particularly from the Sumatra power system, which recorded a BPP of IDR 1,380/kWh. Future research should conduct comprehensive capital budgeting analyses to compare the financial feasibility of these investment alternatives and incorporate uncertainties associated with fuel prices and foreign exchange rate fluctuations into the cost-volume-profit (CVP) model.

FUNDING

This study did not receive any specific funding from governmental institutions, private organizations, or other funding agencies.

CONFLICT OF INTEREST

The authors declare that there are no conflicts of interest related to the conduct of the research, preparation, or publication of this article.

AUTHOR CONTRIBUTIONS

All authors contributed to the preparation of this article. Marudut Jon Ferry Simarmata and Oktofa Yudha Sudrajad were responsible for the conceptualization of the study, data collection and analysis, interpretation of the results, and manuscript preparation, as well as the review, editing, and final approval of the manuscript.

GENERATIVE AI STATEMENT

The authors declare that no generative artificial intelligence was used in the preparation of this article.

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