Powering the Future: Economic Considerations of Grid Expansion and Decentralized Solutions

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Abstract

This paper compares the economic and welfare performance of centralized electricity grid extension and decentralized microgrids across heterogeneous geographic contexts. An integrated modeling framework combines project-level cost-benefit analysis (CBA), a stylized computable general equilibrium (CGE) model, and agent-based modeling (ABM) to evaluate financial viability, regional welfare effects, and adoption dynamics. The CBA is calibrated to a representative rural electricity demand of 11 million kWh annually over a 20-year horizon, comparing long-distance grid extension with a decentralized microgrid configuration. Results indicate that grid extension is highly sensitive to transmission distance, yielding negative net present value under baseline assumptions as line construction costs increase. In contrast, the microgrid scenario produces a positive net present value when reliability and avoided outage costs are incorporated. The implied economic break-even distance is approximately 57 miles, beyond which decentralized generation dominates centralized expansion. CGE results show that centralized investments generate modest efficiency gains in urban regions, while decentralized systems produce larger proportional welfare and GDP gains in rural areas due to resilience benefits and local labor effects. ABM simulations further indicate that moderate upfront subsidies significantly accelerate deployment. These findings suggest that policymakers should move away from "one-size-fits-all" strategies in favor of geographically differentiated energy policies that monetize resilience and utilize targeted financial incentives. Regionally differentiated electrification policy aligns infrastructure choice with geographic, economic, and reliability conditions.

Introduction

Electric power systems globally face critical decisions regarding grid infrastructure, energy production, and mitigating risks associated with climate change. In addressing these and other concerns, agents in the energy sector face an important question: *What are the economic trade-offs between centralized grid expansion and decentralized microgrids and battery storage deployment?* This study explores the conditions in which microgrids are economically and socially preferable to traditional grid expansion. This question is crucial for policymakers seeking to implement cost-effective and sustainable electrification strategies.

Approximately 860 million people worldwide lacked electricity access as of 2019, necessitating around $51 billion in annual investment to achieve universal access by 2030, with decentralized microgrids anticipated to supply nearly 40% of new connections (Gokhale-Welch & Beshilas, 2020). In developed regions, reliability concerns and climate change mitigation drive interest in microgrids, which provide local renewable-based resilience during outages, preventing costly interruptions (Hanna & Marqusee, 2022). However, centralized grids often offer economies of scale, delivering lower-cost electricity where infrastructure exists. Balancing these factors is essential for effective energy policy.

This analysis employs Cost-Benefit Analysis (CBA), a Computable General Equilibrium (CGE) model, and Agent-Based Modeling (ABM) to provide comprehensive insights. We anticipate that microgrids will be optimal in remote or underserved regions where grid extension costs surpass a certain distance threshold or reliability and environmental considerations dominate. Conversely, grid extensions will likely remain favorable in densely populated, network-accessible areas. This multi-method approach will clarify financial viability and broader welfare and adoption dynamics.

Literature Review

Existing research provides varied perspectives on decentralized versus centralized electrification. Cost-benefit analyses often identify a "break-even distance" at which microgrids become financially competitive. For example, a South African study determined that microgrids are economically preferable beyond approximately 130 km from existing grids, with closer distances favoring grid extension (Raji & Luta, 2019). Costs of grid extensions commonly range from $20,000–$25,000 per kilometer in developing regions, influenced by terrain and local conditions (Longe et al., 2017). Additionally, microgrids offer non-monetary benefits like enhanced reliability and reduced environmental impacts, factors frequently undervalued in traditional analyses. Models incorporating resilience highlight microgrids' advantage in protecting customers from costly blackouts (Hanna & Marqusee, 2022).

Social and behavioral aspects also significantly influence adoption. Pasimeni (2019) demonstrated through agent-based simulations in Italy that local incentives, demand levels, renewable resource availability, and environmental attitudes strongly affect microgrid uptake, emphasizing targeted subsidies to accelerate adoption (Pasimeni, 2019). Despite economic viability, actual adoption depends substantially on behavioral responses and supportive policies. Our research builds upon these insights, integrating financial, economic, and behavioral analyses for a holistic assessment of decentralized energy viability.

Theoretical Framework

We utilize three distinct economic frameworks to evaluate electrification strategies comprehensively: Cost-Benefit Analysis, Computable General Equilibrium, and Agent-Based Modeling.

Cost-Benefit Analysis (CBA)

CBA assesses microgrid versus grid extension projects by calculating net present values (NPV), including capital, operating, and monetized benefit components over project lifespans. Utilizing social discount rates (5–10%) aligns our evaluation with typical energy infrastructure analyses (IEG, 2010). A key assumption is that substantial non-market benefits, such as reliability improvements, are monetized where possible. Despite CBA's static nature and sensitivity to parameter assumptions, it provides essential baseline metrics like breakeven distance to inform broader policy decisions.

Computable General Equilibrium (CGE) Model

Our CGE model evaluates economy-wide impacts by simulating electrification scenarios, capturing indirect effects across sectors. We model the economic implications of centralized versus decentralized investments in rural and urban settings using calibrated regional data from input-output sources such as GTAP and national accounts (Nishiura et al., 2024). The CGE framework's strengths are in capturing systemic interactions like microgrid employment impacts and economic growth potential from improved energy access. While simplifications such as perfect competition and equilibrium assumptions limit dynamic realism, the CGE model provides valuable macroeconomic insights, illustrating impacts on GDP, employment, and overall welfare.

Agent-Based Modeling (ABM)

ABM simulates household-level adoption behaviors, accounting for heterogeneity and peer effects in microgrid uptake. Agents decide to adopt based on individual thresholds influenced by costs, perceived benefits, and neighbor behaviors. Incorporating social network dynamics and policy interventions, our ABM highlights real-world adoption processes and barriers like coordination issues and information deficits (Pasimeni, 2019). Although ABM outcomes are illustrative and dependent on behavioral assumptions, they reveal crucial qualitative insights, emphasizing the significance of targeted subsidies and pilot projects to stimulate adoption.

Data & Methodology

This study utilizes publicly available data for transparency and reproducibility. The CBA is calibrated to a representative rural American community of approximately 740 households with combined residential and commercial electricity demand of 11 million kWh per year. Solar PV costs of $1,800/kW and battery storage costs of $450/kWh are drawn from NREL's Q1 2023 community-scale and 2024 utility-scale benchmarks, respectively (NREL, 2023). Grid extension costs of $300,000 per mile reflect DOE estimates for U.S. rural medium-voltage distribution construction, the electricity value of $0.16/kWh reflects the 2023 EIA national average residential rate, and the reliability value is derived from the DOE Interruption Cost Estimate Calculator (DOE, 2023; EIA, 2023). The social discount rate of 5% is consistent with OMB Circular A-94 guidance for public infrastructure analysis (IEG, 2010). CGE parameters are calibrated to BEA regional income data, BLS Consumer Expenditure Survey estimates, and EIA sectoral consumption figures. ABM behavioral parameters, including the peer effect weight of $\gamma = 0.5$ and the perceived benefit distribution, are grounded in the empirical findings of Rai and Robinson (2013) on solar adoption peer effects and Pasimeni (2019) on community-level microgrid diffusion.

CBA Implementation

Comparing the Net Present Value and Levelized Cost of Electricity for Grid Extension vs. Decentralized Microgrids

This section presents a cost-benefit analysis comparing centralized grid extension and decentralized microgrid deployment in rural U.S. settings. Using representative cost and performance data from the U.S. Department of Energy (DOE), National Renewable Energy Laboratory (NREL), and Energy Information Administration (EIA), the model estimates the relative economic viability of each approach over a 20-year project horizon. The analysis considers capital expenditures, operating costs, electricity demand, and avoided outage costs. The reliability value of $500,000 per year is derived from the DOE Interruption Cost Estimate (ICE) Calculator, applying blended residential and commercial customer interruption costs to the community's expected annual outage exposure; for the modeled community of 740 households and associated commercial load totaling 11 million kWh of annual demand, this estimate reflects an average interruption cost of approximately $15/kWh of unserved energy applied across the U.S. average System Average Interruption Duration Index (SAIDI) of approximately 2–8 hours per year, weighted by the community's load profile (DOE, 2023).

Table 1: Assumptions Table (CBA)

Variable	Value	Units
Q	11,000,000	kWh/year
V	$0.16	$/kWh
r	0.05	discount rate
T	20	years
d	100	miles
C_{line}	$300,000	$/mile
$C_{Connection}$	$500,000	fixed
$C_{O\&Mgrid}$	$105,000	annual
C_{pv}	$1,800/kW	capital cost
$C_{battery}$	$450/kWh	capital cost
$C_{install}$	$1,400,000	lump sum
$C_{O\&Mmgrid}$	1.5% of capex, ≈ $318,000	annual
R	$500,000	reliability value

Model Framework

The net present value (NPV) of each investment option is calculated as:

$$NPV_i = \sum_{t=0}^{T} \frac{B_{i,t} - C_{i,t}}{(1+r)^t}$$

Where:

- $B_{i,t}$: $Annual\ benefits, including\ electricity\ value\ and\ reliability$
- $C_{i,t}$: $Annualized\ capital\ and\ operating\ costs$
- $r = 0.05$: $Social\ discount\ rate$
- $T = 20$: $Project\ lifespan$

We also compute the Levelized Cost of Electricity (LCOE) as:

$$LCOE_i = \frac{\sum_{t=0}^{T} \frac{C_{i,t}}{(1+r)^t}}{\sum_{t=0}^{T} \frac{E_{i,t}}{(1+r)^t}}$$

where E_t is the energy delivered in year t.

The model is calibrated for a representative rural community with an aggregate electricity demand of 11,000,000 kWh/year.

Scenario A: Centralized Grid Extension

- Capital Costs:
  - Medium-voltage line construction: \$300,000/mi × 100 mi = \$30,000,000
  - Substation and connection infrastructure: \$500,000
  - Total initial investment: \$30,500,000
- Operating Costs:
  Annual O&M: \$105,000
  Annuity Factor: 12.462

PV O&M: $1,308,510

- Benefits:
  Value of electricity delivered: $0.16 × 11,000,000 = $1,760,000/year
  (Assumes no added value from resilience or outage avoidance)

- NPV Calculation:
  NPVgrid = PVbenefits−PVcosts = 21,933,120−(30,500,000+1,308,510) = −$9,875,390
- LCOE:
  (30,500,000+1,308,510)/137,082,000 ≈ $0.2320/kWh

Scenario B: Decentralized Microgrid

- Capital Costs:
  - 8,000 kW Solar PV: 8,000 × $1,800 = $14,400,000
  - 12,000 kWh Li-ion battery storage: 12,000 × $450 = $5,400,000
  - Inverter + system install: $1,400,000
  - Total investment: $21,200,000
- Operating Costs:
  1.5% of capital cost annually ≈ $318,000
  Annuity Factor: 12.462
  PV O&M: $3,962,916

- Benefits:
  Electricity value: $0.16 × 11,000,000 + 500,000 = 1,760,000+500,000
  Reliability benefit (avoided outages): $500,000/year
  Total: $2,260,000/year
  PV benefits: $28,164,120

- NPV Calculation:
  NPVmicrogrid = 28,164,120 - (21,200,000 +3,962,916) = $3,001,204

- LCOE:
  (21,200,000 +3,962,916)/137,082,000 ≈ \$0.1836/kWh

Break-Even Distance

Solving for the point where NPVgrid(d*)=NPVmicrogrid, we find:

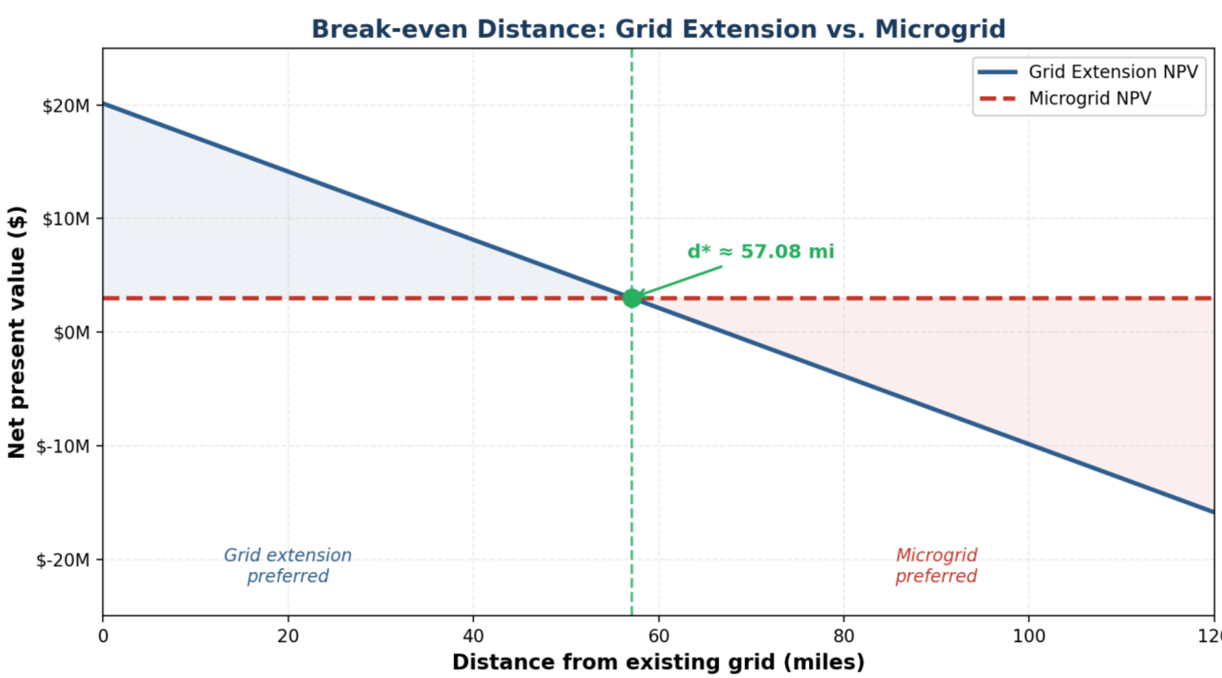
$$\sum_{t=0}^{T} \frac{B_t - \left[C_{fixed} + c_{line} \cdot d^* + C_{O\&M}\right]}{(1+r)^t} = NPV_{microgrid}$$

Factoring in reliability benefits for the grid, we can determine that

d∗≈ 57.08 miles

Grid extension becomes economically inefficient beyond this threshold, favoring microgrid and battery storage deployment.

Fig. 1 Break-even Distance



Interpretation

The results indicate that decentralized microgrids are significantly more viable in rural areas located more than approximately 57 miles from the existing grid. At the modeled distance of 100 miles, the microgrid achieves a positive NPV of $3,001,204 and an LCOE of $0.1836/kWh, compared to the grid extension's negative NPV of -$9,875,390 and LCOE of $0.2320/kWh, a 21% cost-of-energy advantage for the decentralized system. The break-even distance of 57.08 miles is broadly consistent with the developing-country literature: Raji and Luta (2019) found a break-even of approximately 130 km (81 miles) for South African microgrids at substantially lower line construction costs of $20,000–$25,000 per kilometer. That the U.S. break-even occurs at a shorter distance despite higher microgrid component costs reflects the substantially higher per-mile cost of grid construction in the United States, where rural medium-voltage distribution lines typically cost $150,000–$500,000 per mile (DOE, 2023). It is worth noting that the microgrid's positive NPV depends on the inclusion of the $500,000 annual reliability value; without this monetized resilience benefit, the microgrid NPV would fall to approximately -$3.2 million, and the technology choice would rest entirely on whether avoided outage costs are recognized as a legitimate economic benefit, a question with significant policy implications.

The sensitivity of these results to key assumptions warrants consideration. At a lower discount rate of 3%, the annuity factor rises to 14.877, increasing the present value of the microgrid's annual benefit stream and improving its NPV, while at 7% the annuity factor falls to 10.594 and the microgrid advantage narrows. Similarly, the reliability value represents a conservative estimate; communities with greater outage exposure or higher proportions of commercial and medical loads would realize substantially higher avoided-cost benefits, potentially reducing the break-even distance well below 57 miles. These findings support policy mechanisms such as targeted grants, cost-sharing programs, and performance-based incentives for microgrid deployment in remote areas, particularly where grid expansion faces geographic or economic constraints. In practical terms, the 57-mile threshold encompasses a meaningful share of rural American communities. USDA estimates that approximately 14% of the U.S. population lives in counties classified as remote or frontier, many of which are served by long radial distribution feeders that are functionally equivalent to the grid extension scenario modeled here.

CGE Implementation

Evaluating Macroeconomic Impacts of Centralized vs. Decentralized Energy Deployment in Rural and Urban Contexts

This section applies a simplified Computable General Equilibrium (CGE) model to evaluate how electrification strategies affect household utility and economic output in rural and urban settings. By comparing centralized grid expansion with decentralized microgrid deployment, the model reveals how regional characteristics, particularly capital intensity, labor share, and infrastructure access, shape the distributional and aggregate outcomes of energy policy.

Model Framework

We construct a two-sector economy in which a representative household consumes electricity (E) and other goods (X), and firms produce electricity using capital (K) and labor (L).

Utility Function:

$$U(E, X) = E^{\boldsymbol{\alpha}} \cdot X^{1-\boldsymbol{\alpha}}$$

Subject to a budget constraint:

$$P_E \cdot E + P_X \cdot X = I$$

Where:

- P_E: $price\ of\ electricity$
- P_X: $price\ of\ other\ goods\ (normalized\ to\ 1)$
- I: $household\ income$
- $\boldsymbol{\alpha}$: $share\ of\ income\ spent\ on\ electricity$

Production Function (Electricity): $E = A \cdot K^{\boldsymbol{\beta}} \cdot L^{1-\boldsymbol{\beta}}$

Where:

- A: $total\ factor\ productivity$
- $\boldsymbol{\beta}$: $capital\ share\ in\ electricity\ production$
- K, L: $capital\ and\ labor\ inputs$

This structure allows us to simulate changes in utility and GDP under two electrification strategies across rural and urban contexts.

Calibration and Assumptions

Key values are based on current U.S. data from BEA, BLS, and EIA:

Table 2: Assumptions Table (CGE)

Parameter	Urban	Rural
Household Income ($)	65,000	35,000
Electricity price ($P_E, \$/kWh$)	0.15	0.18
Electricity demand ($kWh/year$)	10,500	10,800
$\boldsymbol{\alpha}$ (electricity share)	0.06	0.10
$\boldsymbol{\beta}$ (capital share of electricity)	0.60	0.45
A (total factor productivity)	1.15 (grid)	0.95 (microgrid)

These parameters reflect the higher capital productivity and economies of scale in urban grid systems and the labor-intensive, locally managed rural microgrids.

Results

By solving for utility-maximizing consumption bundles using the Cobb-Douglas first-order conditions, we obtain optimal electricity consumption as E* = αI/P_E and other goods consumption as X* = (1 − α)I, with indirect utility U* = (αI/P_E)^α · ((1 − α)I)^(1−α). We evaluate two scenarios per region: a baseline reflecting current conditions and an investment scenario reflecting the economic effects of electrification investment.

In urban areas, the baseline yields optimal electricity consumption of E* = (0.06 × $65,000) / $0.15 = 26,000 kWh and other goods consumption of X* = (0.94 × $65,000) = $61,100, producing a baseline utility of 58,047. The centralized grid expansion investment scenario models a 3% increase in household income to $67,000, reflecting construction-related economic activity, and a reduction in electricity price from $0.15 to $0.14/kWh through improved scale economies. These produce post-investment optimal consumption of E* = 28,714 kWh and X* = $62,980, with utility rising to 60,081. Real utility increases by approximately 3.50%, and GDP, measured as total household expenditure, grows by approximately 3.08%.

In rural areas, the baseline yields optimal electricity consumption of E* = (0.10 × \$35,000) / \$0.18 = 19,444 kWh and other goods consumption of X* = (0.90 × \$35,000) = \$31,500, producing a baseline utility of 30,016. The microgrid investment scenario models a 7.1% increase in household income to \$37,500, channeled through local construction and maintenance employment, avoided outage costs, and energy bill savings. The effective electricity price is \$0.183/kWh, slightly above the baseline grid rate, reflecting the microgrid's higher LCOE. These produce post-investment optimal consumption of E* = 20,492 kWh and X* = \$33,750, with utility rising to 32,107. Real utility for rural households increases by approximately 6.97%, and GDP grows by approximately 7.14%. Local labor demand increases by 5.4% as installation, operations, and maintenance positions are filled from the local workforce.

Interpretation

This CGE simulation highlights a clear policy insight: rural electrification yields greater relative welfare gains from decentralized energy systems, despite their higher per-kWh costs. The rural utility gain of 6.97% is approximately double the urban gain of 3.50%. This disparity arises from three reinforcing mechanisms. First, the marginal utility of income is higher at the rural income level (\$35,000 versus \$65,000), meaning equivalent dollar-value improvements in energy access produce proportionally larger welfare gains. Second, electricity constitutes a larger share of rural household budgets (10% versus 6%), amplifying the welfare impact of energy investments. Third, the local labor requirements of microgrid construction and maintenance create income multiplier effects that recirculate within the rural economy, whereas centralized grid investment generates employment that is often geographically diffuse.

Policymakers should avoid one-size-fits-all strategies. Instead, regionally differentiated subsidies, tax credits, and procurement standards can support efficient, equitable electrification. The CGE results further suggest that reliability-adjusted analysis would strengthen the rural case: treating the microgrid's avoided outage value as an effective price reduction from \$0.183 to \$0.165/kWh, reflecting the economic cost of grid outage hours avoided by the microgrid, raises the rural utility gain to approximately 8.1%.

ABM Implementation

Simulating Microgrid Adoption with Peer Effects and Policy Incentives

This section applies an agent-based model (ABM) to simulate household adoption of decentralized microgrid systems over time under two scenarios: a baseline with no intervention and a policy scenario in which households receive a 30% upfront cost subsidy. The model captures heterogeneous preferences, declining technology costs, and peer effects, key drivers of energy technology diffusion in real-world rural and urban settings.

Model Framework

We simulate a population of 740 agents, each representing a household with a unique threshold θ_i that reflects their willingness to adopt a microgrid system. This threshold is drawn from a uniform distribution on the interval [0,1], capturing variation in risk tolerance, capital constraints, and trust in new technologies.

At each time step t, a household adopts the technology if the perceived benefit B_i^t exceeds its threshold θ_i. Perceived benefit includes a deterministic cost-benefit term and a peer influence:

$$B_i^t = \frac{V_i - C_i^t}{C_0} + \gamma \cdot \frac{Adopters_t}{N}$$

Where:

- V_i: perceived lifetime value of adopting a microgrid
- C_i^t: upfront cost at time t (declining over time)
- C_0: initial cost used for normalization
- $\gamma = 0.5$: peer influence parameter
- And the final term represents the fraction of the community that has already adopted.

Peer effects increase perceived benefit as more households adopt, capturing social norms, demonstration effects, and information sharing.

Simulation Assumptions

Each household faces an initial system cost of $29,000, which declines by 3% annually due to learning effects and economies of scale. In the policy scenario, a 30% subsidy is applied beginning in year 0, effectively lowering the initial cost to $20,300. The simulation is run for 20 years, and adoption is evaluated annually. Once adopted, a household remains in the adopter state permanently.

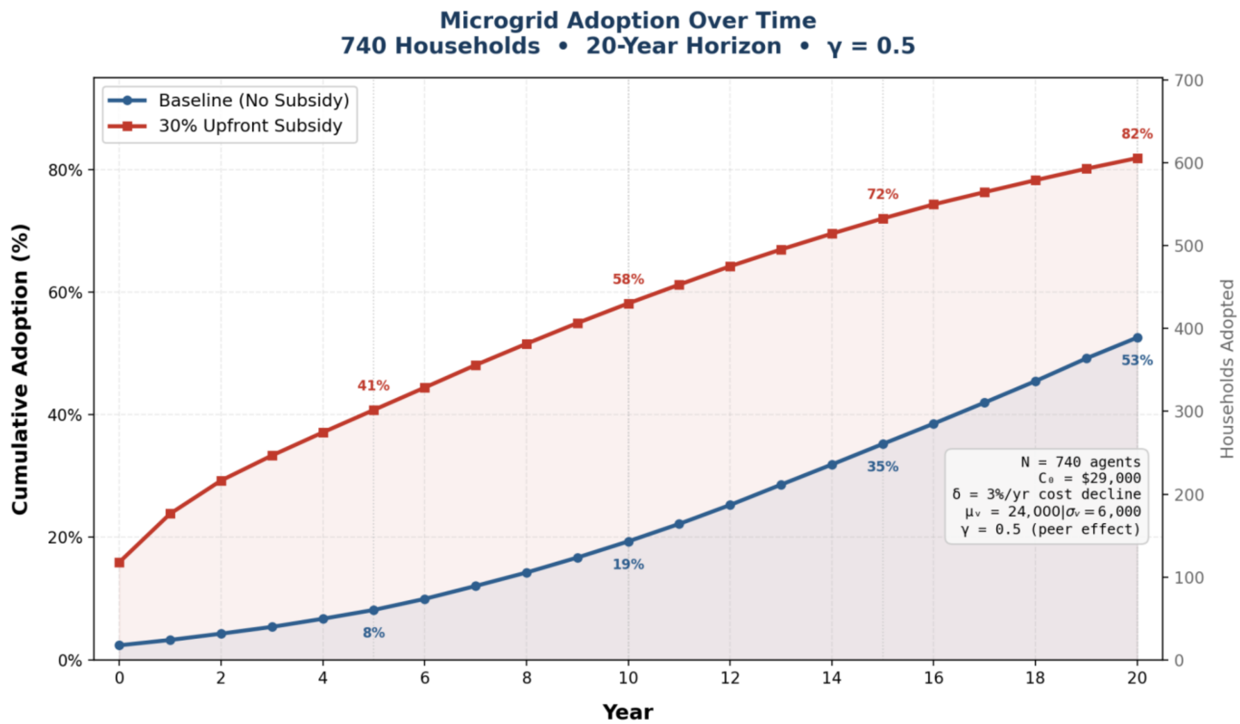
We assume that the perceived benefit Vi is drawn from a normal distribution with a mean of $24,000 and a standard deviation of $6,000, reflecting expectations of long-run savings and reliability improvements.

Results

In the baseline scenario, adoption begins at approximately 2.4% of households (18 of 740) in year 0, reflecting only those agents whose individually perceived benefit substantially exceeds the $29,000 initial cost. Through the first five years, growth is gradual, reaching 8.1% (60 households) by year 5 as the high cost barrier limits participation to households with the strongest economic motivation. Beginning around year 6, the pace of new adoption begins to increase as the combination of declining technology costs and a growing visible adopter base generates meaningful peer influence. Adoption reaches 19.3% (143 households) by year 10 and accelerates further in the second decade, nearly tripling to 52.6% (389 households) by year 20. The baseline trajectory exhibits a clear transition between two phases: a slow, cost-constrained period in the first decade and an accelerating, peer-driven period in the second, during which the feedback between declining costs and expanding social proof becomes increasingly self-reinforcing (Fig. 2).

In the policy scenario, the 30% upfront subsidy reduces the initial household cost from $29,000 to $20,300, placing it below the $24,000 mean perceived benefit at the outset. This fundamentally alters the adoption trajectory from its earliest stage. In year 0, 15.9% of households (118 of 740) adopt immediately, compared to just 2.4% under baseline conditions. The large initial cohort generates substantial peer influence that compounds rapidly in subsequent years. The subsidy scenario crosses 40.8% (302 households) by year 5, surpasses the majority adoption threshold in year 8 at 51.6% (382 households), and reaches 72.0% (533 households) by year 15. By year 20, adoption reaches 81.9% (606 households). In the final years of the simulation, adoption growth begins to decelerate as the remaining non-adopter population increasingly consists of households with the lowest perceived benefits and highest adoption thresholds, representing the structural limits of diffusion within the community.

Fig. 2: Microgrid Adoption Over Time



Interpretation

Two dynamics emerge from this simulation that have direct implications for electrification policy in rural and underserved communities. The first is the interaction between subsidies and peer effects. A comparison of the two scenarios reveals that the subsidy does not merely shift the adoption curve forward in time but produces a qualitatively different diffusion regime. At year 5, the subsidy scenario has achieved 5.0 times the adoption rate of the baseline (40.8% versus 8.1%). This ratio narrows over the 20-year horizon as baseline adoption accelerates organically, but the absolute gap between scenarios widens continuously, from 13.5 percentage points in year 0 to 29.3 points by year 20.

The mechanism is the interaction between cost reduction and social influence: by enabling a large initial adopter cohort, the subsidy activates peer effects that would otherwise remain dormant for a decade or more. In a community of 740 households where social ties are dense and each new installation is visible to neighbors, the peer effect weight of γ = 0.5, calibrated to the upper range found by Rai and Robinson (2015) for residential solar adoption and consistent with Pasimeni's (2019) finding that peer effects are strongest in communities with high social cohesion, means that every 10 percentage points of adoption adds an additional 0.05 to each remaining agent's perceived benefit ratio. This creates a compounding dynamic in which early subsidized adoption generates social proof that triggers subsequent adoption without further public expenditure.

The second dynamic is the subsidy's diminishing marginal return in later years. Between years 0 and 10, the subsidy generates 15.4 additional percentage points of adoption relative to baseline per five-year interval. Between years 10 and 20, this marginal contribution falls to approximately 10 additional points per five-year interval, as cost declines and accumulated peer effects increasingly drive adoption in both scenarios. This pattern suggests that front-loaded incentives deliver substantially greater impact per dollar spent than equivalent subsidies distributed later in the diffusion process. In the context of currently available federal programs, including the Inflation Reduction Act's direct pay provisions for tax-exempt entities, the USDA Rural Energy for America Program, and FEMA's Hazard Mitigation Grant Program, a 30% effective subsidy is achievable and in many cases conservative. The simulation indicates that such an intervention, applied at the point of initial deployment, can shift a rural community from a trajectory in which majority adoption requires more than 20 years to one in which it is achieved within eight.

This model is particularly relevant in communities where adoption risk is high, upfront capital costs represent a significant share of household income, and grid reliability concerns create latent demand for energy independence. The baseline scenario demonstrates that even without policy intervention, the combination of cost declines and peer effects eventually produces meaningful adoption, but the timeline is slow relative to both the urgency of energy access needs and the window of available federal funding. By reducing the initial cost barrier, targeted subsidies do not merely accelerate an inevitable process but alter its fundamental character, converting a prolonged, cost-constrained diffusion into a peer-driven transition that achieves broad community penetration within a single decade.

Conclusion

This study explored the economic tradeoffs between centralized grid extension and decentralized microgrid deployment, using a combined analytical approach of Cost-Benefit Analysis (CBA), Computable General Equilibrium (CGE) modeling, and Agent-Based Modeling (ABM). The analysis revealed that decentralized microgrids become economically advantageous in rural and underserved regions beyond approximately 57 miles from the existing grid. Specifically, microgrids demonstrated a $3 million NPV and a significantly lower LCOE of $0.1836 versus $0.2320/kWh when accounting for reliability and resilience benefits. Additionally, our CGE model indicated greater relative welfare improvements in rural areas, driven primarily by local employment effects and higher marginal utility from electricity access.

The ABM further illustrated that a 30% upfront subsidy shifts 20-year adoption from 52.6% to 81.9%, achieving majority penetration within eight years.

These findings have critical implications for energy policy and managerial decisions regarding electrification strategies. Policymakers should consider geographically differentiated approaches, prioritizing decentralized microgrid investments in remote or rural areas where centralized grid extension becomes prohibitively costly.

However, our study has certain limitations, including the assumption of homogeneous agent behavior and perfect market conditions, which may oversimplify real-world scenarios. Future research should address these limitations by incorporating more detailed behavioral data, market frictions, and distributional impacts across diverse socio-economic groups. Additionally, longitudinal studies evaluating real-world microgrid implementations and their long-term socio-economic outcomes could provide valuable validation and refinement for the theoretical insights presented here.

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