BA-CS-085

REV: April 27, 2026

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Strategic Repurposing of an EV Gigafactory

Introduction

It is January 2026. You are the CEO of VoltCell North America, a joint-venture gigafactory established in 2021 by a North American automotive OEM and a Korean cell manufacturer. You are sitting at a table with the Vice Presidents of Materials, Finance, and Operations. The JV Board Chair has just left the room. The mandate she handed you is precise and non-negotiable: return to this table in sixty days with a transformation roadmap for the gigafactory. The JV Board meets in March.

The plant was commissioned between 2021 and 2024 at a cost no one in the room wants to say out loud. Fifteen gigawatt-hours of capacity. High-Nickel Manganese Cobalt (NMC) cylindrical cells. Automated winding lines that can spin a 2170 cell in under a second. Dry rooms held at a dew point of -40°C. Formation chambers built for automotive throughput. Every piece of equipment justified by a demand forecast that, by late 2025, had stopped being a forecast and had become a fiction.

VoltCell's sole customer is the OEM parent, MotorCo, which had contracted to offtake the full fifteen gigawatt-hours annually under a long-term supply agreement signed in 2021. The plant is running at sixty to sixty-five percent utilization. EV sales in the United States fell by 41% in January 2026, the first full month after the federal seven-thousand-dollar tax credit expired. MotorCo's ramp-up has been running twelve months late since 2024, and the OEM has now formally notified VoltCell of a further volume reduction, citing a long-term demand revision that lowers their EV programme targets through 2028. The contracted take-or-pay fee provides partial protection, but it does not cover the fixed cost at the current utilisation

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Manan Parikh, Ricardo Chavez, Tony Guillon, prepared the original version of this note "Strategic Repurposing of an EV Gigafactory" BA No. BA-CS-085, reviewed by B.A Mariano Rubio & Dr. Garima Shukla, as the basis for class discussion. Only for B.A BatteryDay 2026 Open Case Study session on 28.04.2026..

level. The original business plan is no longer recoverable on its existing terms. The fixed cost per kilowatt-hour has risen accordingly. The Board is asking questions that asset-heavy manufacturers dread: Is this a cycle, or a structural reset? And if it is structural, what do you do with fifteen gigawatt-hours of high-nickel cylindrical capacity in a world that is moving elsewhere?

There is, however, a second story running alongside the first. The U.S. grid storage market installed 4.6 GW and 13.6 GWh in the third quarter of 2025 alone, a 27% year-on-year increase. The Foreign Entity of Concern (FEOC) provisions in the One Big Beautiful Bill Act (OBBBA) have just made Chinese-manufactured cells ineligible for the Investment Tax Credit (ITC), creating a domestic supply gap that will not close before 2027. Your plant, with its electrode-coating lines and formation capacity, sits at the intersection of two market signals that point in opposite directions.

The question the CEO has asked is not whether to act. It is which form of action to take, at what cost, on what timeline, and with what strategic logic. This case gives you the information your team assembled. The decision is yours. Four questions frame the committee’s work: how to sequence the chemistry and format transformation; how to resolve the Lithium Iron Phosphate (LFP) cathode sourcing constraint; who the next anchor customer is and how to structure that relationship; and whether the plant architecture supports a hybrid solution or demands a single committed path.

Questions

1. Given the OEM’s financial constraints and the existing line architecture, should the team pursue a rapid NMC-to-LFP chemistry switch to quickly recover utilisation, or commit to a full format conversion to capture ESS demand structurally? What conditions determine the right sequence, and what would need to be true to change that answer?

2. LFP cathode supply is China-dominated and FEOC-restricted from 2026. Should the JV accept transitional Chinese sourcing, pursue a non-China JV or licensing route, or commit to domestic insourcing? What does each path cost in IRA credit exposure, and what is the realistic timeline for each?

3. MotorCo is no longer a reliable anchor customer. For the transformation to be financeable, the JV must identify and secure a new primary buyer before or during capex deployment. Who is the target customer for the transformed plant, and what contract structure, volume commitment, and pricing terms are required to make the JV Board approve the investment?

4. If the plant is structured as three parallel five GWh lines, converting one line to prismatic LFP ESS while maintaining two cylindrical lines for MotorCo is operationally coherent. If not, hybrid operation requires setting up a structurally new line. Which architecture does the plant actually have, and does that change which scenario is viable? What is the decision rule for when to convert the remaining lines?

1. The Market Inflexion: Two Forces in Tension

The gigafactory was designed for a market that no longer exists in the form originally projected. Between 2020 and 2023, the trajectory of U.S. electric vehicle adoption looked inevitable. Sales grew rapidly, federal incentives were generous and expanding, and OEM capital allocation followed the demand curve upward.

What arrived instead was a plateau. U.S. EV sales reached approximately 1.2 to 1.3 million units in 2025, representing roughly 7-8% of total light-duty vehicle sales — well below forecasts of 15% or more penetration. Several forces converged: tightening IRA eligibility requirements and emphasising domestic content and FEOC-compliant sourcing reduced the number of qualifying models; higher interest rates raised monthly financing costs; and consumers increasingly favoured leasing over purchasing, compressing OEM residual value assumptions. The defining event was the expiry of the seven-thousand-dollar federal purchase credit on September 30, 2025, which created a sharp third-quarter pull-forward and a fourth-quarter demand collapse.

For a plant built around optimistic volume assumptions, the arithmetic of underutilization is punishing. A plant with 15 GWh of nameplate capacity operating at 60% utilisation produces only 9 GWh annually. Fixed costs remain largely unchanged, but are now absorbed by a third less output, raising the effective cost per unit produced. The competitive backdrop intensifies the pressure. Chinese manufacturers, operating at scale with vertically integrated supply chains, achieved cell-level LFP costs of $55- $65 per kWh in 2025 — materially below U.S. domestic production costs, even with Inflation Reduction Act (IRA) manufacturing credits under Section 45X (Advanced Manufacturing Production Credit).

Against this, the grid storage market presents a structurally different demand signal. U.S. utility-scale battery storage installations hit a quarterly record in mid-2025. Early-stage capacity was added in the Midcontinent Independent System Operator (MISO) and PJM Interconnection (PJM). Renewable intermittency, AI-driven data centre load growth, and state procurement mandates are all structural tailwinds. Unlike consumer EV demand, which is sensitive to interest rates and incentive structures, grid storage demand is largely driven by utility planning cycles, capacity market obligations, and renewable integration requirements.

The chemistry preference in grid storage is LFP. Energy density matters less when the asset sits in a parking lot-sized container than when it must fit under a vehicle seat. What matters is cost per kWh, cycle life, and thermal stability. LFP delivers all three. The FEOC provisions now make Chinese-manufactured LFP ineligible for the ITC on storage projects, creating a compliance-driven demand signal for domestic or non-FEOC LFP cell supply.

See Exhibit A (U.S. Battery Capacity Map) and Exhibit B (EV vs Energy Storage System (ESS) Compound Annual Growth Rate (CAGR) Forecast 2024 to 2030).

2. The Plant and Its Constraints

Before selecting a transformation path, the team needs to understand what the plant can realistically convert to, and at what cost. Battery manufacturing is capital-intensive and tightly sequential: a change in chemistry, format, or end-use application triggers adjustments across the entire production process, from slurry formulation and electrode coating to cell formation and quality testing. These interdependencies determine both the cost and the timeline of any conversion.

The protagonist plant was engineered around high-nickel NMC cylindrical cells, specifically the 2170 format. Cathode slurry is prepared using N-Methyl-2-pyrrolidone (NMP), a solvent whose viscosity must be controlled between 1,000 and 3,000 millipascal-seconds during electrode coating. Drying ovens operate in the 120-150°C range. Calendering pressures exceed two hundred to three hundred megapascals (MPa) to achieve electrode densities above 3.5 grams per cubic centimetre. Moisture control in dry rooms is maintained below minus forty degrees Celsius dew point. Formation protocols are tuned to NMC electrochemistry. Every parameter is optimised for a single chemistry and a single format.

The U.S. battery manufacturing landscape provides context for the plant. Between 2021 and 2024, more than a thousand GWh of battery cell manufacturing capacity was announced in North America. As of 2026, operational capacity is substantially lower, with ramp rates constrained by workforce availability, yield learning curves, and demand variability. Plants dedicated to high-nickel cylindrical EV cells appear more exposed to demand volatility than facilities producing LFP for diversified applications. The protagonist plant sits precisely in the most exposed segment of this landscape.

See Exhibit E (Process 4M Matrix).

The Chemistry Constraint

A transition from high-nickel NMC to LFP primarily affects the electrode manufacturing stage. LFP cathode slurry is compatible with water-based binders, reducing dependence on NMP solvent recovery systems. Calendar pressure decreases to one hundred to two hundred MPa due to LFP's lower intrinsic density. Formation times can shorten by 5-10 % due to LFP's greater electrochemical stability. Equipment reuse at the electrode stage can exceed 80-95%. The chemistry transition is the least capital-intensive transformation pathway.

The material cost implication is significant. High-nickel Cathode Active Material (CAM) costs exceed \$25–\$30 per kWh. LFP cathode active material costs \$12–\$18 per kWh. The delta, fifteen to twenty-five dollars per kWh, is a structural cost advantage that does not depend on volume assumptions. At 15 GWh of nameplate capacity, even a \$ 20-per-kWh improvement translates to a \$300 million annual cost differential at full utilisation.

The Format Constraint

Format conversion introduces a different class of constraint. Cylindrical to prismatic conversion is not a chemistry question: it is a capital question. Winding systems, cylindrical casing equipment, crimp sealing lines, and electrolyte filling systems are all geometry-specific. Replacing them with stacking equipment, prismatic housing integration, laser welding systems, and pouch or prismatic sealing lines requires a capital investment in the two hundred and fifty to four hundred million-dollar range and the write-off of two hundred to three hundred and fifty million dollars of existing winding infrastructure. It also requires a production stop at the assembly stage for 18 to 30 months. Prismatic cells offer 15-20% better volumetric packing efficiency in standard twenty-foot container-based ESS installations, driven by the elimination of inter-cell dead space inherent to cylindrical geometry. Prismatic LFP lines designed for ESS achieve scrap rates below 1% in mature operation, compared to 1-2% for mature cylindrical NMC lines and a transient premium of 2-4% during LFP cylindrical ramp-up on a converted NMC line. See Exhibit G (Capex and Write-Off Sensitivity).

3. The Supply Chain Inflexion

Changing battery chemistry is not purely a manufacturing decision. At its foundation, it means exiting one supply chain and entering another, with different raw material sources, processing partners, and geopolitical risk profiles. The NMC chain inherited its architecture from the electronics industry: high-value, precision-processed materials sourced from a geographically concentrated supplier base. The LFP chain was built in China from the ground up, optimised for cost and scale.

The NMC Chain: Price Volatility as a Structural Tax

NMC production relies on cobalt, nickel, and manganese, each carrying its own risk profile. Approximately 70% of global cobalt supply flows through the Democratic Republic of Congo (DRC). Artisanal mining practices and Environmental, Social, and Governance (ESG) concerns in that region add complexity to supplier qualification and increase manufacturers' reputational exposure. Nickel prices have shown two- to threefold volatility over five-year cycles. Lithium hydroxide refining — the lithium salt required for NMC — is heavily concentrated in China. Precursor Cathode Active Material (pCAM) blending is concentrated in China, Korea, and Japan; Cathode Active Material (CAM) production for NMC is dominated by Korea and Japan, providing a viable non-China supply path. The NMC chain is expensive, volatile, and carries Environmental, Social and Governance (ESG) exposure, but it has established FEOC-compliant alternatives outside China.

The LFP Chain: Eliminating Cobalt, Concentrating Control

LFP replaces cobalt and nickel with iron and phosphate, and substitutes lithium carbonate for the lithium hydroxide required in NMC. Iron and phosphate are commodity materials, widely available and price-stable. Lithium carbonate is available from South America at the lower end of the cost curve. These substitutions eliminate ESG exposure to DRC cobalt and nickel price volatility. However, the LFP chain was built in China, and the carbon coating process essential for LFP conductivity — the step that transforms iron phosphate powder into functional cathode material — is dominated by Chinese intellectual property and manufacturing capacity. Non-China LFP CAM producers exist (L&F in Korea, Posco Future M in Korea, Mitra Chem in Michigan, ICL with Aleees in St. Louis), but their combined capacity is a fraction of Chinese output. LFP replaces one set of supply chain risks with another. It does not eliminate supply chain risk.

LFP replaces cobalt and nickel with iron and phosphate, and substitutes lithium carbonate for the lithium hydroxide required in NMC. The LFP chain also introduces the emerging Lithium Manganese Iron Phosphate (LMFP) chemistry, which adds manganese to improve energy density while retaining LFP's cost and safety advantages. LMFP is not yet at commercial scale but represents a potential future upgrade path for a converted LFP plant.

China Export Controls: The Compliance Window Closes from Both Sides

In July 2025, China placed fourth-generation LFP cathode technology, defined as having a compaction density above 2.58 grams per cubic centimetre, on its export control list. This means that Chinese firms must now obtain a licence before exporting the most advanced LFP production technology to non-Chinese manufacturers. The practical implication is that companies attempting to build non-China LFP cathode production using Chinese technology transfer or Chinese engineering support face new regulatory risks. And the BTR New Material Group (BTR) precedent, in which a Chinese graphite supplier was designated a FEOC by U.S. regulators, illustrates that FEOC designation can be applied to individual companies, not just countries. The compliance window is narrowing from both directions: U.S. FEOC rules are tightening, and Chinese technology export controls are expanding.

The Cost of Non-Compliance: Quantifying the ITC Dependency

Every scenario in Section 4 assumes ITC eligibility. That assumption hinges on FEOC compliance and IRA credit continuity. The standalone battery storage ITC provides a 30% investment tax credit on qualifying storage projects. For a utility-scale ESS developer, ITC eligibility is the difference between a bankable project and a marginal one — typically three to five Internal Rate of Return (IRR) percentage points on the project side. Cells from an FEOC non-compliant source disqualify the storage project from ITC. This means the cell manufacturer's FEOC status directly affects its customers' project economics, which in turn affects willingness to pay and offtake pricing. A non-compliant cell producer selling into the U.S. ESS market after 2026 is not simply leaving credits on the table: it is structurally disadvantaged in a market where compliance is a procurement requirement.

Three Sourcing Pathways: Speed, Compliance, and Capital

Three architectures are available, each trading off compliance speed against capital and risk. The first, accepting Chinese cathode sourcing in the near term, is fastest and cheapest but forfeits ITC eligibility from 2026 and creates reputational and regulatory risk. The second, sourcing from non-China producers in Korea, Japan, Morocco (via LG Chem's Huayou JV), or emerging U.S. producers, is FEOC-compliant but requires twelve to eighteen months lead time and carries a cost premium of five to ten dollars per kWh relative to Chinese CAM. The third, insourcing or JV-ing domestic CAM production, is the most capital-intensive option — an additional investment of three hundred to five hundred million dollars — and takes three to five years to reach meaningful scale, but eliminates supply chain dependency entirely.

The OEM cannot eliminate supply chain risk: it can only choose which type it is willing to manage. LFP reduces commodity price risk at the cost of concentration risk. The FEOC framework makes that concentration risk legally and financially material.

See Exhibit C (Cost Comparison Table), Exhibit D (South American Supply Projections), Exhibit H (Policy Timeline: IRA, Tariffs, and FEOC), and Exhibit I (U.S. LFP Capacity Forecast).

4. Three Transformation Pathways

The advisory team has modelled three distinct transformation pathways. They differ in capital intensity, timeline, risk profile, and strategic optionality. None is without a downside. The task is not to find the safe option: the safe option no longer exists. The task is to choose the risk posture that best matches the OEM's financial position, competitive context, and view of the market through 2030.

Scenario A. Chemistry switch only

Scenario A converts the plant from high-nickel NMC to LFP while maintaining the cylindrical cell format. It is the fastest and least capital-intensive pathway. Cathode slurry systems are reformulated, process parameters are recalibrated, quality systems are requalified, and minor tooling adaptations are made. Equipment reuse exceeds 80-95%. Estimated incremental investment: forty to seventy million dollars. Lead time: six to twelve months, and in many cases executable via a parallel qualification strategy that maintains reduced NMC production while LFP trials proceed, limiting downtime exposure.

The financial case is compelling in isolation. LFP material cost advantage of $15-$25 per kWh, combined with fixed-cost improvements from higher utilisation enabled by ESS market entry, can deliver a structural cost improvement of $25-$30 per kWh. At 12.75 gigawatt-hours of annual output, the gross margin uplift approaches $255 million. In an optimistic scenario with ESS contract capture and 90% utilisation, IRR exceeds 70%. Even in a conservative scenario with a slower utilisation ramp, IRR runs 30-35%. The payback period on a $60 million investment is measured in months, not years.

The constraint is strategic, not financial. Cylindrical LFP cells are technically viable for ESS applications, but the market has standardised on prismatic format for utility-scale storage. Prismatic cells offer 15-20% better volumetric packing efficiency in standard twenty-foot container installations, driven by the elimination of inter-cell dead space inherent to cylindrical geometry. Prismatic LFP also carries a lower scrap rate: mature cylindrical NMC lines run at 1-2% scrap in steady state, but LFP cylindrical qualification on a converted NMC line adds a transient 2-4% scrap premium during ramp. Prismatic LFP lines designed for ESS achieve less than 1% scrap in mature operations. A cylindrical LFP platform can access ESS demand, but it does so at a disadvantage in format relative to the dominant ESS supply chain.

Scenario A is the fastest path to improved unit economics; it is not the fastest path to full ESS market access.

Scenario B. Full format conversion

Scenario B converts the plant from a cylindrical to a prismatic cell architecture while simultaneously switching the chemistry to LFP. It is the highest-capital, highest-disruption pathway. Winding lines are replaced with stacking systems. Casing integration shifts from steel cylindrical cans to aluminium prismatic housings. Welding logic, tab architecture, and mechanical sealing processes are reengineered. The electrode manufacturing lines largely remain, as they are format-agnostic, but the assembly floor undergoes fundamental redesign.

Capital exposure is significant on both sides of the ledger. Write-off risk on winding lines, can insertion systems, and cylindrical sealing equipment ranges from two hundred to three hundred and fifty million dollars. New stacking equipment, prismatic casing lines, and module retooling require $250 to $400 million in new investment. Total capital event: four hundred and fifty to seven hundred and fifty million dollars, depending on scope and whether existing floor space permits parallel installation of new stacking lines before decommissioning of winding systems.

Lead time for full-format conversion ranges from 18 to 30 months, including engineering design, equipment procurement, installation, and commissioning. During the conversion period, if a full production stop is required, utilisation can drop below 50%, temporarily raising the effective fixed cost per kilowatt-hour to between forty and forty-five dollars. The economic viability of Scenario B depends critically on forward ESS offtake commitments that guarantee post-conversion ramp velocity. Without a contracted demand secured before capex deployment, the financial risk of a prolonged low-utilisation transition period is material.

Scenario B delivers the most direct and structurally complete ESS market positioning. A prismatic LFP platform with 15 GWh of capacity, fully FEOC-compliant and with a resolved cathode sourcing strategy, is a competitive asset in the 2027 to 2030 U.S. storage market. The IRR range of 25-45% reflects the wide spread between an optimistic scenario with contracted offtake and a conservative scenario with a slower ramp and cost overrun.

Scenario C. Hybrid expansion

Scenario C is only strategically coherent under a specific plant architecture assumption: that the 15 GWh facility is structured as three parallel 5 GWh assembly lines, with two fully commissioned and a third in late-stage commissioning or recently started. This modular architecture, common in JV gigafactories designed for phased ramp, allows one line to be converted to prismatic stacking while the other two continue cylindrical NMC production for the existing OEM customer, MotorCo. Total capacity is preserved; format is bifurcated. The shared upstream electrode manufacturing backbone serves both streams. Total plant capacity expands toward twenty to twenty-five gigawatt-hours as the new stacking line is added. Investment ranges from $300 million to $500 million, with electrode infrastructure reuse exceeding 85% and the new capital concentrated in third-line assembly conversion and prismatic module integration.

The strategic logic is diversification. EV demand volatility is offset by the stability of ESS contracts. If EV demand recovers in 2027 or 2028, the cylindrical lines remain productive. If ESS growth accelerates, the prismatic lines capture it. The plant is not committed to a single market outcome. This optionality has a price: higher total capital intensity than Scenario A, greater operational complexity than either A or B, and a lead time of 18 to 24 months, which is only modestly shorter than a full format conversion.

The financial profile reflects the hybrid character. At a combined annual output above eighteen to twenty gigawatt-hours equivalent, fixed cost per kilowatt-hour can fall below fifteen dollars, materially enhancing competitiveness against imported cells when combined with tariff protection and IRA credits. IRR ranges from 25% to 45%, depending on the ESS contract duration and financing costs. Scenario C has the highest total capital commitment but preserves the most flexibility in the face of an uncertain 2028 to 2030 market outcome. [See Exhibit F. Fixed Cost Sensitivity Model. See Exhibit G. Capex and Write-Off Sensitivity]

The three pathways described above represent the operational inputs to the financial model. Section 5 quantifies the levers that determine whether any of them generate an acceptable return.

5. Financial Impact and the IRA Variable

The financial case for transformation rests on three reinforcing levers: higher utilisation reduces fixed cost per unit; chemistry conversion to LFP lowers material cost; and the IRA credit stack boosts returns for qualifying domestic producers. All three levers must operate simultaneously for the model to work.

The Cost Levers: Utilisation and Chemistry

The utilisation lever is the most immediate and does not require a chemistry decision. Fixed costs currently stand at $35 per kWh at 60% utilisation. At 85% utilisation, the same fixed-cost base delivers approximately $24–$25 per kWh, a $10–$11 structural improvement from utilisation alone. This lever is available in any scenario, including maintaining NMC production, but it requires a demand source to fill capacity. Without the ESS market, the utilisation lever cannot be pulled.

The LFP material cost advantage reinforces the utilisation gain. LFP CAM costs twelve to eighteen dollars per kWh versus twenty-five to thirty dollars per kWh for high-nickel NMC. Combined with fixed-cost improvements, a total structural cost improvement of $25–$30 per kWh is achievable under Scenario A. This brings the domestic LFP cylindrical cost to approximately $85–$100 per kWh before IRA credits, approaching parity with tariff-adjusted Chinese imports.

The IRA Variable: 45X, ITC, and the Cost of Non-Compliance

Section 45X provides a production tax credit of $35 per kWh for eligible battery cells and $10 per kWh for eligible modules, subject to FEOC compliance and domestic content requirements. For a plant producing 12.75 GWh annually, this represents $446 million per year in production credits — the single largest financial variable in the model. The 45X credit phases down beginning in 2030.

The standalone battery storage ITC introduces a second mechanism that indirectly affects the plant through its customers. ESS projects using FEOC-compliant domestic cells qualify for a 30% ITC on the project cost. Developers and utilities factor ITC eligibility into procurement pricing. A cell supplier that cannot offer ITC-eligible products is pricing into a structurally lower-value market segment. The Modified Accelerated Cost Recovery System (MACRS) five-year depreciation schedule applies to qualifying manufacturing equipment, adding another capital-efficiency lever to the investment case.

Scenario Financial Comparison

Scenario A delivers the strongest near-term financial profile. Base-case payback on a $40–$70 million investment is under 12 months at 85% utilisation with an FEOC-compliant LFP cathode. Conservative case payback ranges from 18 to 24 months. IRR range: 30-70% plus, depending on utilisation ramp rate and cathode sourcing cost.

Scenario B's financial case is dependent on offtake contracts. Without a contracted demand underpinning the post-conversion ramp, the four hundred and fifty to seven hundred and fifty million dollar capital event cannot be justified at a portfolio-level discount rate. With ten to twelve GWh of contracted ESS offtake at a price floor supporting eighty-five percent utilization, the IRR range is 25-45%. The spread is wide because the post-conversion ramp is the dominant uncertainty.

Scenario C's financial profile is the most complex to model because it depends on both the ESS offtake for the new prismatic line and the EV demand recovery for the retained cylindrical lines. At a combined output above eighteen to twenty GWh, fixed cost absorption brings the blended cost structure to approximately fifteen to eighteen dollars per kWh fixed cost, competitive even in a conservative IRA credit scenario.

Sensitivity Variables and the Zero-ITC Test

Three variables drive the spread between optimistic and conservative cases across all scenarios. A 30% capex overrun reduces IRR by two to four percentage points across all scenarios. A 24-month utilisation ramp rather than twelve months has a similar impact. And ITC elimination reduces the effective net cell cost by approximately $35–$45 per kWh on the 45X credit, potentially pushing the U.S. domestic cost above the tariff-adjusted Chinese import price. The zero-ITC test is the most important stress test in the financial model. Every scenario must be modelled both with and without 45X credits.

See Exhibit C (Cost Comparison Table), Exhibit F (Fixed Cost Sensitivity Model), and Exhibit G (Capex and Write-Off Sensitivity).

Conclusion

The advisory team has laid out the landscape. The EV demand reset is real, the ESS opportunity is structural, the chemistry economics favour LFP, the supply chain has a FEOC knot that cannot be ignored, and the financial model depends on assumptions that the Board will stress-test hard. What the team has not done is make the decision. That is the work of your committee.

The following four questions are designed to force the kind of commitment that distinguishes a transformation roadmap from a strategic options paper. There is no single correct answer. Different views on EV recovery timing, LFP cathode supply availability, IRA credit continuity, and solid-state commercialisation timelines will lead rational committees to different conclusions. What will be evaluated is not which answer you choose, but whether your answer is specific, internally consistent, and honest about the assumptions it depends on.

Questions

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Exhibits

Exhibit A. U.S. Battery Capacity Map

Operational vs. announced gigafactory capacity in North America through 2026. Source: Clean Investment Monitor Supply Chain Report 2025; Argonne National Laboratory, Quantification of Commercially Planned Battery Component Supply in North America Through 2035, March 2024.

State/Region	OEM / JV Partner	Chemistry	Nameplate GWh	Status (2026)
Tennessee	Envision AESC	LFP	~10 GWh	Operational (LFP retrofit, 2025)
Tennessee / Ohio	GM + LG Energy Sol.	NMC + LFP	35+ GWh	Ramping; LFP lines added
Indiana	GM + Samsung SDI	NMC + LFP (2027)	23 GWh	Under construction
Michigan	Ford BlueOval SK	NMC cylindrical	21 GWh	Ramping
Georgia	Hyundai + SK On	NMC	35 GWh	Ramping
Arizona	LG Energy Solution	NMC	11 GWh	Operational
US Total Pipeline	Multiple	Mixed	~400-500 GWh	~1,000 GWh announced

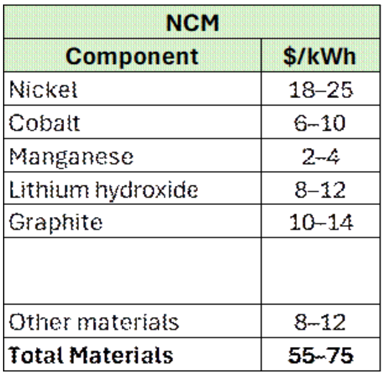
Exhibit B. EV vs ESS Demand Forecast 2024 to 2030

Source: IEA Global EV Outlook 2024; EIA Electricity Storage Forecast; Wood Mackenzie Storage Report.

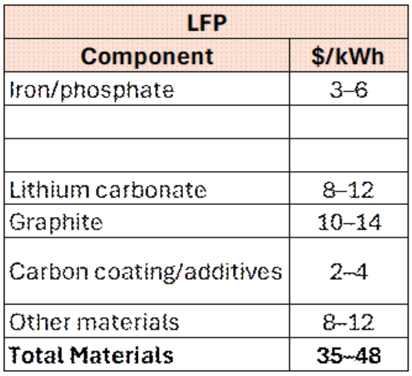
Year	U.S. EV Sales (M units)	U.S. ESS Additions (GWh)	Key Driver
2024	1.2	13-15	IRA incentives; renewable procurement
2025	1.2-1.3	~55 (est.)	BESS boom; FEOC provisions begin
2026	0.8-1.0 (est.)	~49 (OBBBA drag)	Credit expiry; supply chain constraint
2027	1.0-1.2 (est.)	~60 (recovery begins)	Domestic LFP ramp; IRA credits
2028	1.3-1.6 (est.)	80+	Scale; state mandates
2029	1.6-2.0 (est.)	100+	FEOC threshold rises to 75%
2030	2.0+ (est.)	120+ (target)	600+ GWh cumulative (SEIA)

Exhibit C. Cost Comparison Table

Indicative Raw Material-level cost per kWh by chemistry



NCM	
Component	**$/kWh**
Nickel	18–25
Cobalt	6–10
Manganese	2–4
Lithium hydroxide	8–12
Graphite	10–14
Other materials	8–12
Total Materials	**55–75**



LFP	
Component	**$/kWh**
Iron/phosphate	3–6
Lithium carbonate	8–12
Graphite	10–14
Carbon coating/additives	2–4
Other materials	8–12
Total Materials	**35–48**

Indicative cell-level cost per kWh by chemistry and sourcing scenario. Source: BloombergNEF Battery Price Survey 2024; IEA; Reuters; internal modelling.

Configuration	Cell Cost ($/kWh)	ITC/45X Eligible	Key Risk
China LFP (imported)	$55-65	No (FEOC disqualified post-2026)	Tariff escalation; ITC loss
U.S. LFP (IRA-compliant)	$90-110	Yes (30% ITC + 45X)	FEOC cathode sourcing
U.S. LFP (no IRA credit)	$90-110	No	Uncompetitive vs China
U.S. NMC Cylindrical (current)	$110-130	Partial (45X if compliant)	Underutilization; Ni/Co cost
U.S. Prismatic LFP (post-conversion)	$80-100 (at scale)	Yes (if FEOC-compliant)	Conversion capex; ramp time

Comparison of the NMC and LFP Supply Chain, identifying Cost gap and Origin challenges

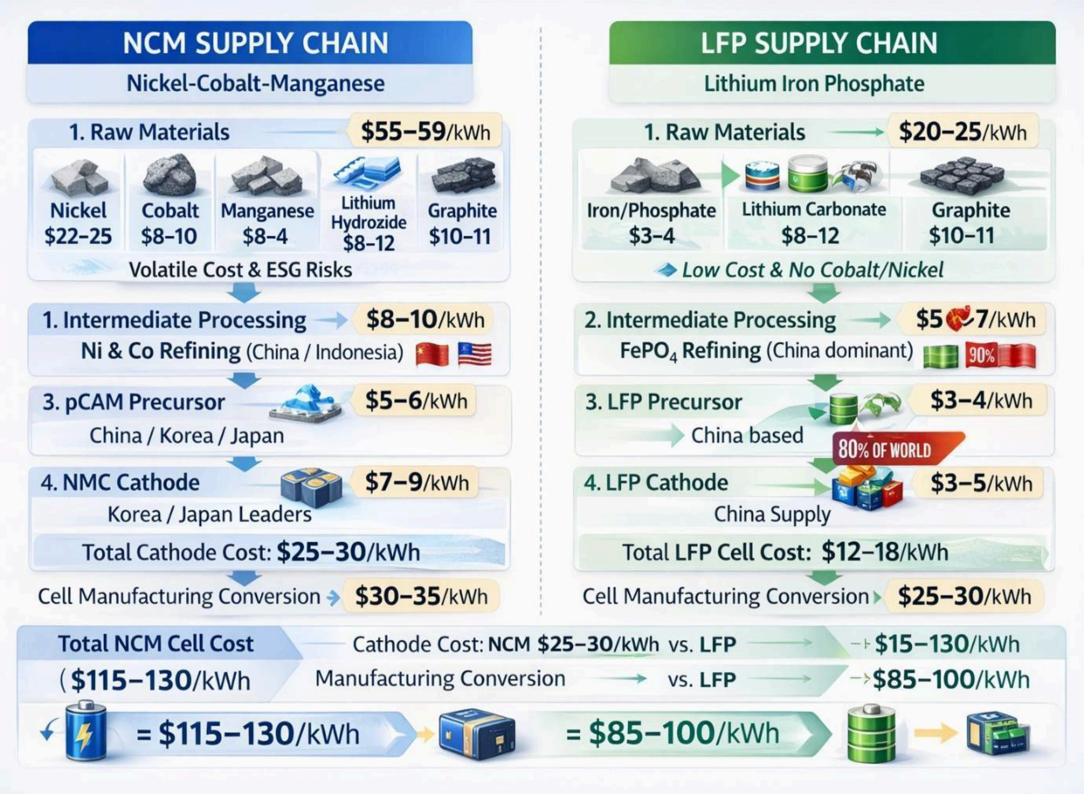
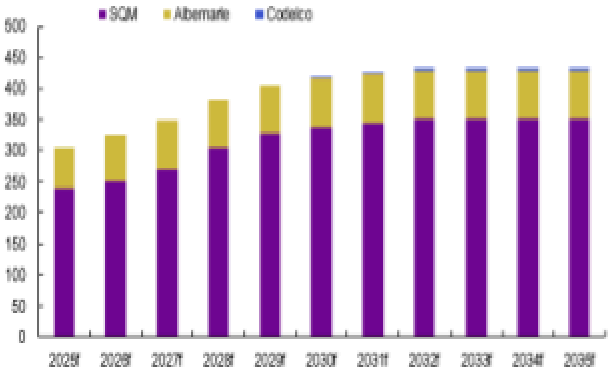


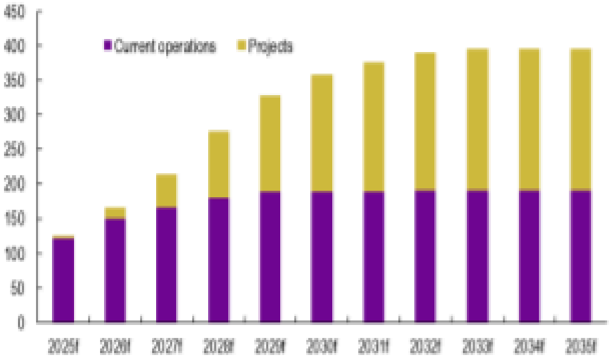
Exhibit D. South American Lithium Supply: Capacity and Projections 2025–2030

The amount supplied from SA worldwide is significant and sufficient to feed North and South American Markets LCE (Lithium Carbonates). The horizon 2030 is showing a gap where extra capacity needs to be determined.

Chile production forecast
'000 tonnes LCE
Source: Fastmarkets



Argentina production forecast
'000 tonnes LCE
Source: Fastmarkets



Global Lithium supply/demand forecast and market balance in LCE
'000 tonnes LCE
Source: Fastmarkets

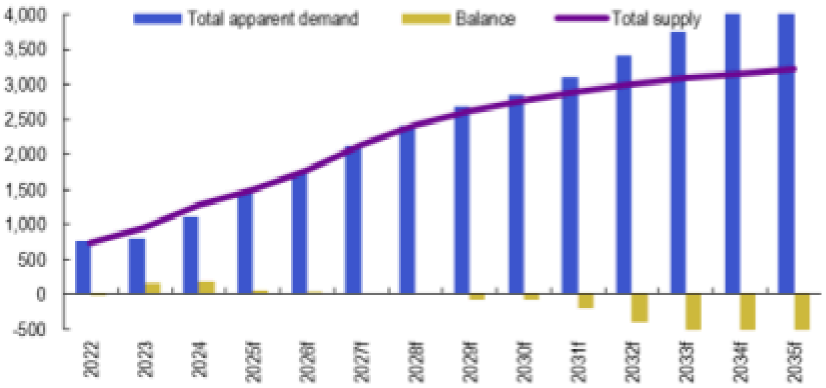


Exhibit E Process 4M Matrix

Manufacturing parameter comparison across transformation scenarios.

Source: Ricardo Chavez process analysis; Battery Associates lecture materials 2025 to 2026.

Process Stage	Current NMC Cylindrical	Scenario A: LFP Cylindrical	Scenario B: LFP Prismatic
Slurry (Material)	NMP solvent; Ni-rich oxide; 1000-3000 mPa-s	Water-based binder option; Fe-PO4; wider viscosity	Same as Scenario A
Coating (Method)	120-150 deg C drying; >200-300 MPa calender	Similar temp; 100-200 MPa calender (lower density)	Same as Scenario A
Cell Assembly (Machine)	High-speed winding; cylindrical casing; crimp seal	Same winding lines; minimal change	Replace with stacking, new prismatic casing; laser weld
Formation (Method)	NMC-optimised algorithms; long formation	LFP algorithms; 5-10% shorter formation	Same as Scenario A
Equipment Reuse	Baseline	80-95%	30-50% (assembly stage write-off)
Capex (incremental)	Baseline	$40-70M	$250-400M new + $200-350M write-off

Exhibit F. Fixed Cost Sensitivity Model

Fixed cost per kWh as a function of annual output at a 15 GWh nameplate plant. Assumes $315M annual fixed cost base (indicative). Source: Internal financial modelling.

Utilization	Annual Output (GWh)	Fixed Cost ($/kWh)	Comment
50%	7.5	$42	Below current format conversion risk period
60% (current)	9.0	$35	Base case today
70%	10.5	$30	Achievable with ESS partial entry
80%	12.0	$26	Scenario A target
85%	12.75	$24.7	Model base case for transformation IRR
90%	13.5	$23.3	Optimistic; ESS contract + EV partial recovery
100% (nameplate)	15.0	$21	Full utilization; structural target

Exhibit G. Capex and Write-Off Sensitivity

Scenario	New Investment	Write-Off Exposure	Net Capital Event	Lead Time	IRR Range
A: Chemistry Switch	$40-70M	Minimal	$40-70M	6-12 months	30-70%+
B: Format Conversion	$250-400M	$200-350M	$450-750M	18-30 months	25-45%
C: Hybrid Expansion	$300-500M	Minimal (EV lines retained)	$300-500M	18-24 months	25-45%

Exhibit H. Policy Timeline: IRA, Tariffs, and FEOC

Source: U.S. Treasury IRA Implementation; USTR Tariff Actions; U.S. Department of Energy; OBBBA text.

Year	IRA 45X Credit	FEOC Threshold (non-FEOC content)	Chinese Battery Tariff	Key Decision Trigger
2025	Active; full rate	55% U.S./non-FEOC required	25% (announced increase)	FEOC compliance deadline approaching
2026	Active	55% required; enforcement begins	25%	Last window for non-compliant sourcing
2027	Active	65% (estimate)	25-30%	Domestic LFP scales; supply gap closing
2028	Under review	70% (estimate)	30%+	IRA renewal debate; election-year risk
2029	TBD (policy risk)	75% required	TBD	Full FEOC enforcement; domestic only viable
2030	TBD	75%+	TBD	Competitive parity decision point

Exhibit I. U.S. LFP Capacity Forecast 2025 to 2030

Source: Clean Investment Monitor 2025; Argonne National Laboratory; Battery Associates analysis.

Year	U.S. Domestic LFP Capacity (GWh)	Key Milestone
2025	10-20	Envision AESC Tennessee LFP launch; first domestic commercial-scale
2026	40-60	FEOC thresholds begin; tariffs rise to 25%; more lines online
2027	80-120	GM-Samsung SDI Indiana LFP production begins; supply gap tightening
2028	120-160	Further scaling, additional retrofits, and IRA compliance pressure peaks
2029	150-180	FEOC threshold rises to 75%; domestic pack production is essential
2030	~200	Full pipeline realised; nearly 200 GWh domestic LFP capacity

Abbreviations and Key Terms

CAGR: Compound Annual Growth Rate. The annual growth rate of an investment over a specified time period longer than one year.

CAM: Cathode Active Material. The functional component of a battery cathode that stores and releases lithium ions during charging and discharging.

CAPEX: Capital Expenditure. Upfront investment in physical assets required to design, procure, and construct or convert manufacturing infrastructure.

DRC: Democratic Republic of Congo. Primary global source of cobalt, a critical raw material in high-nickel NMC battery cathodes.

EPC: Engineering, Procurement and Construction. The contract structure under which a single contractor delivers a complete operational system.

ESG: Environmental, Social and Governance. A framework for evaluating the sustainability and ethical impact of an investment or business operation.

ESS: Energy Storage System. A stationary battery system used for grid-scale applications, including frequency regulation, capacity market participation, and renewable integration.

FEOC: Foreign Entity of Concern. A designation under U.S. law identifying suppliers, primarily from China, Russia, North Korea, and Iran, whose components reduce or eliminate ITC and 45X credit eligibility for battery projects.

FERC: Federal Energy Regulatory Commission. The U.S. federal agency regulating interstate electricity transmission and wholesale electricity markets.

GWh: Gigawatt-hour. Unit of energy equal to one billion watt-hours. Standard unit for expressing battery manufacturing capacity and grid storage deployment.

IEA: International Energy Agency. An intergovernmental organisation providing energy data, analysis, and policy recommendations.

IRA: Inflation Reduction Act (U.S., 2022). Federal legislation providing investment tax credits, production tax credits, and manufacturing credits for clean energy projects and domestic battery production.

IRR: Internal Rate of Return. The discount rate at which the net present value of a project's cash flows equals zero. Primary financial metric for evaluating transformation scenarios.

ITC: Investment Tax Credit. A U.S. federal tax credit equal to a percentage of the eligible basis of a qualifying energy project. For BESS projects, ITC eligibility requires FEOC-compliant sourcing.

JV: Joint Venture. A business arrangement in which two or more parties pool resources for a specific project or business activity.

kWh: Kilowatt-hour. Unit of energy. Standard unit for expressing battery cell costs and electricity storage capacity at the project level.

LFP: Lithium Iron Phosphate. A lithium-ion battery chemistry using iron phosphate as the cathode material. Preferred for ESS applications due to thermal stability, cycle life of 4,000 to 6,000 cycles, and cost advantage over NMC.

MPa: Megapascal. Unit of pressure. Used to express calendering pressure in electrode manufacturing; NMC requires 200 to 300 MPa, LFP requires 100 to 200 MPa.

MISO: Midcontinent Independent System Operator. Regional transmission organisation serving the central United States and Manitoba, Canada.

NMC: Lithium Nickel Manganese Cobalt Oxide. A lithium-ion chemistry with higher energy density than LFP but greater thermal sensitivity and higher cell cost. Dominant chemistry in high-performance EV applications.

NMP: N-Methyl-2-pyrrolidone. A solvent used in NMC cathode slurry preparation. Requires recovery systems due to toxicity. LFP can use water-based binders, eliminating dependence on NMP.

OBBBA: One Big Beautiful Bill Act. U.S. legislation containing provisions that extend and modify FEOC restrictions and ITC eligibility rules for battery storage projects.

OEM: Original Equipment Manufacturer. In this case, the North American automotive company is operating the gigafactory.

PJM: PJM Interconnection. The largest U.S. regional transmission organisation, operating the grid across 13 states and the District of Columbia.

R&D: Research and Development. Investment in scientific and technical work aimed at developing new products or processes.

45X: Section 45X of the IRA. The Advanced Manufacturing Production Credit provides a per-kilowatt-hour production tax credit for eligible battery cells and modules manufactured in the United States.

BTR: BTR New Material Group. A Chinese manufacturer of graphite anode materials and battery components, classified as a Foreign Entity of Concern by the U.S. Department of Energy in January 2025 in relation to its Indonesian subsidiary operations.

LMFP: Lithium Manganese Iron Phosphate. An evolution of LFP chemistry incorporating manganese to improve energy density while preserving thermal stability and cycle-life advantages. Requires manganese sulphate as an additional precursor material.

MACRS: Modified Accelerated Cost Recovery System. A U.S. federal depreciation method allowing accelerated write-down of qualifying assets. Battery storage projects eligible for the ITC typically qualify for five-year MACRS, with the depreciable basis reduced by 50% of the ITC amount claimed.

pCAM: Precursor Cathode Active Material. The intermediate compound is produced by blending and co-precipitating metal sulphates before sintering into the final cathode active material (CAM). A key midstream processing step in both NMC and LFP supply chains.

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