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COST–BENEFIT ASSESSMENT OF ELECTROCHEMICAL BATTERY TECHNOLOGIES: THE CASE OF STAND-ALONE STORAGE

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Abstract:
In this study, a comparative cost–benefit analysis was conducted for four electrochemical battery technologies: lithium iron phosphate (LFP), flow batteries, sodium-sulfur (NaS) batteries, and nickel–manganese–cobalt oxide (NMC) batteries. Furthermore, an investment projection was examined within the scope of standalone storage applications. Based on the comparative analyses of electrochemical batteries, and taking into account technological advancements, market conditions, grid-scale applicability, investment costs, efficiency in terms of application areas, impacts on the energy market, and the standalone consumer profile, lithium iron phosphate (LFP), flow batteries, sodium-sulfur (NaS) batteries, and nickel–manganese–cobalt oxide (NMC) batteries have emerged as advantageous storage technologies at the point of maximum benefit in cost–benefit analysis studies. Positioned against prior research and relevant standards, this study is expected to advance the literature. In conclusion, it offers an investment-oriented cost–benefit assessment of the most widely deployed electrochemical energy-storage technologies, conducted within the context of a standalone storage consumer profile.

Keywords:
Cost Analysis, Electrochemical Batteries, Energy Storage Services, Stand-Alone Storage Profile, Electricity Consumption

1. Introduction
Within the framework of the Paris Agreement, it is aimed to strengthen global economic activities in combating climate change by developing new projects and increasing investments in this area. The environmental and economic challenges arising from the continued use of fossil fuels have accelerated the global demand for alternative energy sources. The emergence of these alternatives has positioned the concepts of green economy and green energy as critical pillars in the fight against climate change. In contrast to fossil fuels, most alternative energy sources today are renewable, offering sustainable solutions that prioritize environmental protection and resource preservation. These renewable energy sources not only focus on electricity generation but also align with the principles of the green economy—an economic model centered on environmental sustainability—by preventing the depletion of natural resources and addressing global challenges.

Currently, the most widely utilized renewable energy sources include wind, solar, hydropower, geothermal, and bioenergy. By 2024, the share of renewable energy in global electricity generation exceeded 30%. In Türkiye, low-carbon sources (hydro, wind, solar, and others) accounted for 45% of total electricity generation in 2024, surpassing the global average. During the first half of 2024, renewables contributed 53% of the country's electricity production. In terms of installed capacity, the share of renewables reached 57%, representing a significant portion of Türkiye's total power generation capacity. As the global share of renewables in electricity generation continues to grow, driven by their economic advantages, investments in these technologies have been increasing steadily. Correspondingly, renewable energy's influence on the global electricity sector is evident not only in production but also in new installations, with a remarkable share of 92.5%. Social equity, environmental preservation, and economic growth have emerged as the primary motivators for this global transition towards renewables. The strong link between fossil fuel consumption and climate change continues to drive both nations and individuals to reduce their carbon footprints. Declining costs of renewable energy technologies and the depletion of conventional energy resources further intensify interest in this sector. Moreover, renewable energy projects contribute to both social welfare and economic development in line with the Sustainable Development Goals.

Ensuring the continuity of renewable energy supply requires effective energy storage systems that can guarantee reliable electricity access in the event of disruptions and maintain a stable balance between supply and demand. Through the deployment of energy storage systems, more efficient and effective energy management strategies can be implemented. Beyond strategic management, storage technologies also facilitate reduced dependence on fossil fuels when harnessing intermittent sources such as wind and solar energy, thereby lowering the carbon footprint.

The rapid growth in renewable energy deployment has spurred the advancement of energy storage systems worldwide, accompanied by increased investment and research and development activities. Enhancing the efficiency of renewable energy utilization and minimizing energy losses have driven up demand for electrochemical energy storage technologies. Such technologies include lithium-ion batteries, sodium-based batteries, flow batteries, lead–acid batteries, and emerging aluminum-ion and magnesium-ion batteries. Furthermore, nickel-based batteries, widely used in the electric vehicle industry, have recently found applications in renewable energy storage, accelerating their technological development.

This study evaluates investment projections for selected battery technologies—lithium iron phosphate (a lithium-ion type), vanadium redox flow batteries, sodium–sulfur batteries, and nickel–manganese–cobalt oxide batteries—within the framework of cost–benefit analysis based on specific technical characteristics and ancillary services. In particular, cost–benefit assessments have been conducted for standalone residential storage applications and renewable energy integration scenarios. Additionally, cost–benefit analyses have been performed across various service domains for each battery technology examined. It is important to note that the analysis does not address the payback periods of energy storage investments. Instead, it focuses on evaluating the economic feasibility of levelized service costs in relation to projected electricity sale prices for each specific year.

2. Technical Specifications Used in the Cost–Benefit Analysis for Batteries

2.1. Technical Specifications

In the technical assessment, the parameters considered included rotational speed, storage capacity (hours), AC-to-AC cycle loss, efficiency, and response time. The measured or referenced values for these parameters, corresponding to each battery technology examined in the study, are summarized in Table 1.

Table 1. Technical Parameters Considered in the Cost–Benefit Evaluation

Battery Technology	Number of Cycles	Capacity (hours)	Round-Trip Loss (AC to AC)	Efficiency	Response Time
Lithium Iron Phosphate	5.000	4	%12	%92	Milliseconds (ms)
Nickel Manganese Cobalt	2.000	4	%14	%90–95	Milliseconds (ms)
Vanadium Redox Flow Battery	15.000	20	%32	%75–85	"Milliseconds (when pumps are operational), otherwise ~10 seconds."
Sodium–Sulfur	4.500	6	%22	%75–80	Milliseconds (ms)

This section presents a comparative overview of the key technical parameters of four distinct electrochemical energy storage technologies. Lithium Iron Phosphate (LFP) and Nickel Manganese Cobalt (NMC) batteries, with their high efficiency rates (exceeding 90%) and millisecond-level response times, offer significant advantages for short-duration, high-power applications. Vanadium Redox Flow Batteries stand out for their high cycle life (15,000 cycles) and extended energy storage capacity (20 hours); however, their relatively high cycle loss may pose a limitation in terms of efficiency. Sodium–Sulfur batteries, on the other hand, combine medium-to-high efficiency with long-duration capacity, making them particularly suitable for grid-scale load balancing applications. These parameters reveal the unique strengths and limitations of each technology, enabling suitability assessments for cost–benefit analyses across different application scenarios.

3. Analysis of Battery Investment Costs

The investment costs of batteries typically comprise the expenses associated with power support equipment, which determine the maximum power capacity of the grid connection (MW), and the costs of the storage systems, which define the storage capacity (MWh). From an investment perspective, the cost of an installed energy storage system is generally evaluated on a per-megawatt (MW) or per-megawatt-hour (MWh) basis. In this study, cost–benefit analyses were conducted under the assumption of a 4-hour charge/discharge cycle, with both capital expenditures (CAPEX) and operational expenditures (OPEX) expressed in USD/MWh for calculation purposes.

Table 2. Capital and Operating Costs Used in the Cost–Benefit Analysis

Battery Technology	Capital Expenditure (CAPEX)	Operational Expenditure (OPEX)
Lithium Iron Phosphate (LFP)	1-hour duration: USD 285,000 per MWh 4-hour duration: USD 228,000 per MWh	CAPEX * %2,5
Nickel Manganese Cobalt (NMC)	1-hour duration: USD 356,000 per MWh 4-hour duration: USD 284,000 per MWh	CAPEX * %2,5
Vanadium Redox Flow Battery (VRFB)	1-hour duration: USD 532,000 per MWh 4-hour duration: USD 330,000 per MWh 6-hour duration: USD 293,000 per MWh	CAPEX * %2,0
Sodium–Sulfur (NaS)	400.000 ABD$/MWh	CAPEX * %2,0

Table 2 presents a comparative assessment of the capital expenditure (CAPEX) per unit of energy and the annual operational expenditure (OPEX) for four electrochemical battery technologies. Lithium Iron Phosphate (LFP) and Nickel Manganese Cobalt (NMC) batteries exhibit relatively lower CAPEX values for a one-hour storage duration, with unit costs decreasing as the storage duration increases. Although Vanadium Redox Flow Batteries have a higher initial investment cost, they can offer a cost advantage as storage duration extends. Sodium–Sulfur batteries, listed with a single fixed cost value, emerge as a competitive option, particularly for long-duration storage requirements. The variation in operating cost ratios, ranging from 2.0% to 2.5% across technologies, indicates that the total cost of ownership in these systems is predominantly determined by the initial capital investment. For the cost–benefit analysis, economies of scale were taken into account: the unit cost of behind-the-meter storage systems was assumed to be 50% higher for residential applications and 10% higher for industrial applications compared to grid-scale storage facilities.

Based on the cost–benefit analysis, the projected investment costs for the electrochemical batteries examined in this study are illustrated in the figures below.

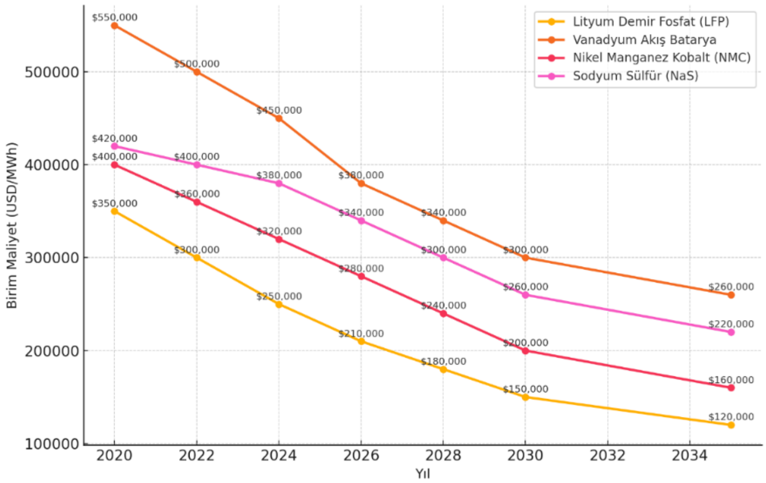

Figure 1. Unit Investment Cost Projections for Four Different Battery Technologies (2020–2035)

The comparative trends in the unit capital costs of four different electrochemical energy storage technologies over time are presented. Lithium Iron Phosphate (LFP) and Nickel Manganese Cobalt (NMC) batteries start at relatively lower cost levels and are projected to decline to USD 120,000/MWh and USD 160,000/MWh, respectively, by 2035. Vanadium Redox Flow Batteries, despite their high initial costs, demonstrate a notable long-term downward trend, reaching USD 260,000/MWh in 2035. Sodium–Sulfur (NaS) batteries, with moderate initial costs, are expected to fall to USD 220,000/MWh by 2035, positioning them as a cost-competitive option for long-duration storage applications. These trends indicate that, driven by technological advancements and economies of scale, battery costs are anticipated to decrease significantly over the next decade.

3.1. Levelized Cost of Service (LCOS)

Within the scope of the analysis, the Levelized Cost of Service (LCOS) calculations are based on:

$$LCOS = \frac{Yatırım\ Maliyeti * Yatırım\ Geri\ Dönüş\ Katsayısı + İşletme\ Maliyeti}{Deşarj\ Edilen\ Enerji\ Miktarı\ (MWh)}$$

$$Yatırım\ Geri\ Dönüş\ Katsayısı = \frac{i * (1+i)^n}{(1+i)^n - 1} \quad (1)$$

The analysis employed the following formula. For the computation of the Investment Recovery Factor (IRF), the discount rate (i) was set at 7%. In this formulation, n denotes the number of years representing the assumed total operational lifetime of the investment.

For storage applications, the Levelized Cost of Service (LCOS) is defined as the ratio of the discounted total costs to the discounted total discharged energy:

$$LCOS = \Sigma\ (C^t / (1+r)^t) / \Sigma\ (E\_out,^t / (1+r)^t) \quad (2)$$

On an annual basis, unit: USD/MWh:

$$LCOS \approx (CAPEX \cdot CRF)/(E\_out,y) + FOM/(E\_out,y) + VOM + p\_ch/\eta + C\_parasitic \quad (3)$$

- CAPEX: Capital investment (USD/kW and/or USD/kWh)
- CRF: Capital Recovery Factor (defined by r and n)
- FOM: Fixed operation and maintenance cost (USD/year)
- VOM: Variable operation and maintenance cost (USD/MWh)
- p_ch: Average cost of charging electricity (USD/MWh)

• η: Round-trip efficiency
• C_parasitic: Continuous consumption costs for auxiliary systems (e.g., pumps, heating)
• E_out,y: Annual energy delivered to the grid (= kWh_nominal · DoD · η · cycles/year · availability)

The cost–benefit analysis of the four electrochemical battery technologies reveals the advantages of energy storage through the Levelized Cost of Service (LCOS) metric. In addition to their primary role, these batteries are evaluated for their potential to deliver ancillary services such as arbitrage, capacity firming, frequency regulation, and voltage control. The inclusion of these ancillary services in the cost–benefit framework allows for a more comprehensive decision-making process and facilitates the economic scaling of battery investments.
Decision Rule in the Cost–Benefit Analysis:

$$\text{Net Benefit} \geq 0 \Leftrightarrow \text{Average Revenue per MWh (LRV)} \geq \text{LCOS} \quad (4)$$

The economic benefit of storage, represented by the Levelized Revenue Value (LRV), originates from the so-called "value stack" and can be classified as follows:
• Arbitrage revenue (price differential between high and low periods × discharged MWh)
• Reserve/capacity payments (capacity, spinning/non-spinning reserves, aFRR/mFRR)
• Frequency/voltage services (fast-response premiums)
Therefore, a technology with a low LCOS will only be economically viable if the LRV of the services it can provide is sufficiently high.
The technology-specific effects listed below influence the LCOS components and, consequently, determine the outcome of the cost–benefit analysis. For the cost–benefit evaluation, a detailed examination—based on technical parameters and ancillary services—expressed on an annual basis in USD/MWh, is presented for the batteries in Table 3.

Table 3. LCOS Impacts (LFP, NMC, VRFB, NaS)

Dimension / Batteries	LFP (Lithium Iron Phosphate)	NMC (Nickel Manganese Cobalt)	VRFB (Vanadium Redox Flow Battery)	NaS (Sodium–Sulfur)
η (Efficiency)	High (90–95%) → lower p_ch/η	High (90–95%)	Medium (75–85%) → higher *p_ch/η*	Medium (75–85%)
Cycle life & augmentation	4,000–10,000 cycles; potential need for augmentation → increase in FOM	2,000–7,000 cycles; augmentation more pronounced → FOM↑	10,000–20,000 cycles; no augmentation required, *E_out,y*↑	4,000–7,000 cycles; high-temperature operation
Fixed auxiliary consumption	Low	Low	Pumps → *C_parasitic*↑	Heating → *C_parasitic*↑
Duration / scalability	1–4 hours typical; CAPEX/kWh advantage decreases for longer durations	1–4 hours typical	Energy-independent scaling → for 4–20+ hours, (CAPEX·CRF)/E_out,y ↓	4–8 hours typical; competitive for longer durations
Response time	Millisecond level → higher fast-response service revenues (LRV↑)	Millisecond → LRV↑	Pumps operating → fast; otherwise slow → limited fast-service LRV	Millisecond level

Applicable services	Arbitrage + frequency/aFRR, behind-the-meter peak shaving	Arbitrage + fast ancillary services	Long-duration energy shifting, islanding/grid support	LDES, load balancing, islanding mode

For short-duration, high-value fast-response services (e.g., frequency regulation, peak shaving), the high efficiency (η) and millisecond-level response time of LFP and NMC technologies make their LCOS highly competitive. In such cases, the LRV is typically high, increasing the likelihood that LRV $\geq$ LCOS is satisfied. For medium-to-long-duration energy shifting (4–12+ hours), VRFB and NaS technologies, despite having lower efficiency, benefit from exceptionally high cycle life and energy-side scalability, which reduces the $(CAPEX \cdot CRF)/E_{out,y}$ term; this enables them to maintain competitive LCOS in scenarios requiring extended storage durations. In sites with high ancillary service requirements (e.g., extreme climate conditions, low utilization rates), the $C_{parasitic}$ factor in VRFB and NaS increases LCOS, making higher utilization rates (cycles/year) a critical determinant of economic viability. In systems with high charging electricity prices, lower efficiency (VRFB/NaS) increases the p_{ch}/η component, and if the electricity price spread is not sufficiently wide, the risk of LRV < LCOS becomes more significant.

4. Standalone Storage in the Consumer Profile: 10 Mw/40 Mwh Installed Capacity

In this case study, a standalone Battery Energy Storage System (BESS) with a total installed capacity of 10 MW and a charge/discharge duration of 4 hours was evaluated. The modeling is based on the minimum installed capacity requirement of 10 MW for participation in the Balancing Power Market (DGP) and Ancillary Services Market (YH). The comparison scope includes lithium-ion-based LFP and NMC chemistries, as well as flow battery and NaS technologies. For flow batteries, where investment costs are predominantly concentrated in power equipment, it is possible to increase energy capacity at a relatively limited additional cost while keeping the installed power constant. Therefore, a 6-hour configuration was also examined for the flow battery technology.

Within the analytical framework, the unit cycle cost for each technology was first derived from its investment cost and economic lifetime. To this, the energy losses arising from charge–discharge inefficiency, the cost of charging electricity, and variable grid tariffs were added. Under hourly market price projections, an operational trigger rule was applied in which the facility is dispatched in any given hour when the marginal arbitrage revenue exceeds the corresponding total marginal cost. Using this approach, the annual average number of cycles for the selected technologies was calculated, and the results are summarized in Table 4.

The findings indicate that LFP and flow battery technologies lead in terms of annual average cycle count. Although the cycle efficiency of flow batteries is lower than that of their lithium-ion counterparts, the high total number of allowable cycles over their lifetime reduces the depreciation cost per cycle and enables more frequent operation in the model. Among the evaluated options, NMC technology stands out as having the lowest lifetime cycle capacity; consequently, under the assumptions of higher per-cycle costs and capacity degradation, its cycling frequency is expected to decline in later years. These results demonstrate that technology selection is influenced not only by instantaneous efficiency and capital cost but also by parameters such as lifetime cycle capacity and energy–duration scalability.

Table 4. Projections of Annual Average Cycle Counts for Different Battery Technologies

Storage Technology	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Average
LFP	246	266	290	324	353	371	383	410	436	466	511	369
NMC	108	156	192	245	278	314	326	337	357	385	419	283
Flow Battery (4 hours)	176	213	243	291	323	351	362	382	406	436	486	334
Flow Battery (6 hours)	165	201	231	275	304	334	347	366	382	404	439	314
NaS	139	183	214	266	299	330	340	358	375	405	447	305

As expected, the annual charging volume of the compared technologies increases in parallel with the annual cycle count. However, due to differences in charge–discharge efficiency (η) and the amount of energy delivered per cycle, the annual discharged energy supplied to the grid can vary among technologies. In other words, a higher cycling frequency does not necessarily translate into a higher discharged energy volume, since in the relationship Eout=η×EinE_{\text{out}} = \eta \times E_{\text{in}}Eout=η×Ein, efficiency and the energy per cycle are the determining factors. As shown in Table 4, although NaS batteries exhibit a higher annual cycle count than NMC batteries, the total discharged energy of the NMC technology is greater. This outcome can be attributed to differences in efficiency and/or variations in the amount of energy delivered per cycle.

Table 5. Annual Discharge Volumes (GWh) for Different Battery Technologies

Storage Technology	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Average
LFP	8,7	9,3	10,2	11,4	12,4	13,1	13,5	14,4	15,4	16,4	18	13
NMC	3,7	5,4	6,6	8,4	9,6	10,8	11,2	11,6	12,3	13,2	14,4	9,7
Flow Battery (4 hours)	4,8	5,8	6,6	7,9	8,8	9,6	9,8	10,4	11,1	11,8	13,2	9,1
Flow Battery (6 hours)	6,7	8,2	9,4	11,2	12,4	13,6	14,2	15	15,6	16,5	17,6	12,8
NaS	4,3	5,7	6,7	8,3	9,3	10,3	10,6	11,2	11,7	12,6	14	9,5

The LCOS trends of the evaluated battery technologies for the 2025–2035 period are presented in Table 5. Comparative calculations indicate that, despite NaS batteries having a higher annual cycle count than NMC technology, the total discharged energy of NMC is greater. This difference has been reflected in the LCOS calculation using the annual discharge volumes provided in Table 5, with the results visualized in Figure 2. The findings demonstrate that discharged energy (utilization rate) and cycle efficiency are key determinants of LCOS, and that the cycle count alone does not guarantee a lower service cost. From the perspective of a grid-scale, standalone storage facility, Lithium Iron Phosphate (LFP) technology stands out as offering the lowest service cost. This advantage is associated with (i) a relatively low capital expenditure (CAPEX), (ii) reasonable annual cycling performance, and (iii) high charge–discharge efficiency (η), which effectively reduces the cost of charging electricity. Overall, the results confirm the interaction between the main components of LCOS—capital recovery burden, operating expenses, efficiency, and annual discharged energy—and show that, under current assumptions, LFP provides a cost-effective solution.

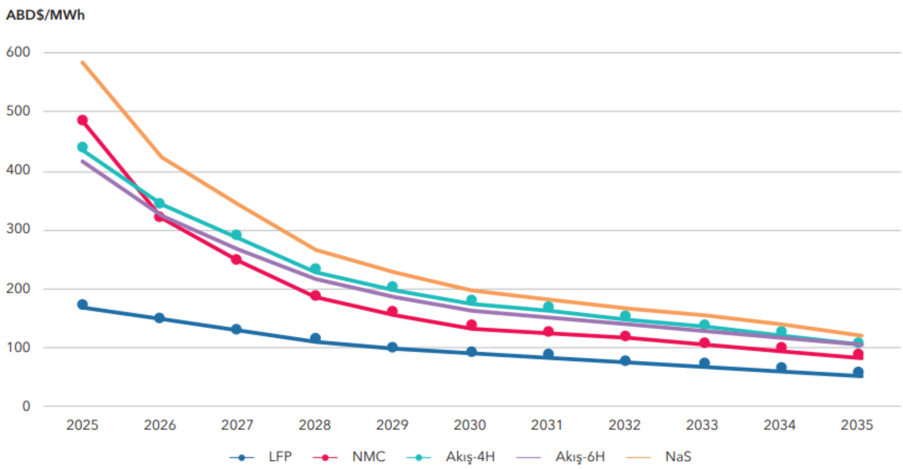

Figure 2. LCOS projections by technology for standalone storage use in arbitrage applications between 2025 and 2035

Figure 3 presents the consolidated hourly projections of the annual average charge/discharge volumes for the years 2025, 2030, and 2035. This visualization does not represent a "typical day" profile but rather shows the total annual volumes for each hour of the respective year. In other words, for example, the value shown for the 16:00 time slot corresponds to the cumulative sum of all charging volumes and all discharging volumes (reported separately) that occurred at 16:00 over all 365 days of the year. Thus, even if some days at the same hour involved charging and others involved discharging, the graph displays these two flows separately on distinct axes as annual cumulative magnitudes.

The findings indicate that in 2025, charging volumes were concentrated predominantly during midday hours, whereas by 2030 and 2035 they extend over a broader portion of the day. This temporal expansion is driven by two key factors: (i) the increase in renewable generation penetration, which causes zero or very low-price hours to occur not only at midday but also during other periods of the day (merit-order effect), and (ii) the reduction in battery investment costs, which lowers the price differential threshold required for profitable arbitrage. As a result, economically viable opportunity windows increase in both hourly and daily terms, raising the likelihood of batteries performing multiple cycles within a single day and leading to higher cumulative volumes distributed across the entire year.

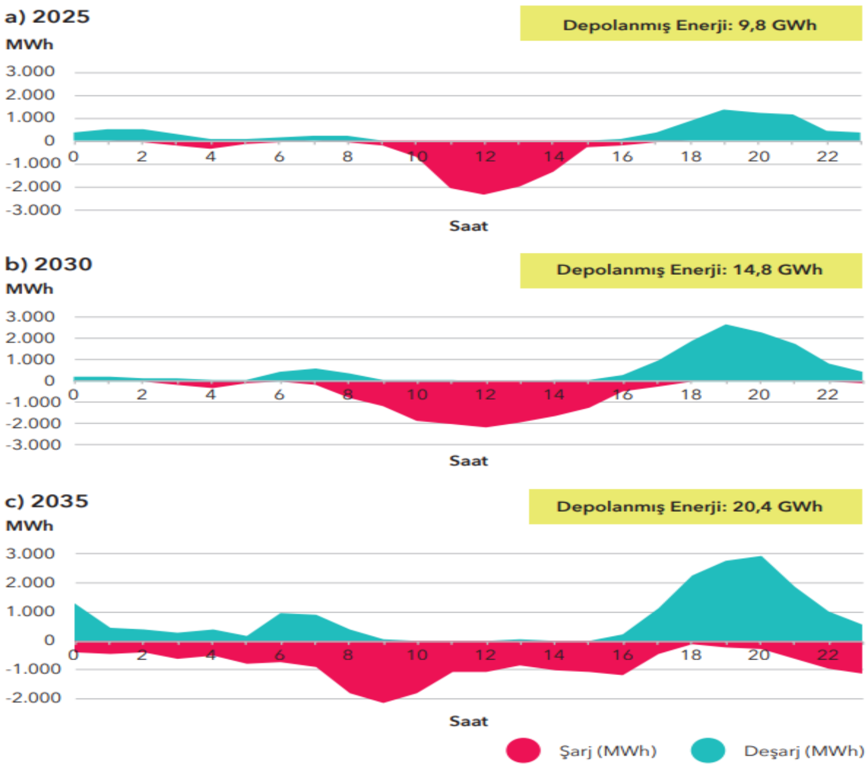

Figure 3. Charge and discharge volumes (MWh) for a 10 MW LFP battery storage facility with a 4-hour charge/discharge capacity – Annual averages on an hourly basis

Figure 4. Hourly distribution of charging opportunities over time for an LFP lithium-ion battery with a 4-hour energy duration The figure depicts the intraday temporal distribution of charging probability, computed over annual cumulative hours. In 2025, charging windows concentrate predominantly around midday. With rising renewable generation penetration—leading to lower marginal prices and a greater incidence of zero-price hours—chargeable hours spread into the daytime band (07:00–15:00) by 2030 and expand further to include nighttime hours by 2035. In market settings where negative prices are possible, charging behavior follows a similar pattern, remaining clustered around the midday interval where negative prices are most prevalent.

Saat	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
0	0	0	0	0	0	1	1	1	3	3	11
1	1	1	0	1	2	1	1	5	7	9	10
2	5	3	2	2	3	6	6	9	12	14	15
3	8	7	3	3	4	8	11	15	18	20	12
4	4	3	1	0	1	2	4	5	11	12	19
5	1	1	0	0	0	1	0	3	3	5	18
6	0	0	1	2	3	5	7	9	11	14	22
7	2	2	4	7	11	20	28	35	36	38	44
8	4	4	5	8	16	31	40	45	51	52	53
9	18	21	27	31	43	48	41	46	44	48	45
10	51	57	64	66	64	50	41	35	33	32	27
11	58	65	71	73	67	54	42	35	38	32	27
12	49	55	63	69	61	48	42	31	29	22	22
13	34	34	36	40	43	42	43	38	31	35	26
14	7	7	9	11	17	31	36	35	35	31	27
15	4	4	6	9	11	13	21	31	28	30	30
16	1	1	1	3	6	7	8	11	10	12	11
17	0	0	0	0	0	0	1	0	1	1	2
18	0	0	0	0	0	0	1	0	1	1	6
19	0	0	0	0	0	0	1	0	2	3	6
20	0	0	0	0	0	0	0	1	2	6	15
21	0	0	0	0	0	0	3	7	11	15	24
22	0	0	0	0	0	3	4	11	16	22	28
23	0	0	0	0	0	1	2	2	4	8	10
Toplam	246	266	290	324	353	371	383	410	436	466	511

Figure 4. Projected total annual number of charging events for LFP lithium-ion batteries over time (4-hour capacity)

Figure 5 summarizes the profitability dynamics over time by jointly evaluating the Levelized Cost of Service (LCOS) and the average revenue per unit of discharged energy. Increasing renewable generation penetration drives midday marginal prices downward while widening the price differential (spread) between midday and evening hours. This price divergence is the primary mechanism that increases the average revenue earned per battery cycle. Simultaneously, declining investment costs and rising annual discharge volumes exert downward pressure on LCOS. The model results indicate that, due to the combined effect of these factors, standalone storage applications surpass the economic threshold for pure price arbitrage by 2034—meaning that the condition unit revenue ≥ LCOS is met (Figure 5). This finding highlights that economies of scale and renewable-driven price dynamics significantly enhance the financial feasibility of storage investments.

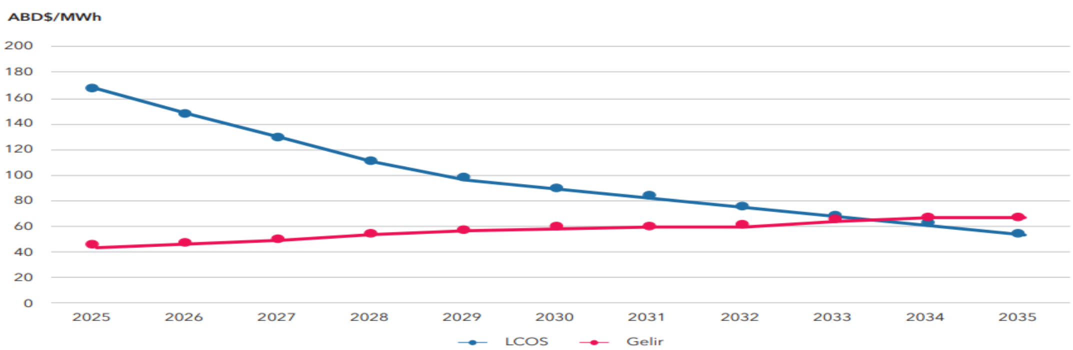

Figure 5. Projection of LCOS and unit revenue levels for an LFP lithium-ion battery with a 4-hour charge/discharge duration

5. Cost – Benefit Analysis of Rooftop Pv and Battery Storage Installation

5.1. Standalone Storage Consumer Profile

In this scenario, it is assumed that the household simultaneously owns a rooftop photovoltaic (PV) system and a battery energy storage unit. The sample consumer's hourly annual electricity demand profile (Başkent EDAŞ distribution region) was derived from data provided by the Transparency Platform of the Energy Markets Operation Company (EPİAŞ). Annual consumption is assumed to be 3,000 kWh (250 kWh per month), met by a 2 kWp rooftop PV system. The storage power was set at 0.4 kW, corresponding to 10% above the average demand during the evening peak period (17:00–22:00), with an energy duration of 4 hours. Considering space constraints, and due to its higher energy density advantage, the NMC lithium-ion technology was selected for the residential application.

The analysis focuses solely on the cost–benefit evaluation of the storage asset; revenues from direct sale of PV-generated electricity to the grid are excluded. Instead, arbitrage revenues from storing PV-generated electricity and selling it in later hours are considered. Thus, the calculations capture both the additional returns (arbitrage) provided by the storage facility and the associated investment and operating costs.

The storage unit can be charged either from the grid or from its own PV generation. When storing self-generated electricity, no distribution tariff is applied; therefore, operational rules prioritize charging from PV. If spare capacity remains, the unit is charged from the grid. This approach enables the redirection of PV energy—which would otherwise be exported to the grid during midday low/zero-price periods—towards meeting evening demand. In this respect, the scenario differs from a configuration without PV, in which the storage system is solely integrated with consumption.

Under the stated assumptions, the model was run at hourly resolution for the 2025–2035 period (Table 6). The results indicate that, on average, 18% of rooftop PV generation is stored and subsequently directed to consumption or sale in later hours. With the decline in market prices during midday, the volume of generation directly exported to the grid decreases significantly; in cases where prices occasionally fall below the distribution tariff, curtailment rates increase. This finding confirms that, with growing renewable generation, the low-price regime observed during midday hours enhances the role of storage and makes self-consumption or deferred sale strategies economically more attractive than immediate export.

Table 15. Rooftop PV and NMC Battery Installation Results for Residential Applications (PV: 2 kW, Storage: 0.4 kW / 1.6 kWh)

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Avg.
Annual Consumption (kWh)	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000	3000
Consumption from Generation (kWh)	1322	1323	1322	1323	1321	1319	1319	1320	1319	1318	1317	1320
Consumption from Storage (kWh)	492	493	493	494	494	499	505	518	542	572	621	520
Consumption from Grid (kWh)	1186	1184	1185	1183	1185	1182	1176	1162	1139	1109	1062	1159
PV Generation (kWh)	3150	3150	3150	3150	3150	3150	3150	3150	3150	3150	3150	3150
Direct Consumption from Generation (kWh)	1322	1323	1322	1323	1321	1319	1319	1320	1319	1318	1317	1320
Export to Grid from Generation (kWh)	999	912	711	473	282	170	120	84	69	56	53	357
Charge to Storage from Generation (kWh)	570	571	572	573	571	573	575	575	576	574	574	573
Curtailment (kWh)	260	343	544	785	975	1086	1135	1176	1186	1201	1204	900
Battery Cycle Count	355	357	356	358	357	361	365	374	392	415	452	377
Charge to Storage from Grid (kWh)	1	2	2	3	3	7	12	28	56	93	152	33

The LCOS values calculated for this model, along with the unit revenue provided by storage, are presented in Figure 6. Notably, due to the decline in investment costs, storage investment becomes economically viable by 2031.

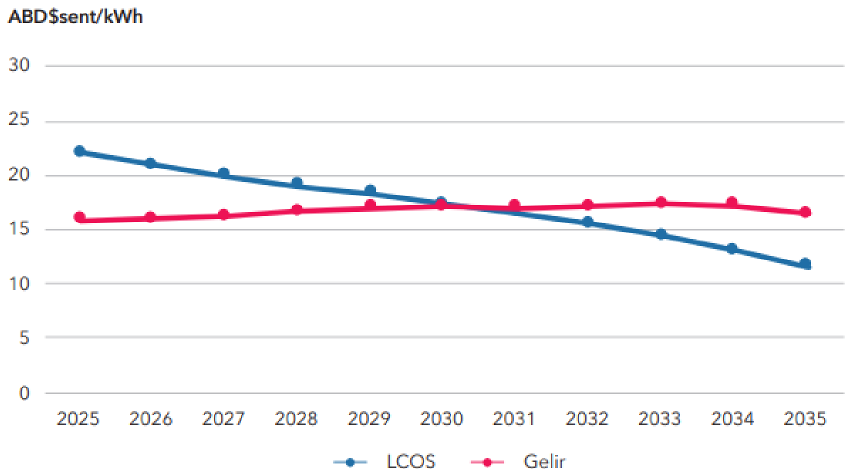

Figure 6. Comparison of LCOS and revenue per unit of discharged energy for a behind-the-meter NMC battery installation

Figure 7. Hourly consolidated annual charge–discharge volumes for 2025, 2030, and 2035, based on the operational priority sequence: (i) direct self-consumption from rooftop PV, (ii) charging the battery with surplus PV generation, and (iii) discharging from the battery during peak hours, with any residual demand met from the grid. Under this operational framework, grid charging of the battery remains minimal.

In 2025, the consumption mix comprises 44% direct PV generation, 16% PV energy stored and later discharged from the battery, and 40% grid supply. Of the PV generation not stored, 32% is exported to the grid and 8% curtailed. By 2035, the consumption proportions remain largely similar; however, only 2% of PV generation is exported to the grid, while curtailment rises to 38%. This substantial increase in curtailment is primarily attributed to midday market prices falling below the distribution tariff, making grid export uneconomical. In such instances, PV output is curtailed once storage capacity is full rather than being exported.

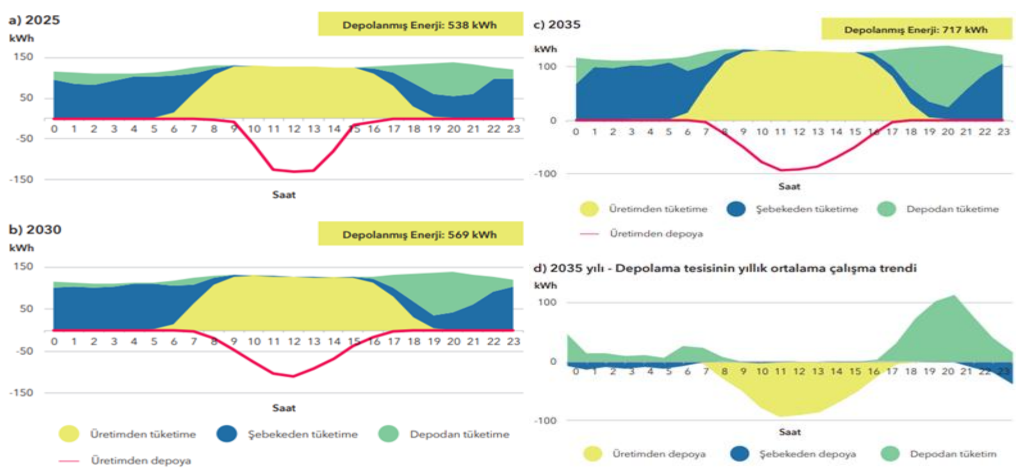

Figure 7. Hourly profiles (annual consolidated hourly basis) for residential rooftop PV (2 kW) and NMC battery (0.4 kW / 1.6 kWh) usage)

6. Cost – Benefit Analysis of Batteries in the Ancillary Services Market

6.1. Frequency Control

Lithium Iron Phosphate (LFP), Nickel–Manganese–Cobalt (NMC), flow batteries, and Sodium–Sulfur (NaS) technologies are technically well-suited for Frequency Control (FC) services due to their ability to respond on a millisecond scale. However, for flow batteries to participate in FC instantaneously, their pump circuits must be in operational mode; when pumps are not already running, the activation time can extend to up to 10 seconds. With prior notification of FC demand, flow systems can be kept in a ready state to ensure timely response. Similarly, NaS batteries can deliver fast response performance provided that the required pre-heating conditions are met.

Since Frequency Control (FC) is a capacity service aimed at correcting small frequency deviations in both upward and downward directions, it typically does not require full charge–discharge cycles; the associated energy flows during this process are negligible. Consequently, in technology selection, variables that are critical for energy services—such as cycle efficiency and lifetime cycle count—become secondary considerations, while the primary determinant shifts to capital expenditure (CAPEX). Within this framework, the relatively lower investment cost of LFP technology makes it a rational choice for FC services.

At the system level, considering TEİAŞ's Frequency Control (FC) capacity requirement of 334 MW for 2024 and comparing it with the projected 7,200 MW total battery storage capacity in 2035, FC is seen to occupy only a limited share of the overall storage portfolio. As the market deepens in this area, competition for FC demand is likely to intensify, potentially leading to a decline in unit profitability over time. Therefore, in FC-focused investment decisions, it is important to complement the advantage of low CAPEX with scenario analyses that assess the saturation risk in service revenues.

7. Reducing Imbalance Costs

According to Article 110 of the Electricity Market Balancing and Settlement Regulation, production and consumption imbalances, along with the related penalties, are calculated using specific formulas.:

Excess Generation Sale Price = min(PTF, SMF) ∗ 0.97 (PTF: Day-Ahead Market (GÖP) Market Clearing Price)

Deficit Generation Purchase Price = max(PTF, SMF) ∗ 1.03 (SMF: Balancing Power Market (DGP) System Marginal Price)

In Türkiye, imbalance pricing is applied symmetrically for positive and negative deviations, as defined in the regulations; in the case of excess or deficit generation, a disadvantageous unit price is imposed on the producer, incorporating a penalty of approximately 3%. The potential of battery systems to reduce imbalance costs depends primarily on the scale of the facility's current annual exposure to imbalance. Considering that, under current market conditions, imbalance-related expenses account for less than approximately 1% of plant revenues, a storage investment focused solely on imbalance management does not appear financially rational in isolation.

However, with the increase in the share of variable-output resources in line with net-zero targets, the importance of imbalance management in system operation is expected to grow; accordingly, more stringent penalty parameterizations may be introduced. In this context, power plants integrated with battery storage not only enhance grid flexibility and facilitate operation but also provide an effective tool for reducing real-time imbalances. Therefore, the feasibility of storage investments should be evaluated from a holistic "value-stacking" perspective (including arbitrage, ancillary services, capacity/reserve payments, etc.) rather than solely on the basis of imbalance costs.

8. Conclusion

The results indicate that Lithium Iron Phosphate (LFP) technology stands out operationally due to its high cycle efficiency of approximately 92% and millisecond-scale response capability. A moderate cycle loss of around 12% and an estimated lifespan of 5,000 cycles contribute to stable long-term operating costs. Nickel–Manganese–Cobalt (NMC) chemistry achieves a comparable efficiency range (90–95%); however, its relatively shorter service life (~2,000 cycles) and higher cycle loss (~14%) may limit long-term cost-effectiveness. Vanadium redox flow batteries, despite their low energy density, offer a strategic advantage for grid-scale and long-duration applications with a lifetime exceeding ~15,000 cycles and an energy duration of about 20 hours. Nevertheless, their cycle loss can reach up to 32%, and their efficiency (75–85%) may restrict performance in short-duration, high-efficiency tasks. Sodium–Sulfur (NaS) systems, with an efficiency range of 75–80% and ~6 hours of energy duration, appear competitive for long-duration use; however, a 22% cycle loss and high operating temperature requirements increase both investment and maintenance costs. Overall, these findings suggest that each technology offers distinct cost–benefit trade-offs depending on the application context: lithium-ion–based solutions (particularly LFP) are more suitable for short-duration, high-efficiency services, whereas flow batteries present a more rational choice for applications demanding long life and extended duration.

Under the current tariff structure, storage facilities are subject to transmission and distribution charges for both energy intake and energy injection. Considering the system-level externalities of storage—such as reducing renewable curtailment, substituting fossil fuel generation, and deferring grid infrastructure investments—it is recommended to design a dedicated network tariff for storage assets and implement reduced grid charges. Such regulatory adjustments would lower the total cost of ownership for storage investments, thereby enhancing their economic feasibility.

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