Transforming Investment Structures in Capital-Intensive Electricity Utilities: A Managed Service Approach for CapEx-to-OpEx Transformation

[1]Ignatius Rendroyoko, [2]Najahul Imtihan, [3]Ishak Sinaga
[1] Institute Technology of PLN, Jl. Lingkar Luar Barat Duri Kosambi, Cengkareng Jakarta Barat, 11750.
[2] Universitas Gadjah Mada, Jl. Grafika No. 2, Sinduadi, Mlati, Kabupaten Sleman, Daerah Istimewa Yogyakarta 55281
[3] PT PLN (Persero), Jl. Trunojoyo Blok M-I No. 135, Jakarta 12160

Abstract - ***Electric utilities operate in a capital-intensive environment characterized by substantial infrastructure investment requirements, long asset life cycles, regulated tariffs, and relatively stable financial returns. Increasing electricity demand and energy transition initiatives have intensified the need for alternative financing mechanisms that support infrastructure expansion while maintaining service reliability and affordability. This study evaluates the transformation of conventional Capital Expenditure (CapEx)-based investment structures into Operating Expenditure (OpEx)-based arrangements through managed service models in electricity utilities. Using a mixed-method explanatory case study and techno-economic analysis, the study examines managed service implementation for 160 kVA distribution transformers in Indonesia's electricity distribution sector. The analysis incorporates lifecycle cost evaluation, cash flow assessment, and financial indicators including Net Present Value (NPV) and Internal Rate of Return (IRR). The results show that the managed service model improves financial flexibility by replacing large upfront investments with predictable periodic payments and transferring operational risks to service providers. However, this flexibility is accompanied by an approximately 15% increase in lifecycle NPV compared with the conventional Total Expenditure (TOTEX) model. These findings demonstrate that managed services represent a viable alternative financing strategy for capital-intensive electricity utilities facing investment constraints.***

Keywords — Electricity Utilities, CapEx-to-OpEx Transformation, Managed Service Model, Capital-Intensive Infrastructure, Utility Business Model Innovation.

I. Introduction

Electricity utilities have long been recognized as capital-intensive companies that rely heavily on substantial upfront investments to establish and sustain large-scale infrastructure systems across generation, transmission, and distribution networks [1]. The physical assets underpinning these systems typically exhibit long operational lifetimes and high capital irreversibility, which necessitate structured planning approaches to ensure cost recovery over extended time horizons [2]. In most national electricity sectors, tariff-setting mechanisms have been governed by a regulatory framework designed to balance efficiency, affordability, and financial viability, resulting in relatively stable but moderate returns for utility companies [3]. Within this conventional paradigm, investment strategies are predominantly structured around capital expenditure (CapEx), reflecting the need for utilities to maintain ownership and control over critical infrastructure assets [4], [5].

However, the global energy transition has introduced a new layer of complexity, as utilities are now required to accommodate rapid technological change, integrate distributed energy resources and renewable energy (RE), and modernize aging networks simultaneously [6]. These emerging requirements have significantly increased the scale and urgency of investment needs, while traditional financing mechanisms are becoming progressively constrained, particularly in emerging economies [7]. Consequently, electricity utilities are increasingly exploring alternative financial and operational arrangements that can reduce capital intensity without compromising service reliability [8]. One such approach involves the gradual transition from asset ownership models toward service-based configurations, where certain infrastructure components are delivered through managed service arrangements [9].

In this arrangement, the third-party provider assumes responsibility for financing, deploying, operating, and maintaining the infrastructure assets, while the utility company shifts to periodic payment obligations categorized as operating expenses (OpEx) [10]. This reconfiguration of investment structures enables utilities to transform large upfront capital commitments into more flexible and predictable operational cost streams, thereby improving short- to medium-term financial manageability [11]. At the same time, such transformations alter the traditional boundaries of utility business models by introducing hybrid structures that combine asset ownership with service procurement [12]. The electricity distribution sector represents a particularly relevant domain for this transition, as it requires continuous investment in network expansion, reliability enhancement, and digitalization under increasingly constrained financial conditions [13].

In Indonesia, this dynamic condition also occurs because electricity utility companies face rising demand and significant infrastructure development requirements, while facing limitations in accessing sufficient capital through conventional financing channels [5], [14]. This situation has led to the gradual adoption of managed service models in selected distribution activities, particularly in areas such as metering systems, grid automation, and supporting infrastructure services [15].

Electricity infrastructure development is capital-intensive because it requires substantial, sustained, and large-scale financial commitments to build and maintain an interconnected power grid that provides a reliable electricity supply across large geographic areas [16]. The investment structure of electric utilities typically comprises three core segments: generation, transmission, and distribution, each requiring substantial capital allocation due to the technological complexity and scale of the associated physical assets.

Power Generation assets, including thermal and RE plants, require substantial upfront investment due to engineering requirements, fuel systems, and environmental compliance obligations that shape their cost structures [17]. Transmission networks, which transport electricity over long distances, involve high-voltage infrastructure such as substations and transmission lines that are costly to construct and expand due to land use and system integration constraints [18]. Distribution systems, as a sector that directly interacts with customers, also require continuous investment in network strengthening, reliability enhancement, and customer connection infrastructure to meet evolving demand patterns [19].

These electricity system assets have long operational lifecycles, typically 20 to 30 years, necessitating the adoption of long-term financial planning frameworks and asset lifecycle management strategies [20]. High sunk costs are increasingly a hallmark of electric utilities, as infrastructure investments are largely irreversible and cannot be easily reused without significant economic losses after implementation [21]. As a result, electricity utilities are typically subject to regulatory oversight that governs pricing and investment decisions to balance efficiency, affordability, and long-term system reliability [19].

The CapEx-dominated investment model in electric utilities is increasingly showing structural weaknesses due to the large upfront capital requirements required to develop large-scale infrastructure systems [6]. These high initial investments clearly create financial constraints, especially when utilities have limited access to affordable financing. Furthermore, a heavy reliance on capital expenditures places ongoing pressure on companies' balance sheets, as large infrastructure projects are typically financed through debt accumulation and long-term capital allocations [22]. Such financial pressures can reduce utilities' ability to fund the additional investments needed for grid modernization and energy transition initiatives [23].

Another limitation is the long payback period of infrastructure investments, where cost recovery spans decades and is affected by changing economic and policy conditions. This increases the risk of stranded assets, as investments may lose value before their technical lifetime ends. Additionally, regulatory delays in tariffs or approvals can disrupt revenues and heighten financial uncertainty. CapEx-based models can create inefficiencies when regulatory incentives rather than operational needs drive investments, leading to poor resource allocation and slower adoption of efficient technologies [24]. Long-term capital commitments also reduce financial flexibility, limiting adaptation to changing markets [23]. Therefore, alternative approaches are needed; OpEx-based models, especially managed services, offer greater flexibility and a lower financial burden than traditional CapEx-dominated frameworks.

Electric utilities worldwide face mounting challenges from technological change, evolving regulations, and energy transition, requiring improved performance alongside cost efficiency. To remain sustainable, utilities are encouraged to adopt scenario planning that includes potential business model transformations [25]. One such approach is the managed services model, in which a third-party provides finances, deploys, and operates specific infrastructure assets [10]. Under this model, the provider retains ownership and operational control, while the utility pays recurring service fees as operational expenditure (OpEx).

Unlike conventional outsourcing, managed services involve deeper integration, long-term contractual commitments, and performance-based accountability [26]. This model transfers operational responsibility to the service provider while allowing utilities to focus on strategic and financial management. By shifting from a capital expenditure (CapEx) model to an OpEx-based approach, utilities can reduce capital intensity, improve liquidity, and enhance free cash flow. These financial gains can then be redirected toward strategic investments, particularly in energy transition initiatives and digitalization. Importantly, despite this arrangement, ownership of the asset typically reverts to the utility at the end of the contract period [27].

In the electricity sector, practical implementations of managed service models can be observed in applications such as Advanced Metering Infrastructure (AMI) as-a-service, where metering systems are deployed and managed by external vendors [24]. Similarly, grid automation services are increasingly delivered through managed service arrangements, enabling utilities to modernize network operations without incurring substantial upfront investment costs. A key component of managed service models lies in the structure of contractual agreements, which define roles, responsibilities, and performance expectations between utilities and service providers [28]. These contracts often incorporate performance-based payment mechanisms, where service fees are linked to predefined operational metrics such as reliability, efficiency, or service availability [23]. Another important aspect is risk transfer management, as managed service arrangements redistribute financial, operational, and technological risks from the utility to the service provider, thereby increasing the utility's financial flexibility [24]. This risk redistribution can enhance the utility's ability to manage uncertainties associated with technological change and evolving regulatory requirements [6].

Despite the increasing practical relevance of these developments, scholarly discussions on the transition from CapEx-dominated investment structures toward OpEx-based managed service models in electricity utilities remain relatively

underexplored. A preliminary review of the existing literature indicates that most previous studies have primarily focused on technical implementation, outsourcing practices, smart grid deployment, and utility financing [24], [26]. However, studies explicitly examining CapEx-to-OpEx transformation through managed service arrangements in electricity utilities remain limited, particularly in emerging economy contexts such as Indonesia. In addition, existing studies tend to discuss financial, operational, and technological dimensions separately, resulting in a fragmented understanding of investment structure transformation in electricity utilities [6], [23].
To address these gaps, this study is guided by the following research questions:
RQ1: How can managed service arrangements facilitate the transformation from CapEx-based investment structures to OpEx-based expenditure models in capital-intensive electricity utilities?
RQ2: What are the financial, operational, and strategic implications of adopting managed service models in the Indonesian electricity distribution sector?
The novelty of this study lies in reconceptualizing managed services not merely as an outsourcing mechanism, but as a strategic investment restructuring framework that enables CapEx-to-OpEx transformation in electricity utilities. Unlike previous studies that mainly discuss outsourcing efficiency, smart grid implementation, or infrastructure financing separately [24], [26], this study integrates perspectives on investment structure transformation, risk allocation, financial flexibility, and business model evolution within a unified analytical framework. Moreover, by focusing on the Indonesian electricity distribution sector, this study contributes empirical insights from an emerging economy context that remains underrepresented in the existing literature [5], [14].
Therefore, this study aims to examine how managed service approaches can facilitate CapEx-to-OpEx transformation in capital-intensive electricity utilities, with a specific focus on the evolving practices observed in the Indonesian electricity distribution sector.

II. Research Method

This study adopts a mixed-method approach within an explanatory case study design to provide a comprehensive understanding of the transformation of investment structures in electricity utilities from a Capital Expenditure (CapEx) model to an Operating Expenditure (OpEx)-based managed service model. The integration of qualitative and quantitative methods enables the study to capture both the contextual dynamics of organizational transformation and the financial implications associated with investment restructuring.
The qualitative component aims to explore the institutional, regulatory, and strategic factors influencing the implementation of managed service arrangements in electricity distribution systems. This approach facilitates a deeper understanding of organizational responses, implementation mechanisms, and stakeholder perspectives that cannot be fully represented through numerical data alone. Meanwhile, the quantitative component evaluates the financial consequences of shifting investment structures by comparing key economic indicators under CapEx-based and OpEx-based models, including cost structures, cash flow patterns, and investment performance metrics. The integration of both approaches enables the study to bridge conceptual understanding with empirical financial evaluation.
The explanatory case study approach was selected because the research problem involves complex interactions among technical infrastructure systems, financial mechanisms, and regulatory frameworks. This design allows the study to generate context-specific insights while maintaining analytical rigor, making it particularly suitable for investigating real-world transformation processes in capital-intensive electricity utilities.

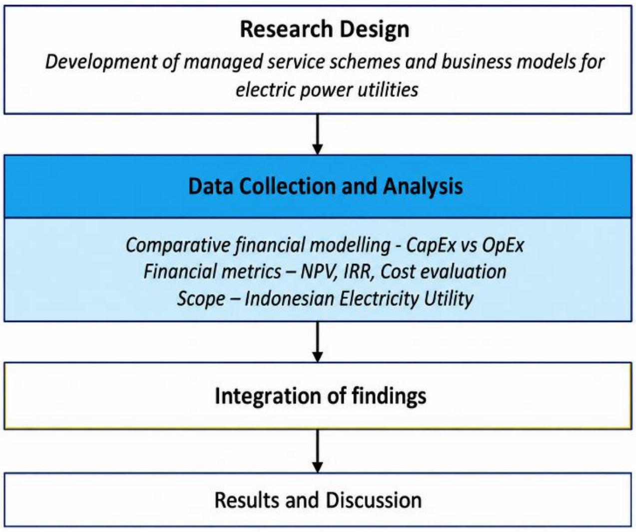

Figure 1. Research Methodology of Managed Service Approach for CapEx-to-OpEx Transformation

A. Research Design and Methodological Framework

As illustrated in Figure 1, the combined research methodology consists of six major stages. The process begins with identifying the core research problem, namely the growing mismatch between electricity infrastructure investment requirements and the limited availability of conventional financing mechanisms. This stage is followed by a comprehensive literature review covering traditional CapEx investment models, emerging financing challenges in utility sectors, and managed service arrangements as alternative financing mechanisms.
Subsequently, the study applies an explanatory mixed-method design combining qualitative investigation with quantitative financial analysis. Data collection was conducted through two complementary streams, namely qualitative information obtained from stakeholder interviews and document analysis, and quantitative information obtained from project-level financial and operational data.

The qualitative component involved semi-structured interviews with key stakeholders purposively selected based on their direct involvement in distribution asset planning, financial management, and managed service implementation. Informants consisted of managers and technical personnel from PLN distribution units and representatives from managed service providers. A total of six informants participated in this study. The interview protocol focused on four principal themes:
(1) Drivers of the CapEx-to-OpEx transformation; (2) Implementation mechanisms of managed service arrangements; (3) Perceived benefits and implementation challenges; (4) Financial and operational implications of the new investment model.
To improve methodological transparency and replicability, the profile of interview participants is presented in Table 1.

Table 1. Profile of Interview Informants

Informant Code	Position	Organization	Main Topics Discussed
I1	Distribution Planning Manager	PLN	Investment planning and asset expansion
I2	Finance Manager	PLN	CapEx and OpEx budgeting mechanisms
I3	Distribution Operation Manager	PLN	Operational implications of managed services
I4	Asset Management Officer	PLN	Asset lifecycle and risk allocation
I5	Business Development Manager	Service Provider	Managed service implementation strategy
I6	Technical Manager	Service Provider	Operation and maintenance responsibilities

The qualitative findings were analyzed using thematic analysis to identify recurring patterns, implementation challenges, and institutional drivers influencing the transition toward managed services. The quantitative analysis employed comparative financial modeling to evaluate the economic implications of CapEx and OpEx schemes.
The results obtained from both analytical streams were subsequently integrated through triangulation to ensure consistency, improve robustness, and enhance the validity of the research findings. The final stage synthesizes the results into managerial implications and policy recommendations for improving financial sustainability in electricity utilities.

B. Research Strategy: Embedded Case Study

This study employs an embedded case study strategy focusing on the implementation of managed services for distribution transformers within PLN's electricity distribution business. The embedded case study approach enables detailed analysis of a specific investment transformation while maintaining the broader organizational context in which the transformation occurs.
The case selection was based on purposive criteria to ensure analytical relevance and practical significance. PLN was selected because it is the sole electricity utility company in Indonesia and currently experiences substantial investment pressures associated with infrastructure expansion and energy transition programs. The Eastern Indonesia distribution system was chosen because it exhibits relatively high infrastructure growth requirements combined with financing constraints, thereby providing an appropriate setting for examining alternative investment mechanisms.
Furthermore, the 160 kVA distribution transformer was selected as the embedded unit of analysis because it represents one of the most commonly installed transformer capacities within PLN's distribution network and is extensively utilized for medium-scale customer load expansion and distribution system reinforcement. Consequently, this transformer capacity provides a representative basis for evaluating the financial implications of transitioning from traditional CapEx investment structures to managed service-based OpEx arrangements.
The context of this research is particularly relevant given PLN's current limitations in capital expenditure capacity, driven by increasing infrastructure demand and restrictions associated with conventional financing mechanisms. Consequently, managed service arrangements emerge as a practical alternative for reducing financial pressures while maintaining operational reliability and service quality. By focusing on PLN, the study also aims to generate insights transferable to other electricity utilities facing similar investment challenges.

C. Managed Service Framework

The managed service framework examined in this study represents a strategic partnership between an electricity utility company and a managed service provider that integrates investment, operation, and maintenance responsibilities throughout the lifecycle of distribution system assets, specifically distribution transformers.
Under this arrangement, service providers are responsible for procurement, installation, monitoring, preventive maintenance, and corrective maintenance activities based on performance-based contractual agreements. This model facilitates a transition from capital-intensive investment structures toward service-based payment mechanisms linked to key performance indicators such as equipment availability, reliability, and operational performance.

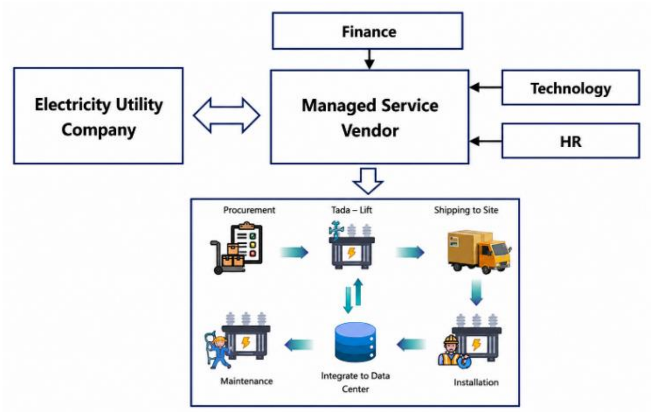

Figure 2. Conceptual Managed Service Framework between Electricity Utility and Service Provider

The framework also incorporates proportional risk allocation, incentive and penalty mechanisms, and digital monitoring technologies aimed at improving operational transparency and asset management efficiency. Overall, the managed service model contributes to improved total cost efficiency, optimized asset performance, and enhanced electricity service quality.

D. Financial Parameters and Economic Assumptions

The financial assumptions employed in this study were derived from official corporate and macroeconomic references to ensure analytical validity and transparency.

The Weighted Average Cost of Capital (WACC) of 7.36% was adopted based on PLN's corporate financing structure and prevailing financing costs. The inflation rate assumption of 2.92% was obtained from Indonesian macroeconomic indicators published by Bank Indonesia and the national statistical authority. Meanwhile, the economic life assumption of 10 years for the managed service arrangement was determined based on the typical contractual duration applied in infrastructure service agreements and was further validated through stakeholder interviews.

These assumptions were subsequently utilized as baseline parameters in the comparative financial evaluation of CapEx and OpEx schemes, including cost comparison, cash flow analysis, and investment feasibility assessment.

E. Comparative Financial Analysis

Based on the investment budget and operational expenditure data of PLN's distribution system, the study compares the economic performance of conventional direct funding schemes and managed service (OpEx) schemes for distribution transformers.

Figure 4. PLN Distribution System Investment Cash Budget 2021–2025

The investment budget data provide an overview of annual capital allocation requirements associated with distribution asset expansion and reinforcement under the conventional CapEx model.

Table 2. Operational Budget of Power Distribution System Utility

No	Description	Operational Budget 2026 (Rp.)	Cost realization as per March 2026 (Rp.)	%
1	Subtotal I	107,274,669,351.59	61,640,748,278.00	5.47
2	Subtotal II	1,853,576,610,514.07	437,462,016,791.00	94.53
	TOTAL	1,960,851,279,865.66	499,102,765,069.00	100.00

The operational budget analysis indicates that the majority of expenditure is allocated to maintenance activities and supporting operational services, while only a relatively small proportion is dedicated to direct asset replacement. This observation supports the feasibility of transitioning certain asset categories toward managed service arrangements.

Furthermore, the annual operating expenditure of the distribution system demonstrates a consistent increasing trend due to the continuous addition of distribution assets and network expansion activities.

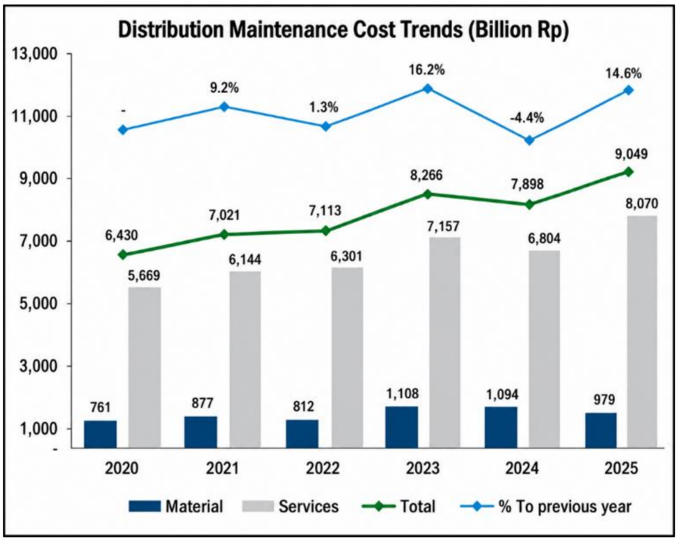

Figure 3. PLN Distribution System Operational Cost 2020–2025

This trend highlights the growing financial burden associated with maintaining conventional ownership-based investment structures and reinforces the need for alternative financing mechanisms such as managed services. The comparative analysis subsequently evaluates differences in investment requirements, annual operating costs, cash flow characteristics, financing structures, and overall financial performance indicators between CapEx and OpEx schemes. The results provide an analytical basis for assessing the feasibility and sustainability of managed service implementation as an alternative investment strategy for capital-intensive electricity utilities.

III. Results and Discussion

A. *Managed service-based OpEx in an Electricity Utility Company*

This chapter discusses a cost evaluation approach for implementing a managed service scheme for the operation and maintenance of distribution transformers, which are critical assets in the power distribution system. In the context of a utility company such as PLN, the transition from a CapEx-based model to an OpEx-based model requires a cost framework oriented towards the asset's lifecycle. This chapter outlines the calculation of managed service costs, including initial investment, annual O&M costs, and risk-related costs. It also compares Total Cost Equivalent Expenditure (TCEE) and Total Managed Service Expenditure (TMSE) to assess the economic efficiency, risk allocation, and financial implications of managed service implementation.

B. *Managed Service Expenditure*

As one of the proofs in this study, calculations are carried out on the specific case of PLN's efforts to develop a managed service (MS) business model for the operation and maintenance of distribution transformers (transformers). The calculated type and capacity of the distribution transformer is 160 kVA, a widely used capacity. Some of the data used in this simulation include investment costs, annual O&M costs, risk costs, the residual value of the asset, and several financial values , such as WACC, the discount rate, inflation, and assumptions regarding the economic life and usage life of distribution transformer assets. The purpose of this study is to analyze and calculate the Total Cost Equivalent Expenditure (TCEE) and Total Managed Service Expenditure (TCME) values in managing 160 kVA distribution transformers at PLN. The calculation formula for total expenditure can be seen in the equation (1). In addition, this study aims to determine the monthly managed service costs based on financial parameters such as WACC, discount rate, inflation, and the asset's economic life in a comprehensive measurable manner.

Referring to **Error! Reference source not found.**, which is the managed service management framework between the electric utility company and the service provider, this simulation will calculate the managed service fees the electric utility company can pay to the service provider. These managed service fees must be sufficient to enable the service provider to effectively perform operations and maintenance tasks, ensuring a reliable electricity supply to customers. On the other hand, these fees must be affordable for utility companies to maintain sustainability. Details of the distribution transformer total expenditure calculation are shown in **Error! Reference source not found.** below.

For editorial transparency and reproducibility, all financial tables in this study are presented as editable text tables rather than embedded images, allowing readers and reviewers to directly verify the underlying assumptions and calculations.

Table 1 Transformer asset cost data and assumptions

Item	Total (Rp.)
Cost of investment (Rp.)	60,537,380
Operational and Maintenance (O&M) costs per year (Rp.)	2,439,190
Cost of Risk	354,740
Salvage value	-

Table 3 shows a detailed breakdown of investment costs, O&M, risks, and the transformer's residual value, all of which contribute to the total expenditure. This total expenditure value is used to calculate Total Cost Equivalent Expenditure and total managed service expenditure, both calculated over a 10-year period. The managed service collaboration period was chosen because it represents the asset's most productive phase and is not at high risk of degradation, thus providing mutual benefits for both parties. Total expenditure is the total economic expenditure incurred by an organization during the life cycle of an asset or service, which includes capital expenditure (CAPEX) and operational expenditure (OPEX) in an integrated manner (see equation (1).

$$TotExp = CapEx_0 + PV(PM) + PV(Risk) + PV(Salvage) \quad (1)$$

where:

$CapEx_0$	capital expenditure (cost of investment)
$PV(PM)$	present value of O&M
$PV(Risk)$	present value of risk
$PV(Salvage)$	present value of salvage value

PV factor here is the present value, which is based on a time series, and is used for financial analysis, such as NPV, and the evaluation of equivalent annual costs

$$PV\ Factor = A = \sum_{t=1}^{10} \frac{(1+e)^{t-1}}{(1+r)^t} \quad (2)$$

where:

e escalation rate for annual O&M and risk costs (2.92%);

r discount rate or WACC (7.36%);

t time period (year)

The total expenditure evaluation in this study examines the financial implications of transitioning from a conventional CapEx business model to an OpEx-based managed service scheme, specifically for distribution transformers in electricity companies. This transition aligns with the adoption of service-based infrastructure management to increase financial flexibility and risk allocation. This analysis uses key financial parameters, including a Weighted Average Cost of Capital (WACC) of 7.36%, which also serves as the discount rate in the present value calculations, an inflation rate of 2.92%, and a 10-year economic life and asset utilization period. The WACC value was derived from PLN's corporate financing structure and prevailing financing costs, representing the company's average cost of obtaining capital from debt and equity sources. Given that the managed service scheme is evaluated from the perspective of PLN as the utility company, the use of PLN's WACC as the discount rate provides an appropriate benchmark for assessing investment feasibility and comparing alternative business models. Meanwhile, the inflation rate was adopted from Indonesia's macroeconomic indicators published by Bank Indonesia and the national statistical authority.

The annual Operation and Maintenance (O&M) costs and risk costs are adjusted using the PV factor to obtain their equivalent present values. These costs increase progressively over time, consistent with the applied escalation rate. In parallel, the residual value of the investment declines annually, reaching zero at the end of the asset's economic life, thereby reflecting full depreciation of the asset.

Table 4 Annual Cash Flow (Equivalent of TOTEX Δf and TOTEX Managed Service Δg)

Year	**Equivalent TOTEX Δf (IDR)**	**TOTEX Managed Service Δg (IDR)**
1	14,454,644	16,622,841
2	10,870,965	12,501,609
3	9,848,146	11,325,368
4	8,916,320	10,253,769
5	8,067,742	9,277,902
6	7,295,302	8,389,598
7	6,592,482	7,581,354
8	5,953,296	6,846,291
9	5,372,260	6,178,099
10	4,844,343	5,570,995

Referring to This analysis uses key financial parameters, including a Weighted Average Cost of Capital (WACC) of 7.36%, which also serves as the discount rate in the present value calculations, an inflation rate of 2.92%, and a 10-year economic life and asset utilization period. The WACC value was derived from PLN's corporate financing structure and prevailing financing costs, representing the company's average cost of obtaining capital from debt and equity sources. Given that the managed service scheme is evaluated from the perspective of PLN as the utility company, the use of PLN's WACC as the discount rate provides an appropriate benchmark for assessing investment feasibility and comparing alternative business models. Meanwhile, the inflation rate was adopted from Indonesia's macroeconomic indicators published by Bank Indonesia and the national statistical authority.

above, a comparison of Total Cost Equivalent Expenditure (TOTEX) and Total Managed Service Expenditure (MS) demonstrates a clear difference in lifecycle cost structures. The TOTEX calculation concentrates expenditures through an upfront capital investment followed by lower annual costs, while the managed service (MS) scheme redistributes financial obligations into periodic payments that include a return on capital.

Based on the discounted cash flow analysis, the resulting NPV for TOTEX is IDR 82.22 million, while the MS model reaches IDR 94.55 million, indicating a higher aggregate financial commitment. This additional difference reflects compensation for risk transfer and service provision. Furthermore, referring to the cash flow calculations in Table , the resulting internal rate of return (IRR), estimated at around 14–15%, exceeds the utility company's cost of capital (7.36%), indicating economic viability for the service provider. However, adoption from a utility perspective depends on increased operational efficiency, improved reliability, and risk-mitigation benefits, not solely on cost reductions.

The results indicate that the managed service model increases the lifecycle Net Present Value (NPV) by approximately 15% compared with the conventional TOTEX approach. Nevertheless, this increase should not be interpreted solely as an additional financial burden, since the additional expenditure effectively compensates for risk transfer, service continuity obligations, financing provision, and vendor responsibility throughout the asset lifecycle.

The findings obtained in this study are consistent with previous studies investigating service-based infrastructure financing models in electricity utilities and smart grid systems. Several studies on Advanced Metering Infrastructure (AMI)-as-a-Service and grid automation outsourcing models reported that service-based arrangements generally result in higher lifecycle Net Present Value (NPV) compared with direct ownership models due to the inclusion of financing costs, risk transfer premiums, and long-term service obligations. Nevertheless, these additional costs are frequently justified by improved cash flow flexibility, reduced capital constraints, and enhanced operational reliability.

Similarly, empirical evidence from international utility projects indicates that utilities increasingly adopt service-oriented asset management approaches not primarily to minimize total expenditure but to optimize risk allocation and preserve investment capacity for strategic infrastructure expansion. Therefore, the approximately 15% increase in NPV observed in the managed service scheme in this study should be interpreted as the economic cost of transferring technical, operational, and financing risks from the utility company to the service provider rather than as a reduction in financial efficiency.

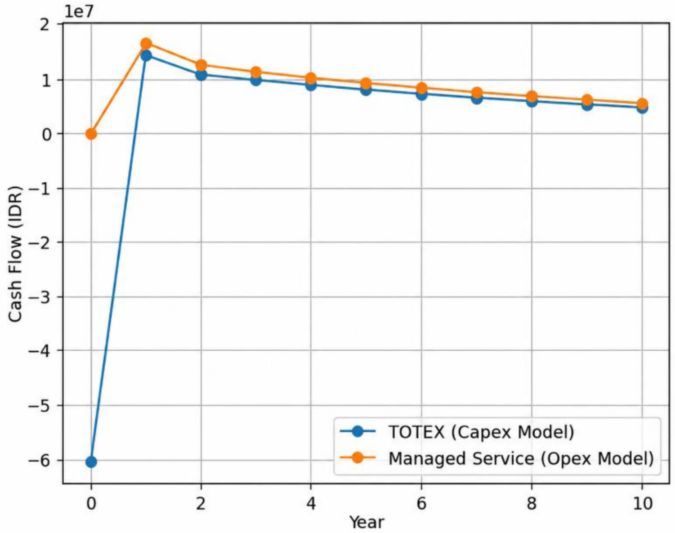

Figure 5 Cash Flow Comparison: TOTEX Vs Managed Service (160 KVA Transformer)

The calculation tables above show that the transition from a capital expenditure (CapEx) model to an OpEx-based managed service (MS) scheme fundamentally changes cost allocation and risk distribution. The MS approach increases cash flow predictability by converting a large initial investment into structured periodic payments, thereby increasing certainty in financial planning and budgeting. Simultaneously, a significant portion of the technical and operational risks is transferred to the service provider (vendor), reducing the burden on the utility company. However, this transformation is accompanied by higher total lifecycle costs, reflected in an approximately 15% increase in the net present value (NPV). This cost premium can compensate for the vendor's risk absorption, service continuity, and capital provision.

A comparison of cash flows between the TOTEX and MS schemes reveals two very different financial trajectories in asset management (see Figure). The TOTEX approach is characterized by a large initial cash flow due to capital investment, followed by relatively moderate annual expenses that decline over the asset's operational life. In contrast, the MS model replaces the initial capital charge with evenly distributed periodic payments, resulting in a smoother and more predictable cash flow profile. This reduces short-term financial stress and increases budgetary stability, while also generating service costs that accumulate overtime. Consequently, while MS reduces investment risk and operational uncertainty, it leads to higher cumulative expenses over the asset's life cycle. This graphical trend underscores the trade-off between financial flexibility and long-term cost efficiency.

C. Research Limitations

This study has several limitations that should be acknowledged. First, the financial simulation was conducted using a single embedded case involving a 160 kVA distribution transformer operating within PLN's Eastern Indonesia distribution system; therefore, the findings may not be directly generalizable to other transformer capacities, network characteristics, or utility environments. Second, the economic evaluation relies on several financial assumptions, including WACC, inflation, and asset lifetime, which may vary over time and across jurisdictions. Third, the managed service model was evaluated primarily from a financial and risk allocation perspective without incorporating detailed reliability indices such as SAIDI, SAIFI, or asset health indicators. Consequently, the operational benefits of managed services may not yet be fully captured in the present analysis.

D. Future Research

Future studies are encouraged to extend the analysis by considering multiple transformer capacities, alternative managed service contract structures, and sensitivity analyses under varying macroeconomic conditions. Furthermore, integrating technical reliability indicators and service quality metrics into lifecycle financial models would provide a more comprehensive assessment of managed service implementation in electricity utilities.

IV. Conclusion

Based on the results of the techno-economic analysis and business model evaluation conducted in this study, the following conclusions can be drawn:

1. The selection between the Total Expenditure (TOTEX) and Managed Service (MS) business models involves a fundamental trade-off between cost

efficiency and financial flexibility. The MS model transforms capital and operating expenditures into predictable periodic payments, thereby improving cash flow stability and transferring a significant portion of operational and business risks to the service provider.

2. The TOTEX model requires a substantial upfront capital investment, which may reduce short-term liquidity and increase the utility's exposure to technical, operational, and financial risks. However, this model offers lower overall life-cycle costs compared to the MS approach.
3. Financial analysis indicates that the cumulative cost of the MS model is higher, resulting in an increase in Net Present Value (NPV) of approximately 15% compared to the TOTEX model. Nevertheless, the estimated Internal Rate of Return (IRR), which exceeds the cost of capital, demonstrates that the MS scheme remains financially attractive for service providers and may encourage broader participation from private companies in electricity supply projects.
4. Therefore, the decision to adopt a Managed Service framework should not be based solely on cost considerations. Strategic factors such as risk allocation, operational reliability, financial planning objectives, and long-term sustainability should also be taken into account when determining the most appropriate business model for utility infrastructure development.

V. References

[1] J. A. Leiva Vilaplana, G. Yang, and E. Ackom, “From investment to net benefits: A review of guidelines and methodologies for cost–benefit analysis in the electricity sector,” *Energy Res. Soc. Sci.*, vol. 124, 2025, doi: 10.1016/j.erss.2025.104052.

[2] D. M. Newbery and M. G. Pollitt, “Market Design for a High-Renewables European Electricity System,” *Renewable and Sustainable Energy Reviews*, vol. 91, pp. 695–707, 2018.

[3] F. Bovera, M. Delfanti, E. M. Fumagalli, L. Lo Schiavo, and R. Vailati, “Regulating electricity distribution networks under technological and demand uncertainty,” *Energy Policy*, vol. 149, 2021.

[4] F. Roques and D. Finon, “Adapting electricity markets to decarbonization and decentralization,” *Energy Policy*, vol. 105, pp. 147–156, 2017.

[5] K. F. Afgani, “Transformasi Pengelolaan Aset dari Capex menjadi Opex pada Infrastruktur Distribusi PT PLN (Persero),” PT LAPI ITB, Bandung, Indonesia, 2025.

[6] I. E. A. (IEA), “World Energy Investment 2023,” IEA, Paris, France, 2023.

[7] D. Zhang, B. Wang, and P. Liu, “Financing renewable energy infrastructure: Challenges and opportunities,” *Renew. Energy*, vol. 172, pp. 1170–1183, 2021.

[8] S. Burger and M. Luke, “Business Models for Distributed Energy Resources: A Review and Empirical Analysis,” *Energy Policy*, vol. 109, pp. 230–248, 2017.

[9] P. R. Hartley, K. B. Medlock III, and O. Jankovska, “Electricity Reform and Retail Pricing in Texas,” *Energy Econ.*, vol. 80, pp. 1–15, 2019.

[10] F. P. Sioshansi, “Future utility business models: Utility customers and third-party providers,” *Energy Policy*, vol. 119, pp. 1–4, 2018.

[11] J. A. Leiva Vilaplana, G. Yang, and E. Ackom, “From investment to net benefits: A review of guidelines and methodologies for cost–benefit analysis in the electricity sector,” *Energy Res. Soc. Sci.*, vol. 124, 2025, doi: 10.1016/j.erss.2025.104052.

[12] F. Bovera, M. Delfanti, E. M. Fumagalli, L. Lo Schiavo, and R. Vailati, “Regulating electricity distribution networks under technological and demand uncertainty,” *Energy Policy*, vol. 149, 2021.

[13] A. C. Martins, M. D. Pereira, and R. Pasqualino, “Renewable Electricity Transition: A Case for Evaluating Infrastructure Investments through Real Options Analysis in Brazil,” *Sustainability*, vol. 15, no. 8, 2023.

[14] A. D. B. (ADB), “Indonesia Energy Sector Assessment, Strategy, and Road Map,” ADB, Manila, Philippines, 2020.

[15] P. T. P. L. N. (Persero), “Annual Report 2025,” PT PLN (Persero), Jakarta, Indonesia, 2025.

[16] K. L. Anaya and M. G. Pollitt, “Integrating distributed energy resources into electricity networks,” *Energy Policy*, vol. 145, 2020.

[17] J. Seppälä and P. Järventausta, “Analyzing Supply Reliability Incentive in Pricing Regulation of Electricity Distribution Operators,” *Energies (Basel).*, vol. 17, no. 3, 2024.

[18] T. Stannard and P. Barry, “Scale efficiency gains in utilities? The case of electricity distribution in New Zealand,” *New Zealand Economic Papers*, vol. 58, no. 3, pp. 299–308, 2024.

[19] J. Seppälä and P. Järventausta, “Analyzing Supply Reliability Incentive in Pricing Regulation of Electricity Distribution Operators,” *Energies (Basel).*, vol. 17, no. 3, 2024.

[20] H. Ahmadi, Y. Sunitiyoso, and A. Wicaksono, “Scenario Planning of PLN Indonesia Power in 2030: To Be a Leading Green and Sustainable Power Generation Company,” *European Journal of Business and Management Research*, vol. 8, no. 4, pp. 129–139, 2023.

[21] M. Kesuma, M. Henrika, and L. Ariswati, “The Impact of Capital Intensity on Financial Stability of Energy Sector Companies in Indonesia,” *Journal of Financial*

Economics & Investment, vol. 5, no. 2, pp. 115–127, 2025.
[22] F. Polzin, F. Egli, B. Steffen, and T. S. Schmidt, "How do policies mobilize private finance for renewable energy? A systematic review with an investor perspective," *Appl. Energy*, vol. 236, pp. 1249–1268, 2019.
[23] F. Polzin, F. Egli, B. Steffen, and T. S. Schmidt, "How do policies mobilize private finance for renewable energy? A systematic review with an investor perspective," *Appl. Energy*, vol. 236, pp. 1249–1268, 2019.
[24] K. L. Anaya and M. G. Pollitt, "Integrating distributed energy resources into electricity networks," *Energy Policy*, vol. 145, 2020.
[25] N. Imtihan and I. Rendroyoko, "Development of Alternative Energy Transition Scenarios for Electricity Utility Companies in 2045 using the Scenario Planning Method," *International Journal of Industrial Engineering and Engineering Management (IJIEEM)*, 2025.
[26] P. Burger, J. Tyson, I. Karpowicz, and M. Delgado Coelho, "Infrastructure Investment Challenges and Policy Responses," *Journal of Infrastructure Development*, vol. 11, no. 1–2, pp. 1–19, 2019.
[27] P. Hartley, K. B. Medlock III, and A. M. Jaffe, "The Changing Role of Utilities in Modern Electricity Markets," *The Energy Journal*, vol. 40, no. SI1, 2019.
[28] N. Stern and A. Sen, "Regulatory Frameworks and Infrastructure Investment," *Oxf. Rev. Econ. Policy*, vol. 36, no. 2, pp. 324–345, 2020.

.