Competitive Distribution Expansion With Reactive Power-Aware DERs Under Deep Electrification

Mohammad Amin Mirjalili
Systems Design Engineering
University of Waterloo
Waterloo, Canada
smamirja@uwaterloo.ca

Jessie Ma
Systems Design Engineering
School of Environment, Enterprise, and Development
University of Waterloo
Waterloo, Canada
jessie.ma@uwaterloo.ca

***Abstract*—This paper presents a techno-economic framework for distribution network expansion planning (DNEP) under deep electrification. A competitive bidding structure is formulated in which distributed energy resources (DERs) and network reinforcements compete as investment options over a multi-decade horizon. Unlike existing approaches, the model explicitly incorporates DER reactive-power support by embedding a loss-cost term in the objective, enabling coordinated active and reactive dispatch. The framework is applied to the modified IEEE 123-node feeder and benchmarked against a recent reference model that excludes VAR capability and substation expansion. Results show that the proposed formulation reduces reliance on shunt capacitors, defers traditional reinforcements at higher growth rates, and achieves lower combined investment and maintenance costs, despite the additional objective term. These findings highlight the value of treating DERs as full active–reactive participants in expansion planning, supporting more efficient pathways toward deep electrification and net-zero targets.**

***Index Terms*-- Deep electrification, Distributed energy resources, Distribution network expansion planning, Reactive power compensation**

I. INTRODUCTION

Deep electrification is a central pathway for achieving mid-century net-zero objectives, shifting end-use energy across transportation, buildings, and industry toward clean electricity [1]. As these electrified demands scale, the distribution grid becomes the primary interface for new loads and small, inverter-dominated resources [2]; consequently, system architecture and control must evolve to coordinate heterogeneous, grid-edge assets at scale while preserving reliability [3]. Prior work motivates this shift as both a decarbonization driver and an information-and-control challenge and shows that aggregations of DERs can be modeled and coordinated to provide system-level flexibility [4].

Realizing this vision requires treating DERs as dispatchable elements of the distribution system that deliver not only active power but also essential services [5]. Inverter-interfaced resources can supply and absorb reactive power, enabling feeder-level voltage regulation and loss reduction when coordinated through local, decentralized, or distributed controls—establishing DERs as viable providers of reactive-power support at scale [6], [7].

This paper develops a techno-economic framework for distribution expansion based on competitive bidding and multisource coordination, modeling DERs as dispatchable providers of active power and reactive support.

A. Contributions of This Paper

1. *Extended Planning Horizon:* A multi decade expansion framework that exceeds the common five to ten year scope.
2. *Scale of Demand Growth:* Deep electrification cases for electric vehicles, heating, and AI and data centers, with growth rates above those in prior work.
3. *Full DER Integration:* All DER types are modeled as dispatchable assets that compete with network reinforcements across the planning horizon.
4. *Competitive Approach:* A market-based scheme where DERs, storage, and network reinforcements compete to deliver least cost investment.
5. *Reactive Power Aware Planning:* Integration of reactive power compensation from all generation assets by adding a loss cost term to the objective function, which internalizes the value of VAR support and enables coordinated active and reactive dispatch that improves voltage profiles and reduces feeder losses.

II. LITERATURE REVIEW

Traditional DNEP treats feeders as passive assets and optimizes reinforcements over short horizons, typically with deterministic or reliability-oriented models [8]; this stream focuses on cost, losses, or reliability [9]. Subsequent work partially integrates flexibility—e.g., storage and demand response or specific DER types—but still models DERs mostly as static elements and leaves scheduling outside the expansion model [10].

A few studies introduce local market mechanisms or bi/tri-level structures, yet they generally adopt short/medium horizons and do not reflect accelerated growth from deep electrification [11], [12]. Reactive power compensation has been studied at the device and feeder level, for example DG plus reactive power sources, renewable DG with explicit reactive capability limits, and distribution static synchronous compensator placement for loss and voltage performance [13]. These works demonstrate technical feasibility of VAR support but are not embedded in a competitive expansion framework and do not address multi-decade horizons or accelerated demand growth.

Taken together, the literature remains fragmented and falls short in several respects, including the absence of a competitive market-based setting where DERs contend with network reinforcements, partial modeling of DERs without dispatchable reactive power support or loss cost monetization, short to medium planning horizons, and limited treatment of deep electrification growth. Table I benchmarks representative studies against these dimensions and motivates the contributions advanced in this paper.

979-8-3315-8138-1

TABLE I. COMPARISON OF EXISTING STUDIES WITH THE PROPOSED MODEL

Ref	Model			Case Study	
	Reactive power compensation	Full DER integration	Market -based	Deep electrification	Planning horizon
[10]	No	No	No	No	Short-term
[8]	No	No	No	No	Medium-term
[9]	Yes	No	No	No	Short-term
[11]	No	Yes	Yes	No	Medium-term
[12]	No	Yes	Yes	No	Short-term
[13]	Yes	No	No	No	Short-term
[4]	No	Yes	Yes	Yes	Long-term
Proposed Model	Yes	Yes	Yes	Yes	Long-term

III. METHODOLOGY

A DNEP formulation is presented in which heterogeneous supply bids—flexible DERs, conventional and intermittent generation, storage, and network reinforcements—are jointly considered over long-term horizons consistent with accelerated demand growth toward net-zero targets; DER reactive-power compensation is incorporated through explicit power-loss cost terms.

Let $t \in \mathcal{T}$ denote the planning year; $n, i, j \in \mathcal{N}$ the nodes; $s \in \mathcal{S}$ the supplier; and a an asset (bid). Asset sets are $\mathcal{G}_{CG}$ (conventional generation), $\mathcal{G}_{DG}$ (intermittent generation), $\mathcal{G}_{ESS}$ (energy storage system), $\mathcal{G}_{SC}$ (shunt capacitors), $\mathcal{G}_{VR}$ (voltage regulators), $\mathcal{G}_{F}$ (feeders), $\mathcal{G}_{TR}$ (transformers), and $\mathcal{G}_{S}$ (substations). Unit investment and maintenance costs are $C^{I}_{s,t,a}$ and $C^{M}_{s,t,a}$ (units \$/kW, \$/kWh, \$/kVAr, or \$ as appropriate); the annual loss-cost is C^{L}_{t}; IR and DR are the inflation and discount rates. Technical data include capacities $Ca^{(\cdot)}_{s,t,a}$ (kW/kWh/kVAr), peak demands $P^{L}_{t,j}$, $Q^{L}_{t,j}$, normalized solar irradiance SI_t, wind speed WS_t, voltage bounds V_{min}, V_{max}, minimum power factor PF_{min}, wind speeds V_{in}, V_{rated}, V_{out}, feeder/transformer limits $P^{IF}_{limit}, Q^{IF}_{limit}$ and $P^{ITR}_{limit}, Q^{ITR}_{limit}$, substation capacity S^2_{max}, annual O&M escalation rate $\lambda^{(\cdot)}$, reference voltage v_{ref}, regulator step and bandwidth Γ_a, β_a and tolerance ϵ. Investment selections are $x^{(\cdot)}_{(\cdot)}$; utilization/availability variables are $y^{(\cdot)}_{(\cdot)}$; existing assets are indicated by $l^{\mathrm{F}}_{i,j,t}, l^{\mathrm{TR}}_{i,j,t}$. Operational variables include branch flows $P^{flow}_{t,i,j}, Q^{flow}_{t,i,j}$, nodal voltage v^{j}_{t}, feeder parameters $r^{F}_{i,j,t}, x^{F}_{i,j,t}$, current-magnitude squared $\ell_{i,j,t}$, substation exchanges P^{PE}_{tj}, Q^{PE}_{tj}, conventional generator outputs $P^{CG}_{t,s,a,j}, Q^{CG}_{t,s,a,j}$, intermittent generator outputs $P^{DG}_{t,s,a,j}, Q^{CGDG}_{t,s,a,j}$ and capacitor VARs $Q^{SC}_{t,s,a,j}$. Storage variables are $\mathrm{SoC}_{s,t,a,\mathrm{n}}$ (with $SoC^{Initial}_{s,t,a,n}$) and charge/discharge powers $P^{cESS}_{t,s,a,n}, P^{dESS}_{t,s,a,n}$. Voltage-regulator auxiliaries are $v'^{j}_{t}, v''^{j}_{t}, w^{j}_{t}$, drop factor $f^{VR}_{(i,j),s,t,a}$, binary tap selector $B^{VR}_{(i,j),s,t,a}$, and discrete tap position $\psi^{VR}_{(i,j),s,t,a}$.

A. Mathematical Formulation

1) Objective function

$$\text{Min } Totex = \sum_{t\in\mathcal{T}} \frac{\left(C^{I}_{t} + C^{M}_{t} + \frac{C^{L}_{t}}{2}\right)}{(1+DR)^{t-1}}(1+IR)^{t-1} \tag{1}$$

The objective function (1) minimizes total expenditure (Totex) over time by minimizing investment costs (C^{I}_{t}), maintenance costs (C^{M}_{t}), and the loss-cost term ($0.5 \cdot C^{L}_{t}$) (half-weighted to avoid double counting). Future costs are first escalated using the inflation rate and then discounted to present value using the discount rate.

$$\begin{aligned}
C^{I}_{t} = & \sum_{n,i,j\in\mathcal{N}} \sum_{s\in\mathcal{S}} \Big(\sum_{a\in\mathcal{G}_{CG}} C^{ICG}_{s,t,a} \cdot Ca^{CG}_{s,t,a} \cdot x^{ICG}_{n,s,t,a} \\
& + \sum_{a\in\mathcal{G}_{S}} C^{IS}_{s,t,a} \cdot Ca^{S}_{s,t,a} \cdot x^{IS}_{n,s,t,a} + \frac{1}{2}\sum_{a\in\mathcal{G}_{TR}} C^{ITr}_{s,t,a} \cdot x^{ITR}_{(i,j),s,t,a}\Big) \\
& + \sum_{a\in\mathcal{G}_{ESS}} \left(C^{IEESS}_{s,t,a} \cdot Ca^{EESS}_{s,t,a} + C^{IPESS}_{s,t,a} \cdot Ca^{PESS}_{s,t,a}\right) \cdot x^{IESS}_{n,s,t,a} \\
& + \sum_{a\in\mathcal{G}_{VR}} C^{IVR}_{s,t,a} \cdot x^{IVR}_{(i,j),s,t,a} + \sum_{a\in\mathcal{G}_{SC}} C^{ISC}_{s,t,a} \cdot Ca^{SC}_{s,t,a} \cdot x^{ISC}_{n,s,t,a} \\
& + \sum_{a\in\mathcal{G}_{DG}} C^{IDG}_{s,t,a} \cdot Ca^{DG}_{s,t,a} \cdot x^{IDG}_{n,s,t,a} + \frac{1}{2}\sum_{a\in\mathcal{G}_{F}} C^{IF}_{s,t,a} \cdot x^{IF}_{(i,j),s,t,a}
\end{aligned} \tag{2}$$

$$\begin{aligned}
C^{M}_{t} = & \sum_{n,i,j\in\mathcal{N}} \sum_{s\in\mathcal{S}} \Big(\sum_{a\in\mathcal{G}_{CG}} C^{MCG}_{s,t,a} \cdot Ca^{CG}_{s,t,a} \cdot y^{CG}_{n,s,t,a} \cdot \phi^{CG}_{t} \\
& + \sum_{a\in\mathcal{G}_{S}} C^{MS}_{s,t,a} \cdot Ca^{S}_{s,t,a} \cdot y^{CS}_{s,t,a} \cdot \phi^{S}_{t} + \sum_{a\in\mathcal{G}_{ESS}} C^{MESS}_{s,t,a} \cdot Ca^{ESS}_{s,t,a} \cdot y^{ESS}_{n,s,t,a} \cdot \phi^{ESS}_{t} \\
& + \sum_{a\in\mathcal{G}_{SC}} C^{MSC}_{s,t,a} \cdot Ca^{SC}_{s,t,a} \cdot y^{SC}_{n,s,t,a} \cdot \phi^{SC}_{t} + \sum_{a\in\mathcal{G}_{VR}} C^{MVR}_{s,t,a} \cdot y^{VR}_{(i.j),s,t,a} \cdot \phi^{VR}_{t} \\
& + \sum_{a\in\mathcal{G}_{DG}} C^{MDG}_{s,t,a} \cdot Ca^{DG}_{s,t,a} \cdot y^{DG}_{n,s,t,a} \cdot \phi^{DG}_{t} \Big)
\end{aligned} \tag{3}$$

$$C^{L}_{t} = 8760 \cdot \sum_{i,j\in\mathcal{N}} r^{F}_{i,j,t} \cdot \ell_{i,j,t} \tag{4}$$

Equations (2)-(4) specify the cost terms of the DNEP. The investment cost in (2) covers conventional generation (CG), substations (S), distributed generation (DG, e.g., solar/wind), energy system storage (ESS; both power and energy), shunt capacitors (SC), voltage regulators (VR), feeders (F), and transformers (TR); each term is the product of a unit cost, the relevant decision variable, and, where applicable, a capacity component. The maintenance cost in (3) includes CG, DG, ESS, SC, and VR and is modeled as a capacity-based term with a linear aging factor, $\phi^{(\cdot)}_{t} = 1 + \lambda^{(\cdot)} \cdot age_{t,a}$, over the asset lifetime [4]. The loss cost in (4) monetizes network losses; the factor 8760 converts instantaneous power losses to annual energy (hours per year), aggregating losses across branches and periods [13].

2) Power balance constraints

$$\begin{aligned}
P^{flow}_{t,i,j} = & \sum_{\substack{m\in N\\ m\neq i}} P^{flow}_{t,j,m} + P^{L}_{t,j} - P^{PE}_{tj} - \sum_{a\in\mathcal{G}_{CG}\text{ in j}} P^{CG}_{t,s,a,j} \cdot y^{CG}_{t,s,a} \\
& - \sum_{a\in\mathcal{G}_{DG}\text{ in j}} P^{DG}_{t,s,a,j} \cdot y^{DG}_{t,s,a} + \sum_{a\in\mathcal{G}_{ESS}\text{ in j}} \left(P^{cESS}_{t,s,a,j} - P^{dESS}_{t,s,a,j}\right) \cdot y^{ESS}_{t,s,a}
\end{aligned} \tag{5}$$

$$\begin{aligned}
Q^{flow}_{t,i,j} = & \sum_{\substack{m\in N\\ m\neq i}} Q^{flow}_{t,j,m} + Q^{L}_{t,j} - Q^{PE}_{\mathrm{t,j}} - \sum_{a\in\mathcal{G}_{ESS}\text{ in j}} Q^{cESS}_{t,s,a,j} \cdot y^{ESS}_{t,s,a} \\
& - \sum_{a\in\mathcal{G}_{DG}\text{ in j}} Q^{DG}_{t,s,a,j} \cdot y^{DG}_{t,s,a} - \sum_{a\in\mathcal{G}_{CG}\text{ in j}} Q^{CG}_{t,s,a,j} \cdot y^{CG}_{t,s,a} \\
& - \sum_{a\in\mathcal{G}_{SC}\text{ in j}} Q^{SC}_{t,s,a,j} \cdot y^{SC}_{t,s,a}
\end{aligned} \tag{6}$$

$$v^{j}_{t} = \left(v^{i}_{t} - 2\left(r^{F}_{i,j,t} \cdot P^{ij}_{t} + x^{F}_{i,j,t} \cdot Q^{ij}_{t}\right)\right. \tag{7}$$

$$r^{F}_{i,j,t} = l^{\mathrm{F}}_{i,j,t} \cdot r^{IF}_{i,j} + \sum_{a\in\mathcal{G}_{F}} y^{F}_{i,j,s,t,a} \cdot r^{PF}_{i,j,a}$$

$$x^{F}_{i,j,t} = l^{\mathrm{F}}_{i,j,t} \cdot x^{IF}_{i,j} + \sum_{a\in\mathcal{G}_{F}} y^{F}_{i,j,s,t,a} \cdot x^{PF}_{i,j,a} \tag{8}$$

$$P_t^{ij^2} + Q_t^{ij^2} \le \ell_{i,j,t} \cdot v_{ref}^2 \tag{9}$$

$$P_{t,j}^{PE^2} + Q_{t,j}^{PE^2} \le S_{max}^2 \cdot x_t^S + Ca_{s,t,a}^{s}{}^2 \cdot y_{n,s,t,a}^{IS} \tag{10}$$

$$\frac{P_{t,j}^{PE}}{\sqrt{P_{t,j}^{PE^2} + Q_{t,j}^{PE^2}}} \ge PF_{min} \tag{11}$$

For voltage regulators:

$$v'^j_t = (v_t^i - 2(r_{i,j,t}^F \cdot P_t^{ij} + x_{i,j,t}^F \cdot Q_t^{ij}) \tag{12}$$

$$v''^j_t = \Delta drop_t^j + 1 \tag{13}$$

$$\Delta drop_t^j = f_{(i,j),s,t,a}^{VR} \cdot y_{(i,j),s,t,a}^{VR} \tag{14}$$

$$w_t^j = v'^j_t \cdot v''^j_t \tag{15}$$

$$v_t^j = w_t^j \tag{16}$$

$$B_{(i,j),s,t,a}^{VR}{}^2 \le f_{(i,j),s,t,a}^{VR} \tag{17}$$

$$\frac{\Gamma_a}{2 \cdot \beta_a} \cdot B_{(i,j),s,t,a}^{VR} - 0.5 + \epsilon \le \psi_{(i,j),s,t,a}^{VR} \tag{18}$$

$$\psi_{(i,j),s,t,a}^{VR} - 0.5 \le \frac{\Gamma_a}{2 \cdot \beta_a} \cdot B_{(i,j),s,t,a}^{VR} \tag{19}$$

3) Logic constraints

$$\begin{cases} y_{n,s,t,a} = x_{n,s,t,a} & \\ y_{n,s,t,a} = y_{n,s,t-1,a} & t < Life\ service\ [a] \\ 0 & t \ge Life\ service\ [a] \end{cases} \tag{20}$$

$$l_{i,j,t}^{\mathrm{F}} + \sum_{a \in \mathcal{G}_F} y_{i,j,s,t,a}^F = 1, \forall (a) \in \mathcal{G}_F \tag{21}$$

$$l_{i,j,t}^{\mathrm{TR}} + \sum_{a \in \mathcal{G}_{TR}} y_{i,j,s,t,a}^{TR} = 1, \forall (a) \in \mathcal{G}_{TR} \tag{22}$$

$$x_{i,j,t}^{\mathrm{S}} + \sum_{a \in \mathcal{G}_S} y_{n,s,t,a}^S = 1, \forall (a) \in \mathcal{G}_{TR} \tag{23}$$

Equations (5)-(6) enforce active and reactive power balance at each node. Active power balance (5) accounts for CG, DG, ESS injections, imports/exports, and feeder flows. Reactive power balance (6) includes compensating devices such as SC, reactive generation from DERs, and network flows. Equations (7)-(9) represent branch power flow and voltage relations under a linearized distribution flow model, with feeder resistance and reactance explicitly included. Constraint (10) imposes feeder apparent power limits, while (11) enforces a minimum power factor requirement. Voltage regulator operation is modeled in (12)-(15), capturing voltage drops, step changes, and downstream adjustments. Constraints (16)-(19) restrict regulator taps within allowable bounds, ensuring discrete and feasible settings.

Equations (20)-(23) define logical asset constraints. Equation (20) links investment decisions with operational availability and associated maintenance obligations. Equation (21) restricts each feeder corridor to either the existing line or a new installation. Equation (22) applies an equivalent exclusivity condition to transformer assets. Equation (23) enforces that only one substation option, existing or new, is active at each location.

4) Intermittent generation and storage constraints

Equation (24) updates storage state of charge with charge/discharge efficiencies. Equation (25) forbids simultaneous charging and discharging. Equation (26) bounds wind output by wind speed: zero below cut-in and above cut-out, quadratic ramp to rated, then constant at rated until cut-out [14]. Equation (27) bounds PV output by installed capacity scaled by normalized irradiance. Constraints for DG and ESS are presented as follows:

a) Energy Storage:

$$\mathrm{SoC}_{s,t,a,\mathrm{n}} = SoC_{s,t,a,n}^{Initial} + \eta_a \cdot P_{t,s,a,n}^{cESS} - \frac{P_{t,s,a,n}^{dESS}}{\eta_a} \tag{24}$$

$$P_{t,s,a,\mathrm{n}}^{dESS} \cdot P_{t,s,a,n}^{cESS} = 0 \tag{25}$$

b) Wind generation:

$$\sqrt{P_{s,t,a}^{DG}{}^2 + Q_{s,t,a}^{DG}{}^2} \le \begin{cases} 0 & WS_t \le V_{in} \\ \left(\frac{WS_t{}^2 - V_{in}{}^2}{V_{out}{}^2 - V_{in}{}^2}\right) \cdot C_{t,s,a}^{DG} & V_{in} < WS_t \le V_{rated} \\ Ca_{t,s,a}^{DG} & V_{rated} < WS_t \le V_{out} \\ 0 & WS_t > V_{out} \end{cases} \tag{26}$$

c) Solar generation:

$$P_{s,t,a}^{DG}{}^2 + Q_{s,t,a}^{DG}{}^2 \le (Ca_{s,t,a}^{DG} \cdot SI_t)^2 \tag{27}$$

5) Power limit constraints

Equations (28)-(35) impose capacity limits on network and DER assets. Constraints (28)-(29) bound feeder active and reactive power flows by their respective thermal ratings. Similarly, (30)-(31) restrict transformer active and reactive power within allowable limits. Equation (32) ensures CG output does not exceed installed apparent capacity. Constraint (33) maintains the state of charge of ESS within its rated energy capacity, while (34) enforces charging and discharging power limits relative to installed ESS capacity. Finally, (35) bounds the reactive power support of SC by their rated capacity. Fig. 1 shows the high-level workflow of the proposed framework.

$$|P_t^{i,j}| \le P_{limit}^{IF} \cdot l_{i,j,t}^F + \sum_{a \in \mathcal{G}_F} P_{limit}^F \cdot y_{i,j,s,t,a}^F \tag{28}$$

$$|Q_t^{i,j}| \le Q_{limit}^{IF} \cdot l_{i,j,t}^{\mathrm{F}} + \sum_{a \in \mathcal{G}_F} Q_{limit}^F \cdot y_{i,j,s,t,a}^F \tag{29}$$

$$|P_t^{i,j}| \le P_{limit}^{ITR} \cdot l_{i,j,t}^{\mathrm{TR}} + \sum_{a \in \mathcal{G}_{TR}} P_{limit}^{TR} \cdot y_{i,j,s,t,a}^{TR} \tag{30}$$

$$|Q_t^{i,j}| \le Q_{limit}^{ITR} \cdot l_{i,j,t}^{\mathrm{TR}} + \sum_{a \in \mathcal{G}_{TR}} Q_{limit}^{TR} \cdot y_{i,j,s,t,a}^{TR} \tag{31}$$

$$P_a^{CG^2} + Q_a^{CG^2} \le Ca_a^{CG} \tag{32}$$

$$0 \le SOC_a^{ESS} \le Ca_a^{EESS} \tag{33}$$

$$(P_a^{dESS} - P_a^{cESS})^2 + Q_a^{CG^2} \le Ca_a^{PESS} \tag{34}$$

$$0 \le Q_a^{SC} \le Ca_a^{SC} \tag{35}$$

IV. Results and Discussion

A. Test Systems, Data, and Assumptions

The evaluation uses the modified IEEE 123-node feeder (20 MVA, 23 kV). Analyses are in p.u. with voltage bounds [0.94, 1.06] and minimum power factor 0.95; voltage regulators have 32 taps with a 0.1 p.u. bandwidth. Economic inputs assume a 5% discount rate and 2% annual inflation, with a wholesale price of \$0.03/kWh. Wind generation employs $V_{in} = 3, V_{rated} = 12$, and $V_{out} = 25$; solar irradiance and wind speed profiles are forecast over the planning horizon. Load growth scenarios of 2%, 4%, and 8% per year are considered. The initial state of charge of the ESS is set to 30%. The model is implemented in Python and solved with Gurobi on an AMD EPYC 9654 (112 cores, 750 GB RAM). The resulting model comprises 202,928 continuous and 27,336 integer variables and is solved in 14 minutes. Tables III–IV summarize the technical and economic inputs used for DER and substation assets, and for network components, respectively.

B. Results

For benchmarking, the formulation in [4] was adopted as the closest available reference to the proposed model. Notably,

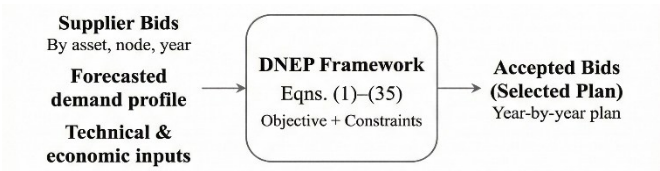

Figure 1. High-level workflow of the proposed DNEP framework

reactive-power compensation and substation upgrade options are not supported in [4], whereas both are enabled in this study.

Across all load-growth cases, enabling reactive-power support reshapes the portfolio, reliance on shunt capacitors declines because DERs supply reactive power. Adding substation bids makes competition among options realistic by enforcing full technical and operational limits; at 4% and 8% growth, DERs demonstrably defer conventional reinforcements. Both models use peak-hour planning, yet the benchmark selects many ESS units, despite the practical difficulty of meeting simultaneous minimum-SoC requirements. Crucially, although a new term is added to the objective function, the proposed model delivers lower total capital and maintenance costs than the benchmark at 4% and 8% growth. Explicit modeling of DER VAR capability and substation expansion widens feasible choices while reducing overall cost and preserving operational viability. Fig. 2 shows the optimal asset allocation across all load growth scenarios.

Table II compares CapEx and O&M for the proposed model and benchmark [4], showing savings at 4% and 8% growth. Figs. 3 and 4 show the cumulative investment and maintenance cost trajectories under 4% and 8% load growth, respectively, where the proposed model achieves consistently lower long-term expenditures compared to the benchmark.

C. *Discount Rate Sensitivity Analysis*

The base case adopts a 5% discount rate, and sensitivity cases at 4% and 7% are examined to quantify the effect of discounting on investment timing and lifecycle costs. Compared to 5%, the 7% case results in the same portfolio of installed assets because binding technical constraints ultimately require these reinforcements; however, a larger share of investments is shifted to later years as near-term capital becomes less attractive in present-value terms. For both 4% and 7%, the proposed formulation continues to deliver lower total investment and maintenance costs than the benchmark. At 4%, essential assets are selected earlier to satisfy operational limits, while less critical upgrades are deferred, maintaining the observed cost advantage.

TABLE II. CAPEX + O&M COMPARISON FOR REFERENCE [4] AND PROPOSED MODEL ACROSS LOAD GROWTH SCENARIOS

Load Growth	Metric	Ref [4]	Proposed Model	Savings vs. Proposed
2%	CapEx + O&M ($)	13,945,646	**13,714,643**	**1.7 %**
4%	CapEx + O&M ($)	26,168,755	**23,859,872**	**8.8 %**
8%	CapEx + O&M ($)	65,965,268	**57,562,347**	**12.7 %**

TABLE III. TECHNICAL AND ECONOMIC PARAMETERS FOR DER ASSETS (ESS, SC, CG, DG) AND SUBSTATION

Asset	Number of bids	Node ID	Capacity	Maintenance Cost	CapEx	Lifetime (years)	Additional information
ESS	1700	1-114	1,000-1,500 (kW) / 2,000-3,000 (kWh)	12-15 ($/kW-yr)	400 ($/kW) / 200 ($/kWh)	10-15	95%-96% efficiency rate,
SC	1700	1-114	1,000-1,800 (kVAr)	7-10 ($/kVAr-yr)	25-40 ($/kVAr)	20	-
CG	1700	1-114	3,000-5,000 (kW)	15-30 ($/kW-yr)	1,200-1,500 ($/kW)	20	-
DG	1700	1-114	800-1,600 (kW)	15-25 ($/kW-yr)	900-1,400 ($/kW)	20-25	Wind generation and solar panels
Sub	20	150	40,000 (kVA)	11 ($/kVA-yr)	210 ($/kVA)	30	-

TABLE IV. TECHNICAL AND ECONOMIC PARAMETERS FOR FEEDER AND TRANSFORMER ASSETS

Asset	Number of bids	From Node	To Node	Resistance (p.u.)	Reactance (p.u.)	Active Power Limit (p.u.)	Reactive Power Limit (p.u.)	CapEx ($)	Lifetime (years)
Feeder	2478	All feeders included		0.0025-0.05	0.0058-0.059	3	1.5	500,000	30
Transformer	2478	All transformers included		0.0025-0.05	0.0058-0.059	3	1.5	1,000,000	30

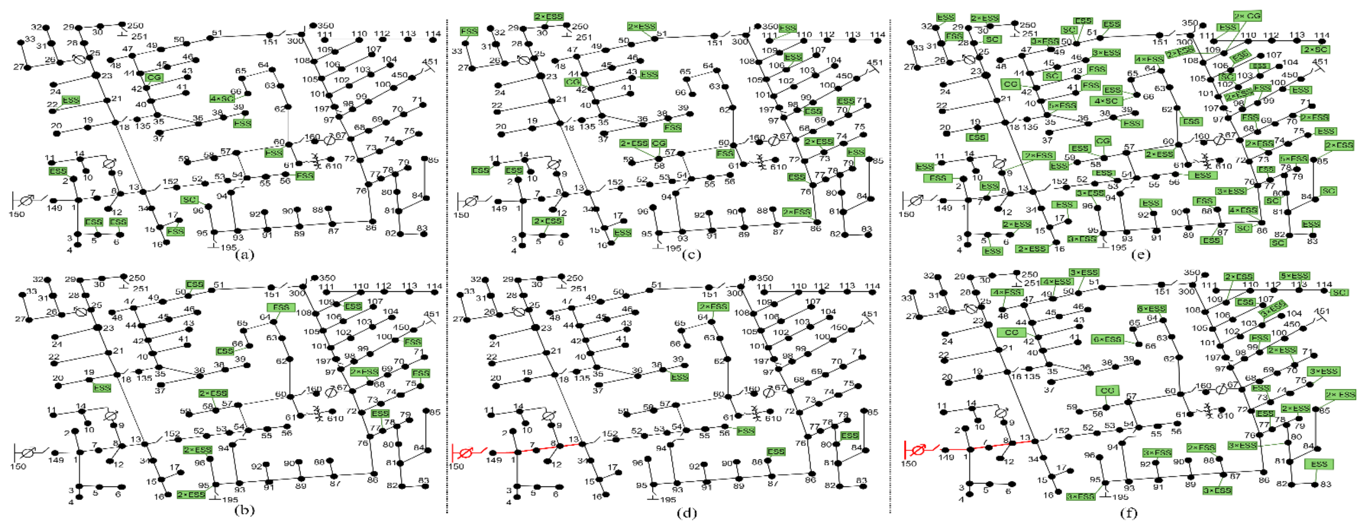

Figure 2. Optimal asset allocation under different load growth scenarios: (a), (c), (e) benchmark model [4]; (b), (d), (f) proposed model for 2%, 4%, and 8% load growth, respectively

979-8-3315-8138-1

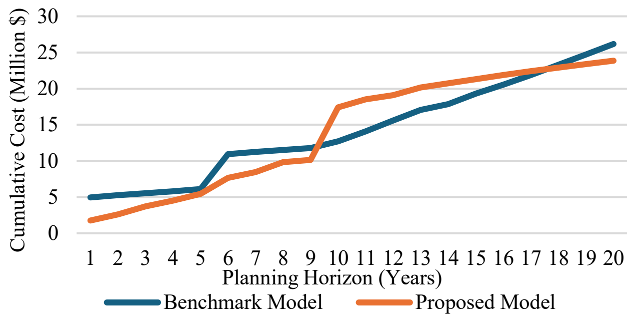

Figure 3. Cumulative investment and maintenance costs under 4% load growth

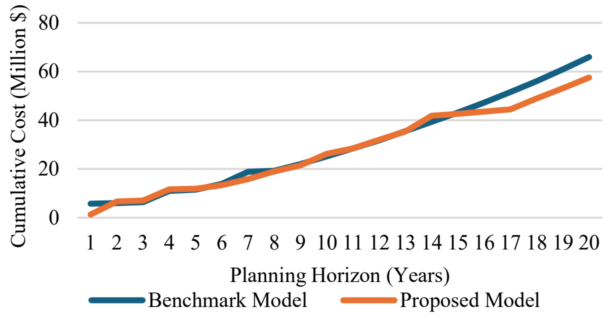

Figure 4. Cumulative investment and maintenance costs under 8% load growth

TABLE V. PLANNING HORIZON SENSITIVITY OF CAPEX AND O&M COSTS

Planning horizon	Load Growth	Metric	Ref [4]	Proposed Model	Savings vs. Proposed
10 years	**4%**	CapEx + O&M ($)	10,041,689	**9,708,846**	**3.3 %**
	8%	CapEx + O&M ($)	21,683,673	**15,385,372**	**29 %**
15 years	**4%**	CapEx + O&M ($)	17,348,799	**16,708,326**	**3.7 %**
	8%	CapEx + O&M ($)	40,591,292	**32,775,044**	**19.3 %**

D. *Planning Horizon Sensitivity Analysis*

To investigate how discounting affects cost visibility over time, sensitivity analyses were performed for 10- and 15-year horizons. In the 20-year case (Figs. 3-4), the proposed model's cost advantage becomes apparent mainly in later years because the net present value formulation discounts future expenditures, masking early-year benefits. However, as shown in Table V, shorter horizons still demonstrate tangible savings—especially under high (8%) load growth—indicating that the proposed framework remains effective even when long-term discount effects are less pronounced. These results confirm that the model's early investment strategy yields sustained cost efficiency across both short- and long-term planning horizons, reinforcing its robustness under deep electrification scenarios.

V. CONCLUSION

This paper presented a competitive, long-horizon DNEP framework that models DERs and network reinforcements as bid-based assets, internalizes reactive-power support via a loss-cost term, and includes substation expansion under deep electrification. Applied to the modified IEEE 123-node feeder, the proposed model reduces reliance on shunt capacitors through DER-provided reactive support, defers conventional reinforcements at 4% and 8% load growth, and achieves lower total costs despite the added objective term. Sensitivity analyses for shorter planning horizons confirmed that although discounted benefits appear mainly in later years, the model still yields measurable cost savings—especially under high load growth—demonstrating robustness across both short- and long-term horizons. Future work will extend the framework to chronological, multi-period operation with intertemporal ESS dynamics and uncertainty modeling via stochastic or robust optimization.

REFERENCES

[1] L. Xie, T. Huang, P. R. Kumar, A. A. Thatte, and S. K. Mitter, "On an Information and Control Architecture for Future Electric Energy Systems," *Proc. IEEE*, vol. 110, no. 12, pp. 1940–1962, Dec. 2022, doi: 10.1109/JPROC.2022.3218276.

[2] J. Ma, "Growing the power system: Expansions on transmission and distribution systems for deep electrification," *iScience*, vol. 28, no. 6, Jun. 2025, doi: 10.1016/j.isci.2025.112662.

[3] F. L. Muller, J. Szabo, O. Sundstrom, and J. Lygeros, "Aggregation and Disaggregation of Energetic Flexibility From Distributed Energy Resources," *IEEE Trans. Smart Grid*, vol. 10, no. 2, pp. 1205–1214, Mar. 2019, doi: 10.1109/TSG.2017.2761439.

[4] M. A. Mirjalili and J. Ma, "A Competitive Techno-Economic Framework for Distribution Network Expansion Under Deep Electrification Considering Flexible Resources," presented at the 2025 IEEE Electrical Power and Energy Conference (EPEC 2025), Waterloo, ON, Canada: IEEE, Oct. 2025.

[5] K. Turitsyn, P. Sulc, S. Backhaus, and M. Chertkov, "Options for Control of Reactive Power by Distributed Photovoltaic Generators," *Proc. IEEE*, vol. 99, no. 6, pp. 1063–1073, Jun. 2011, doi: 10.1109/JPROC.2011.2116750.

[6] P. Jahangiri and D. C. Aliprantis, "Distributed Volt/VAr Control by PV Inverters," *IEEE Trans. Power Syst.*, vol. 28, no. 3, pp. 3429–3439, Aug. 2013, doi: 10.1109/TPWRS.2013.2256375.

[7] E. Dall'Anese, S. V. Dhople, B. B. Johnson, and G. B. Giannakis, "Decentralized Optimal Dispatch of Photovoltaic Inverters in Residential Distribution Systems," *IEEE Trans. Energy Convers.*, vol. 29, no. 4, pp. 957–967, Dec. 2014, doi: 10.1109/TEC.2014.2357997.

[8] A. Tabares, G. Muñoz-Delgado, J. F. Franco, J. M. Arroyo, and J. Contreras, "Multistage reliability-based expansion planning of ac distribution networks using a mixed-integer linear programming model," *International Journal of Electrical Power & Energy Systems*, vol. 138, p. 107916, Jun. 2022, doi: 10.1016/j.ijepes.2021.107916.

[9] T. F. Agajie, B. Khan, H. H. Alhelou, and O. P. Mahela, "Optimal expansion planning of distribution system using grid-based multi-objective harmony search algorithm," *Computers & Electrical Engineering*, vol. 87, p. 106823, Oct. 2020, doi: 10.1016/j.compeleceng.2020.106823.

[10] A. Arif and J. Milanovic, "Data-Driven Distribution System Expansion Planning Considering High EV and PV Penetration," in *2021 IEEE PES Innovative Smart Grid Technologies Europe (ISGT Europe)*, Espoo, Finland: IEEE, Oct. 2021, pp. 01–05. doi: 10.1109/ISGTEurope52324.2021.9639991.

[11] M. Kabirifar, M. Fotuhi-Firuzabad, M. Moeini-Aghtaie, N. Pourghaderi, and P. Dehghanian, "A Bi-Level Framework for Expansion Planning in Active Power Distribution Networks," *IEEE Trans. Power Syst.*, vol. 37, no. 4, pp. 2639–2654, Jul. 2022, doi: 10.1109/TPWRS.2021.3130339.

[12] H. Yao, Y. Xiang, and J. Liu, "Virtual Prosumers' P2P Transaction Based Distribution Network Expansion Planning," *IEEE Trans. Power Syst.*, vol. 39, no. 1, pp. 1044–1057, Jan. 2024, doi: 10.1109/TPWRS.2023.3240830.

[13] K. Zou, A. P. Agalgaonkar, K. M. Muttaqi, and S. Perera, "Distribution System Planning With Incorporating DG Reactive Capability and System Uncertainties," *IEEE Trans. Sustain. Energy*, vol. 3, no. 1, pp. 112–123, Jan. 2012, doi: 10.1109/TSTE.2011.2166281.

[14] N. Gupta, "A review on the inclusion of wind generation in power system studies," *Renewable and Sustainable Energy Reviews*, vol. 59, pp. 530–543, Jun. 2016, doi: 10.1016/j.rser.2016.01.009.

979-8-3315-8138-1