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Research to develop the next generation of electric power capacity expansion tools: What would address the needs of planners?

P. Maloney[a,*], P. Chitkara[b], J. McCalley[a], B.F. Hobbs[b], C.T.M. Clack[c], M.A. Ortega-Vazquez[d], A. Tuohy[d], A. Gaikwad[d], J. Roark[d]

[a] Iowa State University, United States
[b] Department of Environmental Health & Engineering, The Johns Hopkins University, United States
[c] Vibrant Clean Energy, LLC, United States
[d] Grid Operations and Planning, Electric Power Research Institute, United States

ABSTRACT

Close coordination between generation and transmission operations and planning is critical to cost effective and reliable energy production and delivery; such coordination, in the presence of ownership diversity, is indeed a primary and challenging goal of regional transmission organizations in the US and similar organizations worldwide. Optimizing these sectors separately overlooks potential synergies that may allow for more effective design and operation of power systems. Coordinated expansion planning (CEP), where both generation and transmission decisions are coordinated, has become especially relevant to present day planning and operations. There are various reasons for this, some of which include the desire to obtain the most environmental and economic benefit from deeper penetration of renewable energy sources, the need for effective deployment of emerging storage technologies, opportunities to capture and harness the electrification of the transport sector, increased interdependencies with other sectors (e.g., gas), and accommodating increased shares of distributed energy resources in distribution grids. These changes result in increased short-term and long-term uncertainties, as well as an increased need for improved representation of multiscale temporal and spatial dynamics (e.g., representing hourly or sub-hourly intertemporal couplings in multi-decadal expansion models). The purpose of this work is to characterize the state-of-the-art in CEP models and identify technical challenges of grid development planning and research and development (R&D) needs for the new generation of these CEP models.

1. Introduction and overview

The material of this work (sections 1–10 and abstract) is adapted from [1] with permission from The Electric Power Research Institute. It consolidates [1] to make key points from this material available in a journal format while also extending the insights of [1] in several areas.

Because electric power system infrastructure (i.e., generation, transmission, and distribution components) is capital-intensive and long lived, planning decisions must be assessed carefully before making commitments that are difficult to reverse. Expansion planning is a general term that refers to the processes associated with this assessment and subsequent decisions. Expansion planning is typically performed over a time interval of ~10–40 years which is referred to as the decision horizon. The ultimate aim of expansion planning is to identify infrastructure investments in terms of technologies, amounts, locations, and timing that minimize the present value of revenue requirements (or costs in a restructured environment). These include capital costs of new investments plus fixed and variable production cost over the decision horizon. Central to this aim is that the infrastructure investments are generally comprised of multiple technologies, and so the investment result when combined with existing technologies, can be considered as a technology portfolio. Coordinated expansion planning (CEP) tools, which combine both generation and transmission planning, facilitate this process by providing information on how alternative investments enhance or restrict the flexibility of the grid to respond to possible long-run technological, economic, and policy developments. These expand upon traditional resource planning tools to also consider transmission in a coordinated fashion. Because CEP also models supply-side and distributed energy options, it can effectively support the integrated resource planning processes as well as proactive grid planning [2] by anticipating how diverse supply, storage, demand-response, and transmission participants will change where, when, and what investments they make.

The objective of this work is to identify the technical challenges of grid development planning and R&D agenda that would, upon execution, bring CEP tools to a maturity level to enable their day-to-day use within electric infrastructure planning organizations, for traditional and extended planning functions. This agenda is covered in the following nine sections. Section 2 describes CEP modeling needs driven by markets and revenue adequacy needs. Section 3 identifies four needs for

* Corresponding author at: Richland, WA, United States.
E-mail addresses: patrickm@iastate.edu (P. Maloney), maov@epri.com (M.A. Ortega-Vazquez).

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additional modeling fidelity within the CEP: production simulation, distribution representation, congestion management, and effects of short-circuit currents. Section 4 addresses methods for representing uncertainty. Section 5 outlines sources of computational complexity and solution methods to alleviate it. Section 6 describes the need for, and methods to, include weather effects within the CEP. Section 7 examines representation and analysis of resilience. Section 8 focuses on multi-sector modeling, i.e., the inclusion of additional infrastructure systems such as natural gas networks and transportation systems within the CEP. Section 9 identifies characteristics of software needed to validate plans post simulation. Section 10 concludes.

2. Modeling for markets and renewables

The ongoing grid transformation from fossil-fueled resources to renewable resources is forcing adjustments to CEP applications. Use of CEP in unbundled markets is equivalent to assuming that the transmission planner is anticipating the investment and operations reactions of a competitive energy market; this perspective can account for market failure, as well as the changes brought by large amounts of zero-marginal-cost variable renewables. The use of CEP models by planners in an "anticipative/proactive" mode assumes that decisions not under the planner's control can be predicted. If it is assumed that the latter decisions are made in a perfectly competitive environment, then the planner can use a CEP formulated as a single optimization model with an objective of maximizing net benefits [3]. However, there are many "market failures" which mean that, at best, the perfect competition assumption is a useful approximation and, at worst, the assumption results in large distortions in the results. Some failures can prevent potential investors from responding to market fundamentals in the way anticipated by proactive CEP models. These include nonconvexities, financial market incompleteness, environmental externalities, imperfect coordination among subregions, and pricing distortions. More elaborate anticipative models based on bilevel programming can be used to model generator and other reactions when these market failures are present, but are presently difficult to scale and solve. A particular issue, in markets across Europe and the US, is that energy prices have been driven downwards by the rapid expansion of solar and wind capacity. Regulators, market designers, and especially market participants are asking how investments in needed resources can be supported in this situation, especially if energy prices are capped or long-run contract markets are limited. A useful perspective on this problem can be obtained by considering a CEP that has two features not traditionally included in capacity expansion models: (1) demand curves and curtailment penalties and (2) co-optimized reliability services. For the first feature, if CEP considers price-elastic demand, in which higher prices result in voluntary load reduction, or involuntary curtailment with a penalty level that reflects the value of lost load, then market prices rise during periods of scarcity. Such scarcity pricing can, in theory, incentivize the optimal mix of generation investment [4]. In a market with frequent zero or negative prices as a result of renewables, the outcome will be price spikes during scarcity periods, signaling the need for investment. In regards to the second feature, if frequency regulation, operating reserve, and ramping needs of a market are captured by explicit representation of the requirements and supply of these commodities, and realistic penalties for any shortfalls, then these can be significant revenue streams for new investments. Incorporation of explicit demand curves for these services, in which marginal penalties for non-supply increase as the shortfalls grow, allows scarcity to be reflected in market prices for energy, even if loads themselves are treated as fixed.

Under the above assumptions, and if the CEP is a convex optimization problem (a strong assumption), the cost-minimizing/benefit maximizing plan yielded by a CEP is supported by the prices of the energy and other commodities. That is, every investment will earn revenues from the energy and reliability services markets equal to or greater than its investment and operating costs, where prices are calculated by the shadow prices of the market-clearing constraints for the various commodities in the market [4], and no investor can change their decisions and earn a higher profit under those prices. Despite the high frequency of zero or negative prices, there will be enough price spikes and high enough compensation for ancillary services that the right amount of each generation type, as well as storage and demand-side investments, will, in theory, be supported by the prices. Complemented by fully-functional financial markets, in which those who desire long-term contracts or other hedges against short-term risks can buy them, well-designed short-term markets for energy and ancillary services can, in theory, provide most or all of the revenues needed for optimal investments from CEP. However, spot markets have limitations, manifested as market failures; which render this supporting-price result less credible and cast doubt on whether spot markets are likely to be sufficient.

An alternative being discussed in some policy circles [5] to dealing with the revenue issues that arise in markets with high renewables is to expand the role of CEP models. In this proposal, their role would expand from merely suggesting transmission and other investments to running auctions, similar to today's capacity markets. They would instead, allow for the full range of Integrated Resource Planning (IRP) options, so that transmission and alternative resources (supply- and demand-side) would compete against each other by submitting offers which, if cleared by the planning model, would be awarded long-term contracts based on the shadow prices for the constraints in the model. Both existing resources and possible new resources would compete. The goal is to overcome a major market failure: the lack of a robust market for long-term capacity commitments. Investors whose offers are accepted would receive certain financial guarantees in exchange for obligations to maintain the existing resources or build the new ones. Transmission proposals that are accepted would also receive guarantees.

There are many important R&D questions that concern the interaction of planning methods and markets. Examples include: Can differences in nature and timing of investment be explained in terms of the differences in wholesale market design? What market designs incentivize better regional coordination across control areas, which should lead to (i) more effective integration of new renewables, (ii) lower operational costs and (iii) more efficient investment? How do differences in mechanisms for allocating transmission charges impact supply investment?

Separate and decentralized ownership of generation, transmission, and distributed supply and storage systems raises questions about how CEP modeling can help coordinate the interests and actions of the various market parties. By modeling the interests and strategies of participants in electricity markets, can CEP models address the incentives for efficient participation, also called "incentive compatibility?" Incentive compatibility is when financial incentives make participation and investment profitable when such participation would increase the overall economic efficiency of the market, while at the same time discouraging participation and investment when it would not benefit the market as a whole. There are several levels of incentives. For example, regulators (e.g., the Federal Energy Regulatory Commission (FERC), state commissions, and ISOs) provide investment incentives in wholesale markets in the form of rates-of-return and permitting, and also encourage cooperation among neighboring systems, as in FERC's Order 1000. In turn, transmission owners and operators provide incentives for building and siting assets by their interconnection rules, pricing for transmission services, and creation of zones for acquiring ancillary services. Meanwhile, retail ratemaking provides critical incentives for distributed energy production in retail ratemaking. Bringing together research on CEP modeling with the economic literature on incentives (as described in [6]) could provide theoretical frameworks that are practical and effective for encouraging efficient mixes, locations, and types of investment. The following ideas are core in incentive theory. Conflicting objectives and decentralized information, which are key characteristics of electricity system governance, are two integral ingredients. Another core idea is that each market party–consumers, load serving entities system operators, grid owners, or generation investors— pursue their private interests which are shaped by incentives. Though the incentive theory paradigm has limitations, its practical application would be a step towards increasing relevance and effectiveness of CEP models.

A specific set of questions arise if CEP is considered as a framework for investment auctions. What then would be the relationship of settlements in the CEP-administered long-term market and spot markets? What would be the role of imbalances and how would they be settled, both in short-term markets and longer-term investment obligations? How would obligations be enforced, since bankruptcy might be a tempting hedge for new projects? How would long-run policy, economic, and technology uncertainties be factored into the auction? Who would be responsible for revenue inadequacies for the auction that could result from, for instance, load growth that does not materialize, or up-front payments to resources that are not built?

3. Enhanced modeling fidelity

This section addresses four modeling features where expansion planning applications require enhancements. These features are production simulation (PS), distributed energy resources (DER), congestion management, and the influence of short circuit current levels.

To account for flexibility requirements while maintaining computational tractability, CEP must provide for chronological representation of operating conditions. One approach is to employ a chronological Production Simulation (PS) in the CEP, and implement methods to relieve computational intensity. Another approach is to provide, as an R&D objective, that a standard (with non-chronological "internal" PS) CEP iterate with an "external" (chronological) PS, perform a performance test in each iteration, and then (when over- or under-performing) identify adjustments to CEP constraints necessary to achieve desirable performance in the next iteration of the external PS. Such an approach is illustrated in Fig. 1.

Given the current interest in Distributed energy resources (DER), greater modeling efforts should be made to adequately analyze and capture their effect within PS embedded on the bulk system expansion through the displacement of energy and flexibility services and through loss reduction. If DER is modeled as a decision variable, then this influence may also come through competing infrastructure investments. One way to capture these three influences is to represent each transmission-level load bus with a single distribution feeder having a limited number of segments, e.g., three, as illustrated in Fig. 2. This approach enables the capture of losses, the need for feeder capacity expansion, the effect of distribution load and DER at different electrical distances from the transmission bus, and the performance evaluation of portfolios of options to provide support at the distribution level during high-load, low solar time periods. More extensive distribution systems may be modeled as well, but in such case, a decomposition-by-network partition (possibly one node for each transmission load bus), with parallel programming, is necessary to maintain computational tractability. This suggests an R&D goal is to implement within the CEP a high degree of flexibility in representing the distribution network topology at each bulk system load bus, with options for automatic or manual feeder representation, a goal which leads to identifying what degree of distribution-related modeling is needed.

Congestion management methods are often classified as cost free or non-cost free. According to [7], cost free includes activities with small marginal operational costs such as operating FACTS devices while non-cost free techniques would include re-dispatch of generation or curtailment or loads. More granular stratifications of congestion management divide methods into four categories: sensitivity factors, auction based, pricing mechanisms, redistribution and willingness to pay [8]. A useful research and development agenda of congestion management method would determine what methods are most effective at reducing costs, as well as what methods can be accommodated by computationally tractable models. For example, with regard to the classifications of [7], non-cost free approaches are closely related to accurately capturing a subset of the PS operational setpoints to simulate over since representing all setpoints is generally considered intractable. Different methods have been proposed [9,10]. However, given each method will choose a different subset of operational setpoints, can we determine a single method as being fundamentally superior or does PS operational setpoint selection need to be tailored to the specific system and model constraints under study? With regard to cost free approaches, such as FACTS, long term planning studies are often conducted using Direct Current (DC) power flow model contained with the PS to remain computationally tractable. However, the full benefits of many FACTS devices cannot be realized in DC power flow formulations since it does not capture voltage variation or reactive powerflows. Research into moving long-term planning studies into AC powerflow or approximating the full benefits of FACTS devices without requiring an AC powerflow would be useful.

A final modeling improvement is to account for changing short circuit currents (SCCs). There are two reasons which motivate this need. First of all, the addition of new synchronous generation in the network, together with additional transmission, causes SCCs to increase. To avoid violating constraints representing circuit breaker and transformer ratings, fault current limiters may be needed, resulting in additional investment cost to be included in the objective function [12]. Recent research in this area includes [11], which implements a novel Benders decomposition application. Within this work the master problem determines the transmission expansion plan and a linearized short circuit analysis is performed in one of 3 sub-problems. In [12], short circuit levels are taken into account within a transmission and generation expansion plan with emphasis on wind farms. In contrast to [11,12,13] does not focus on capital investments but rather substation topology changes such as bus splitting to reduce short circuit levels. What this body of research suggests is that short circuit levels are an important security consideration for properly sizing equipment which affects total investments costs and optimal geographic placement of new investments.

SCCs also have significance with respect to expansion planning as a

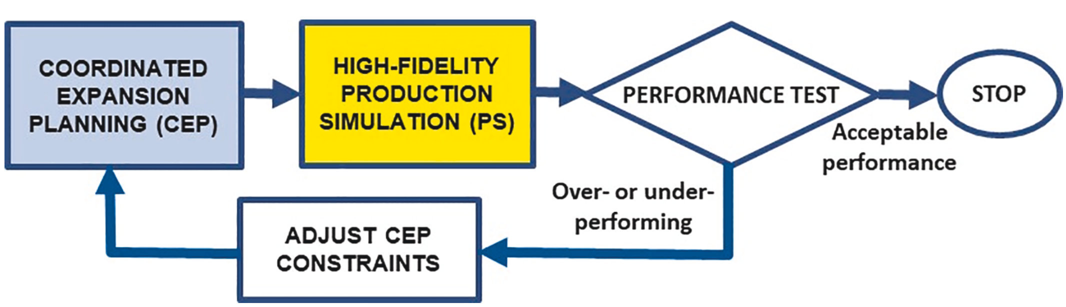

Fig. 1. CEP with external chronological production simulation to ensure flexibility (Adapted from [1]).

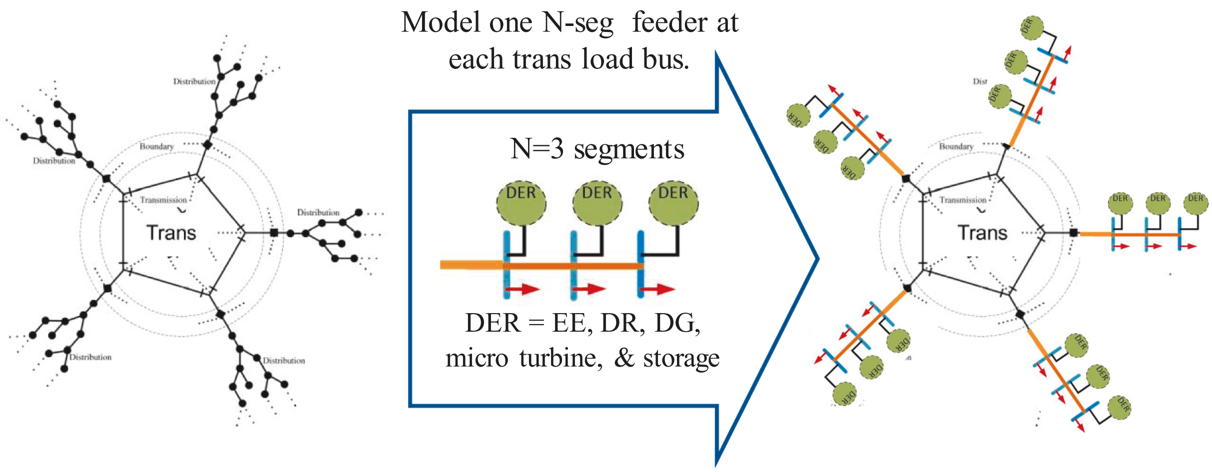

Fig. 2. DER modeling approach (Adapted from [1]).

metric associated with bus stiffness. As the amount of synchronous generation is reduced, replaced by inverter-based (asynchronous) generation, SCC tends to reduce (alleviating the excessive SCC problem addressed in the previous paragraph); but it also results in so-called "weak grid" conditions. This is particularly the case where inverter based resources are located in regions with low short circuit strength due to sparse transmission and relatively few synchronous resources in the region [14]. These low short circuit conditions can cause challenges related to inverter controls, where bus voltage stiffness is reduced and the phase-locked loop of grid-following inverters may not properly operate [15]. This can result in voltage instability. Screening metrics have been developed, such as the Short Circuit Ratio (SCR), which compares the interconnected grid's short circuit MVA to the MW of the interconnection plant at the point of common coupling. A low SCR can indicate potential issues; however these are for single generator interconnections and may not illuminate situations where many plants are interconnecting. Therefore other metrics are also often used, such as the Weighted Short Circuit Ratio developed by ERCOT [16], the combined SCR developed by GE [14], and a metric to examine critical clearing time developed by EPRI [17]. In cases where some or all of these metrics flag a potential instability issue, more detailed point on wave simulations may be needed for plant interconnection studies, and the inverter controls may need to be tuned to avoid instabilities. This effect may also motivate greater use of grid-forming inverters that are insensitive to this effect. As inverter-based resources continue to grow, addressing this influence will become increasingly important in long term planning studies, and suitable screening metrics could be used to flag potential additional costs, without necessarily needing to do full three phase studies. As an example, a screening tool such as the Grid Strength Assessment Tool developed by EPRI that runs with commercial positive sequence software tools could be used to screen potential issues based on outputs of a coordinated expansion plan, and relative costs assessed for additional control capabilities.

4. Uncertainty models for expansion planning

Because the future is uncertain (e.g., we do not know what natural gas fuel price will be in 5 years), there is a strong need to represent uncertainty within CEP models and capture its influence on decisions. As suggested in [18], uncertainties can be classified as either global or local. The authors of [18] interpret global uncertainties as the model parameters that have significant long-term impact capable of being represented by a long-term trend (e.g., a forecasted annual demand growth rate) and local uncertainties as the inherent randomness or short time scale fluctuations that occur around a long-term trend. Model parameters might have both attributes, e.g., a hydroelectric dam's 30-year production trend could significantly increase or decrease due to climate change while also exhibiting short term random fluctuations within its longer term trend.

One way to include uncertainty within a planning procedure is via a deterministic sensitivity analysis where the model is treated as deterministic but varied across several runs; each with a different set of model parameters. Upon conclusion of the runs, a second, separate optimization procedure or metric(s) is used to rank the plans or extract information from each plan into a master plan. California ISO employs such a procedure based on least regret [19] while Mid-Continent ISO has used a similar procedure in developing Multi-Value Projects (MVPs) [20].

Alternative approaches model many scenarios within a single optimization formulation, rather than optimize scenarios independently of each other. This is advantageous in that when faced with future uncertainty, it more realistically captures the need to sometimes make decisions that are non-optimal in any single scenario, but on average perform well when exposed to a variety of scenarios. These types of decisions are difficult to extract from a series of deterministic plans. The disadvantage, however, is the modeling of many scenarios within a single optimization framework is often significantly more computationally intensive than solving each of the scenarios separately in a sensitivity-analysis approach. Several approaches exist for this multi-scenario based planning method which include stochastic programming [3] and adaptive programming [18].

Fundamental to both approaches is the need for an appropriate scenario selection method. Widely used scenario selection methods are described in [21,22]. Multi-scenario-based planning is complicated by the significant increase in model size that comes with it, as moving from a deterministic scenario problem to a two-scenario stochastic-based problem often doubles the problem size. Furthermore, the process of scenario selection itself can become computationally intense. Thus, we observe that modeling uncertainty comes at significant cost. A metric for determining the value of model enhancements is developed in [23] that indicates that the value of uncertainty modeling may be greater than the value of improving fidelity in transmission, unit commitment, or time resolution.

In regards to uncertainty modeling, there are two major R&D issues to address. First, to facilitate scenario reduction, it would be useful to provide capability to identify uncertainties having the most impact on decision variables. Second, different ways of treating uncertainty lead to different decisions and/or decisions that are distinctly different. How does performance vary across tools, such as stochastic optimization, robust optimization, robust decision making, and adaptive

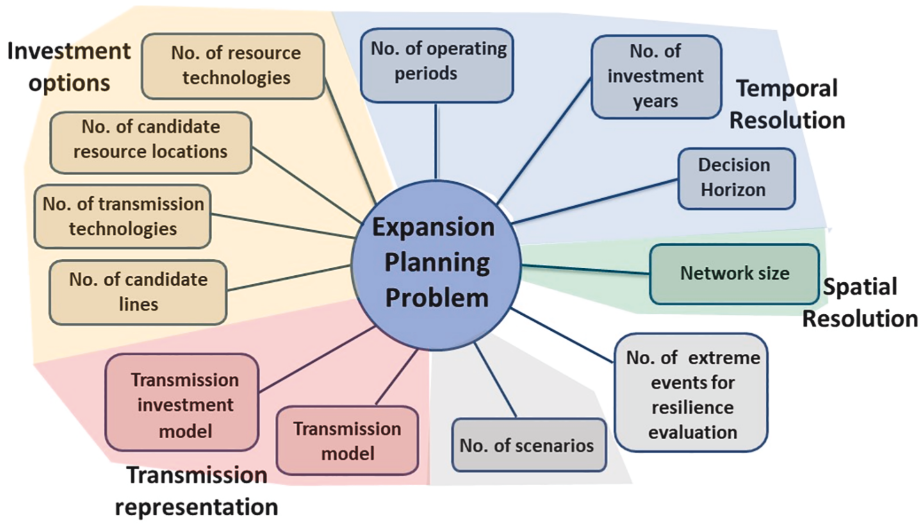

Fig. 3. Features affecting CEP compute time and model fidelity (Adapted from [1]).

programming in terms of, for example, accuracy, compute time, ability to decompose, risk metric performance, or ability to build robustness for both local and global uncertainties [23,24,50]? Do some uncertainty-based planning tools perform best in certain situations or with regard to particular metrics?

5. Computational complexity

A fundamental problem of solving the CEP is that greater model fidelity results in longer computational times. This is of particular concern because compute time growth can be exponential with problem size. Thus, a critical aspect of generating the planning model – that necessarily must compromise on model fidelity – is determining which features increase model fidelity the most, and which features provide the best return on fidelity per unit of computation. Developing a CEP analysis requires simultaneous consideration of all of these features, as increasing model fidelity in one dimension requires a decrease in one or more other dimensions to maintain acceptable compute time. The most influential features are illustrated in Fig. 3 and are further described below.

1. Temporal Resolution – The number of distinct operating conditions depends on the decision horizon together with its number of investment years, the number of purely operational years (and therefore unavailable for investments), and number of operating intervals as quantified by characteristic weeks, days, hours, or blocks per year.
2. Investment options –The number of investment options is determined by the number of competing resource technologies (including DER), the number of candidate resource locations, and the number of deployable circuit technologies (e.g., AC/DC and voltage class) and candidate locations.
3. Transmission representation – There are two transmission models that can be used: a transportation model or an impedance model. If a transportation model is used, then the transmission expansion model operates on only line capacities, so the problem remains a linear program (LP). If the higher-fidelity impedance model is used, the transmission expansion model may still operate only on line capacities and remain an LP, but in this case, impedances of expanded lines are inaccurate; fidelity is gained if a disjunctive transmission model is used, but at a significant computational expense, as the problem then becomes a mixed-integer LP [25]. A commonly used compromise is the hybrid model that employs an impedance model for existing transmission and a transportation model for new transmission [26]. Other variants include the binary disjunctive model [27] and iterative models.
4. Scenarios – In handling uncertainty, additional scenarios enhance the robustness of solutions to uncertainties but heavily increase computation time.
5. Number of extreme events – Inclusion of extreme events, for resilience evaluation, within the CEP can significantly increase computation time.
6. Network Size – One may represent the network in varying degrees of granularity, in terms of aggregation of buses, generators, loads, and circuits.

Adjustments of the previously described six categories of features are made through either the input data or through the planning model itself. Additional options exist for reducing compute time at higher levels of model fidelity. We describe two such methods, the first is deployment of decomposition algorithms; the second is to provide dynamic model resizing. There are various approaches for deploying decomposition methods, however, three that are prevalent throughout long term planning research include Benders [28], Danzig Wolf [29], and progressive hedging [30]. These methods rely on structural features of the problem that enable the full program to be broken into subproblems that are solved separately. Because compute time for mathematical programs can grow exponentially with problem size, the individual subproblems solve much faster than the full problem. This benefit comes with a cost, in that the solution procedure must iterate multiple times between master and subproblems. For problems with decomposable structure, which CEP problems generally have, the reduction in compute time for a single iteration usually outweighs the increased cost of multiple iterations. Related R&D directions includes deployment of multiple solution methods, as in [31] where Benders and Lagrangian relaxation were used, and as in [32] where two decomposition methods were nested with one operating on the subproblem of the other. Decomposition is also a natural step towards efficient parallelization via the inherent partitioning associated with subproblems. Another promising approach is to decompose by time period [33], geographical region [34], long-run scenario [35], or by a combination.

Dynamic model resizing (DMR) performs CEP on reduced-size models, but then at certain progressively increasing times during the decision horizon, generation and transmission investment results are translated to a full-size model. The reduced model is then redeveloped, a CEP is performed using the new reduced model with a time-shifted decision horizon, and the process is repeated. In Fig. 4, we illustrate this approach by combining it with the external production simulation of

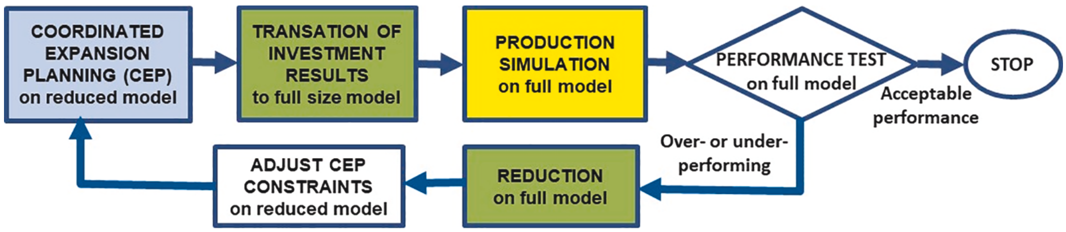

Fig. 4. CEP with external chronological production simulation and dynamic model resizing (DMR).

Fig. 1. Thus, this combined approach enables computational benefits from performing CEP on a reduced model while simultaneously maintaining modeling fidelity within the full-size model. In addition, instead of performing a single topology and temporal reduction based on the year-1 infrastructure and conditions [10], DMR accounts for the influence of model reduction on changes in infrastructure and conditions throughout the decision horizon.

An R&D objective central to these approaches is to develop a general systematic procedure for designing CEP solvers. Development of this procedure will require identifying model parameters that depend on the investments made during the decision horizon. For example, wind turbine capacity credit depends heavily on how much wind is installed and on its geographic diversity. On the other hand, rapid declines in solar technology costs might be considered independent of how much solar technology is installed in a specific grid as the technology is rapidly maturing and economies of scale are driven by global demand.

When model parameters are dependent on investments made during the decision horizon it may be advantageous to build break points at certain years into the optimization process to update model parameters to reflect that dependence. Dynamic model resizing has these break points naturally built into its procedure so that it can be used to increase model fidelity during them. While the break points eliminate the ability of the optimization procedure to have foresight past the break point, the loss of model fidelity from not updating model parameters may degrade solution quality more than the loss of this foresight when model parameters heavily depend on investment decisions. However, if model parameters are largely independent of investments made during the decision horizon then it may be advantageous to use decomposition methods as they generally do not have break points that can limit the optimization procedure's foresight and thus solution quality. The potential advantages listed for each method are hypothesized and quantitative experimentation, would allow for a deeper understanding of the appropriate use of each.

6. Weather

Individual weather events such as hurricanes, floods, and sustained extreme temperatures are often the focus of weather-related phenomena affecting the power grid. However, higher penetrations of renewables and demand side technologies requires increased focus on short and long term weather phenomena (as well as forecasting accuracy which can vary widely from one region to another) as it will likely impact which resources are the best options to build. While some weather effects are well-understood (such as wind power dependence on wind speed and solar irradiance variation due to clouds), others are less-so and therefore require appropriate attention within CEP models. This is particularly true for temperature, which impacts wind power through its effect on air density, solar power through its effect on solar cell temperature, thermal generated power through its impact on cooling water temperature, and load due to its impact on cooling/heating loads (which has been well-studied) but also through its impact on charging speeds for electric vehicles (which has not).

A second issue that requires consideration when CEP is used to study scenarios with deep penetrations of weather dependent technologies, is that the weather data used should select appropriate temporal and spatial dimensions. This is to ensure that that changes occurring during a time step can actually occur within the entirety of a single spatial cell. For example, a 200-km spatial resolution and a 1-minute temporal resolution is, together, a poor resolution choice because it represents 1 min changes in weather occurring throughout the entirety of a 40,000 km^2 region, phenomenon that is faster than any atmospheric wave can travel [36].

Finally, long term planning should account for climate change. An appropriate source of data for doing so includes the Coupled Model Intercomparison Project datasets [37]. Ideally, the CEP would evaluate representative concentration pathways to adjust the historical weather data based on climate values. The space of possible solutions could then be explored deterministically through sensitivity analysis or with stochastic multi-scenario-based methods.

There are three substantive R&D issues related to weather and CEP modeling. First, there is need to develop systematic methods for reducing weather model data such that it represents a granularity consistent with the temporal and spatial scales of the CEP model. Second, high value would result from an ability to mine such data to determine the weather phenomena most critical to power system operation. Third, when considering CEP decision horizons spanning multiple decades, investments identified early will, via their impact on greenhouse gas emissions, influence climate and subsequent meteorological conditions affecting power system operation, an issue further complicated in that it is a global rather than local phenomena. This raises the following question: Can scenario analysis capture the effects of climate change or does the feedback between investment decisions and climate change need to be modeled within the optimization formulation?

7. Resilience

The industry has traditionally designed and built electric infrastructure to satisfy so-called "credible" contingencies. These contingencies, generally including single and double-component outages, are specified by categories B and C of the North American Reliability Corporation (NERC)'s disturbance-performance table [38]. However, there are additional disturbance types that can result in significantly increased societal costs for weeks and months. Traditionally, such events have been classified as NERC Category D events with the only requirement being to "evaluate for risks and consequences" [38]. However, such events do occur, and the resulting system performance is highly influenced by the installed equipment and the integration of this equipment via system design. The term "resilience" is used to refer to system performance pertaining to survival and speed of recovery following such events [39].

Existing CEP models need the ability to identify design strategies for electric infrastructure, at both transmission and distribution levels, to enable improved performance under extreme events, in the context of four central concepts:

1. Performance for extreme events sets: Categories of high-impact low-probability events that drive resilience include natural disasters (including hurricanes, earthquakes, wildfires, floods, tsunamis, and geomagnetic disturbances), cyber-attacks, and cascading outages. A specific extreme event will uniquely influence infrastructure

operation resulting in event-specific impacts and costs. However, there are infrastructure design features that facilitate good performance across several, and possibly most, types of extreme events. For example, network connectedness (i.e., ratio of number of branches to number of nodes), is such a feature because it creates increased and redundant capacity to allow resource sharing across the network. To identify a resilience level for a particular power system, it is necessary to do so relative to an extreme event set.

2. Resilience-oriented design: The emphasis here is on identification of resilience-oriented design strategies, an emphasis born from the fact that CEP is an infrastructure design tool. Thus, it is desirable to incorporate within CEP the ability to identify good tradeoffs between cost, investments to facilitate normal operation, and investments to enhance resilience to extreme events (in terms of both the early impact as well as recovery period), while accounting for the interdependency between design and operations.
3. Operating conditions: Investments to enhance resilience are identified under extreme event conditions; yet, they also must be competed against investments that facilitate normal conditions. This requires that the CEP represent operating conditions within the decision-horizon to capture both extreme events and normal conditions. It may be necessary to weight within the objective function resilience-related benefits relative to expansion-related benefits.
4. Resilience upgrades: Certain expansion investments increase capacity in a way that simultaneously enhances resilience. However, some resilience upgrades do not enhance expansion, e.g., those that improve the ability of equipment to resist degradation. For example, transmission structures may be strengthened to reduce their failure probability during hurricanes, an action which enhances resilience but adds no capacity and therefore offers no benefit that can be captured by a CEP formulation that does not account for event probability. One may address this, on average over the planning horizon, by representing line capacity as P_{max}(1-FOR) where P_{max} is the circuit's MW rating, and FOR is the circuit's forced outage rate (which decreases with resilience enhancements). In addition, the relationships between resilience enhancements and their characterizations (e.g., through FOR reduction) within the expansion planning application are typically better-developed external to the CEP.

There are three main R&D issues associated with resilience modeling in expansion planning applications. First, there is need for developing criteria and guidelines for selecting a portfolio of specific extreme events to drive resilience evaluation. Second, one must model extreme events within the CEP to appropriately weigh their impact against that of capacity shortage during normal conditions. Third, technology options to enhance resilience for each extreme event type should be identified, and modeling should be developed that reflects the benefit of such technologies in the context of the objective function.

8. Multisector modeling approaches

Multisector models pertaining to the electric power system often seek to attain synergies between the electric power sector and natural gas, transportation, and/or water infrastructures. As described in [40], multisector models can be categorized as bottom-up, top-down, or hybrid models. As indicated in [40], bottom-up models such as [41] are generally optimizers, similar to CEP, that identify technology portfolios over time to minimize costs; such models incorporate explicit, refined descriptions of technologies and are generally preferred in engineering applications. Top-down models like [42] are macroeconomic [40]; they attempt to capture the performance of the energy-economic system rather than the behavior of individual firms. They usually include the influence of macroeconomic variables such as wages, consumption, and interest rates. Finally, hybrid models like [43] combine elements of bottom-up and top-down models [40].

Coupling infrastructures with the electric power sector is often touted as increasing grid flexibility [44] or reducing congestion [45] as operational and investment decisions are selected for optimal coordinated operation across infrastructures. Representative examples of multisector models that seek to combine the electric power system with natural gas, transportation, and water infrastructures include [46,47], and [48], respectively. In each of these examples the second infrastructure is largely connected to the electric power sector through a power-balance equation which ensures that at each node and time step energy is conserved. In [46], for each node in the system, net gas imports plus total gas production at each node is equated to the sum of electric and non-electric demands. In [47], transportation infrastructure is included in the power-balance equation of the long-term plan with the addition of a term for energy demand of transported commodities. Reference [48] also contains a power-balance equation at an interface node connecting the electric and secondary (in this case, water) infrastructure. In this work, demand is decomposed into all non-water-related demand and a decision variable that represents water-related demand. Within the water model the latter term is selected by the optimizer to allow greater flexibility for electrical system loads.

There are four R&D issues related to CEP multisector modeling. First, it is of interest to determine the mutual benefits of the top-down/bottom-up modeling approaches to identify the extent to which they should be deployed for use via a hybrid model. Second, modeling capability should be developed to capture the effects of inter-sector loading within the CEP, enhancing the fuel supply models used on the electric side and the supply demand elasticity on the natural gas side. Third, electric-water models should be developed to capture the water temperature effects on thermal plants; in addition, water related energy loads (e.g., water and wastewater treatment plants) should be studied to determine the extent to which they may offer demand flexibility for the grid. Finally, a modular, flexible multisector code should be developed that enables user-choice of sectors to model and a fidelity level for each sector.

9. Performance evaluation

The CEP identifies future system expansions to minimize overall costs while satisfying constraints on operations, investments, and environmental impacts. Because the plan is generated within an optimization framework, it performs well subject to the conditions (including uncertainties) under which it was produced. Because of the CEP's computational intensity, those conditions must necessarily be limited by allowing for selection of only a relatively few scenarios. For this reason, we desire a computationally inexpensive way to test and evaluate a plan and to compete one plan against another, under conditions independent of the ones for which each plan is generated. In effect, we need a sort of "virtual lab bench" on which we can experimentally test each theoretic (computed) plan, i.e., we need an objective way to evaluate plan performance.

There are six main attributes that facilitate a well-designed performance evaluation approach:

1. Out-of-sample scenarios: During the planning phase, scenarios are necessarily restricted to maintain satisfactory compute-times. Thus, we design the performance evaluation approach so that the plan is exposed to out-of-sample scenarios, i.e., scenarios that were not considered in developing the plan.
2. Monte Carlo Simulation: The performance evaluation should be able to expose the plan to a large number of out-of-sample scenarios. If the out-of-sample scenarios are generated based on distributions associated with the uncertainties, this becomes a Monte Carlo Simulation.
3. Recourse: The performance evaluation must be capable of adapting the original plan to provide model feasibility when exposed to especially stressful scenarios, capturing both benefits and costs of

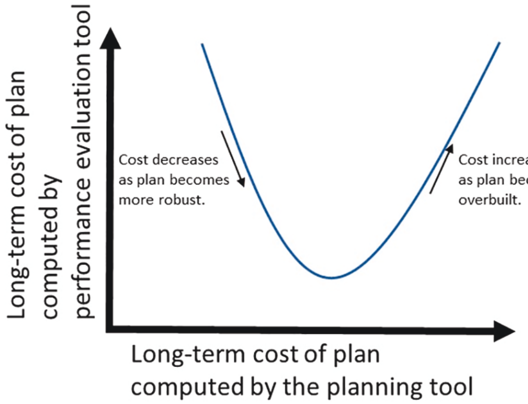

Fig. 5. Relationship of costs of plan from performance evaluation tool to costs of plan from planning tool.

strategies related to underbuilding and overbuilding. Thus, the tool identifies value in building robustly and value in restraining investment to avoid stranded investments. Recalling that the long-term cost of a plan computed by the planning tool is a function of only a limited number of (in-sample) scenarios, and the long-term cost of a plan computed by the performance evaluation tool is a function of many more (out-of-sample) scenarios, we might expect a mature performance validation tool to generate results that exhibit a "U"-shape similar to that shown in Fig. 5.

4. Lead time: Technology lead times are often approximated in CEP by assuming the delay between the decision to construct a new investment and when it becomes operational is identical among all technologies. However, this misses two key benefits of short lead time technologies; (1) the ability to delay costs leads to reduced net present value of those costs due to the discount rate, and (2) recourse response to alleviate stressed operating conditions can be much quicker and thus reduce operational costs the conditions will cause (e.g., higher production costs and/or increased load shedding costs).
5. Performance measure: A performance measure for a plan exposed to a single set of out-of-sample conditions is total cost which includes operational, investment and recourse. For a Monte Carlo based simulation, average costs, standard deviation, and worst-case costs are appropriate.
6. Computational Speed: The performance evaluation should be significantly faster than the CEP. This is because in the CEP, the years, blocks, and scenarios are coupled, to enable optimization across all of them. However, because performance evaluation is a simulation (and not a design process), this coupling is unnecessary. Elimination of this coupling allows for solution of much smaller problems and thus much lower compute time.

These concepts underlie a performance evaluation approach called the folding horizon simulation (FHS), first demonstrated in [49], and later extended in [24]. This approach should be further explored via three additional R&D directions. First, we observe that DMR, as described in Section 5, is in its implementation closely related to FHS. It is of interest to examine both approaches, focusing on the question of whether FHS can be used for design as well as performance evaluation. Second, how do we define and tune our validation methodologies such that they attain a proper balance of both rewarding building robustly for the future and reducing costs by only constructing the most critical assets? How do we determine what this balance should be in a way that is agnostic to the particular planning method used to generate the plan?

Finally, the interpretation of recourse should reasonably match how recourse would be achieved in reality. For example, if we are validating from the perspective of the "planner," then there is no inconsistency with discovering an issue at a particular time step, and then preemptively correcting the issue at a previous time step. However, if the validation takes the perspective of the "plan implementer," then a more realistic model for recourse would be to discover an issue at a particular time step and react to the issue in the following time step.

10. Conclusions

Driven by pressing environmental constraints, today, the way humans generate, transmit, distribute, and use electric energy is undergoing a worldwide transformation. Large centralized thermal generating stations connected at the high-voltage level are being displaced by wind, solar, and other distributed resources connected at both the high voltage and the lower voltage levels. Because the associated equipment is highly capital-intensive, equipment lives are very long, and the impact on economic competitiveness is so large, there is strong motivation to guide this transformation. CEP is the tool of choice to provide this guidance, because it enables identification of good decisions across resources and transmission, in terms of investments, investment portfolios, and policies, and how those decisions play out as the future unfolds.

This work investigates existing state-of-the-art methods and tools used to perform coordinated expansion planning (CEP). Additionally, it provides an R&D agenda that outlines what the authors believe are critical steps to advancing the maturity of these tools in areas that are extremely relevant to the issues presently faced by grid planners. Eight application areas are identified in this work which if further developed would vastly improve the state-of-the art CEP method in terms of the accuracy, flexibility, computation time, reliability, and cost effectiveness. These eight application areas include; (1) modernizing our market models, (2) four needs for additional modeling fidelity within the CEP, (3) representing uncertainty in expansion planning, (4) systematic ways to address computational complexity, (5) weather representation improvements, (6) improved consideration of resilience, (7) capturing the electric power systems interdependencies with other infrastructures, and (8) plan validation post optimization. These eight areas represent high value research areas which if adequately addressed will allow planners to successfully leverage present day computing resources to meet the future's most pressing grid planning issues through highly effective CEP software applications. Specific needs are addressed in each of these areas.

CRediT authorship contribution statement

P. Maloney: Writing - original draft, Writing - review & editing, Visualization. **P. Chitkara:** Writing - original draft, Writing - review & editing. **J. McCalley:** Writing - original draft, Writing - review & editing, Visualization. **B.F. Hobbs:** Writing - original draft, Writing - review & editing. **C.T.M. Clack:** Writing - original draft, Writing - review & editing. **M.A. Ortega-Vazquez:** Writing - original draft, Writing - review & editing. **A. Tuohy:** Writing - original draft, Writing - review & editing. **A. Gaikwad:** Writing - original draft, Writing - review & editing. **J. Roark:** Writing - original draft, Writing - review & editing.

Declaration of Competing Interest

The authors declare the following financial interests/personal relationships which may be considered as potential competing interests: Patrick Maloney - To the best of my knowledge there are no competing interests. Puneet Chitkara – no conflict of interest. James McCalley – no conflict of interest. Ben Hobbs – no conflict of interest. Christopher Clack - no conflict of interest. Miguel A. Ortega-Vazquez – no conflict of interest. Aidan Tuohy – no conflicts of interest. Anish Gaikwad – no conflict of interest. Joan Roark – no conflict of interest. To the best of my knowledge there are no competing interests.

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