TRANSFORMING ELECTRIC GENERATION PLANNING MODELS TO MEET SUSTAINABLE ENERGY POLICY GOALS

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I. Overview

Today’s electric power generation planning models and methods rely on decades-old practices of minimizing costs in order to optimize investment in new generation. These models make rough approximations that have been adequate in a world in which thermal generation was dispatched to meet forecast loads. However, as policies expand to incorporate multiple objectives, including the integration of intermittent renewable resources and targeted customer demand response, those models are rendered obsolete. Without modelling improvements, policy goals seeking to increase sustainable resource options may not be achieved cost effectively. There is a need to improve model formulations and industry practices to fully capture the need for, and benefits of, system flexibility in the face of short-run variations and forecast error, and long run policy, regulatory, technical, and economic uncertainties.

The paper explores what aspects of existing models need to be updated and the consequences of both maintaining the status quo and improving model capabilities. Current research into improved models is reviewed for best practices and challenges are identified. Recommendations are made on how to overcome the challenges in order to develop models that will better optimize mixes of renewable generation, thermal generation, demand response, storage, and transmission.

II. Introduction

Many countries have goals to reduce greenhouse gas emissions and boost energy security by reducing energy imports. Renewable energy is the prime means to achieve these goals. The European Union has a goal of 20% renewable energy by 2020 [1], while the renewable energy industry in Europe claims that 100% renewable energy is technologically achievable by 2050 [2]. China and India are striving towards goals of 15% by 2020. In the US, 37 of the 50 states have standards or goals ranging from 10% to 40% over varying time periods [3]. Key findings of NREL [4] suggest that it is feasible for the US to achieve 80% renewable energy by 2050; however, this theoretical feasibility has only been backed by comprehensive studies that integrate 30% wind energy [5, p. 19].

Renewable energy sources, especially the weather dependent resources of wind and solar that are abundant worldwide, have different characteristics than historical energy options. The Intergovernmental Panel on Climate Change recognized this in an elaborate report on renewable energy. Although significant challenges are recognized, the IPCC prematurely concludes that “there are few, if any, technical limits to the planned system integration of RE technologies…” [6, p. 612] Electric systems have not been stressed to these theoretical limits and those that have a higher penetration of intermittent resources, for example Denmark, rely heavily on interconnections with neighboring systems that do not have comparable intermittent resource levels. Achievability is questionable across all systems, as existing inherent system capability

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becomes committed and market rules fail to incentivize development of additional complementary resources. In part, antiquated modeling techniques are responsible for providing inaccurate signals for new investment, yet electricity market rules focusing heavily on competitive energy prices without considering the full line of system services that generators supply also are contributing to market inefficiencies. This is evident in Germany, where economic signals have led to plant shut downs and subsequent system capacity shortages. Also of note in Europe, is that its cleaner natural gas facilities are not economical while higher greenhouse gas emitting coal plants remain relatively more profitable [7]. As the electric system becomes more complex, markets must also become more complex to provide appropriate price signals in the market place.

Generation planning and investment models need to (1) provide answers to crucial questions facing planners, investors, and regulators for systems with ambitious renewable energy targets and (2) represent the features of power systems that are necessary to address those questions. Researchers have proposed planning model formulations that include some of these features, which have been incorporated in some commercial software packages, yet a fully integrative model that can be used for large systems and solved within a reasonable time frame still needs work.

As far back as 1882, when Edison electrified a small network in New York City, system operators have had to match generation with load. In those early days it was simple – shovel a pile of coal in the boiler and decrease the amount as the lights turned out. Weather was even an early factor necessitating the assistance of a spotter to see if clouds or a storm would require the generator to be stoked differently than required by normal weather. [8, p. 38] Generation expansion planning was also relatively straightforward with new generators being added as additional customers could afford the electricity. Electricity was an excludable public good delivered by a monopoly. Although profits from electricity were always the prime mover to growth, with limited technological advancement, access to electricity was more important than process efficiency. Customers, who could afford it, would pay whatever it cost because it allowed their business to move technologically forward.

Over the last 130 years, several transformations have occurred within the electricity industry: the movement from DC to AC allowing the transference of electricity over great distances and the development of much larger generators; the extension of power lines into remote rural areas of the United States in the 1930’s,2 providing a model of affordable electricity for all and moving closer to a pure non-excludable public good; the development of new sources of generation including mammoth investments in hydro, natural gas, and nuclear adding different system operating characteristics; the sophistication and sensitivity of electric consuming devices to the quality of power, making voltage and frequency control more important; and utility and market structures including competition with varying objective functions for cost minimization and profit maximization – generally selling the inelastic homogenous good called electricity. Today’s industry transformation revolves around achieving clean energy and energy security goals with renewable resources, while maintaining reliable load following operations introducing new aspects of product differentiation. Additionally, the long thought “too cheap to meter”

2 Promoted in part by FDR’s Rural Electrification Act of 1935
commodity of electricity is beginning to exhibit long suppressed price elasticity as customer demand response provides increasing system benefits depending on price signals.

As operations have become more complex, there has been increased need for tools with enhanced speed and complexity for conducting analysis. Even back in the late 1890’s Samuel Insull devised ways to track generator usage and load curves. He strove to increase utilization of his generators by finding compatible customer uses. [8, p. 68] Once electrification was more widespread, it became more common to match generators to loads, instead of visa versa; however, there were just a few types of generators that were either operated for baseload or for peaking. By the early 1960s it became evident that additional types of generation were needed to efficiently meet the load requirements. Hicks [9] provided theoretical insight into the optimization algorithms and types of units required – still using the load duration curve and screening curves at the core while Fitzpatrick and Gallagher [10] developed some of the first computer aided load duration optimization programs. Modern day texts for sustainable power systems still teach the fundamentals of these century old practices [11] as initial means for resource planning while industry software such as WASP3 and that from Ventyx4 use consolidated load curves over typical weeks. Although methods were developed to treat non-dispatchable resources as decision variables as far back as 1982 [12], this is not typically how industry planning is conducted. Missing in long-term planning models is accurate resource interdependencies and a means to capture aspects of real time operation - such as operating reserves (not to be confused with planning reserves), minimum operating levels and times, and ramp rates that are required within an hour to meet system reliability criteria and the resultant increased cost of maintenance due to cycling [13], [14], [15]; each of which may change the decision to optimize system resources through new investment as intermittent resources comprise increasingly higher portions of the total energy generated. A comprehensive review of renewable integration computer tools by Connolly et al. [16], confirms gaps in tools specifically for investment planning on a systems level with sufficient granularity.

The last 40-50 years have marked rapid technological increases in computational power, which impact the model complexity that can be employed for generation expansion planning. Yet, computation capabilities still limit the scope of modern analysis. By the 1970’s, dynamic programming methods were developed to incorporate reliability and uncertainty into generator expansion decisions that had previously been centered on cost [17]. Additionally, Anderson [18] discusses linear programming techniques utilizing the load duration curve but making the important caveat assumption that this modeling includes costs are not dependent on time. In the 1990’s, Hobbs [19] and Zhu and Chow [20] reviewed new optimization methods taking advantage of increasing computational power and including alternate resource options such as using demand side management or expanding the transmission system. Over the last decade, new optimization modeling techniques and extensions of veteran algorithms have been proposed by many researchers to capture the unique aspects of intermittent renewable integration including consideration of expanded operating issues to make investment decisions.

This paper summarizes the new types of questions that are being asked in generation investment planning, the model features that are needed to respond to those questions, and the state of the art

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of academic and commercial planning models. The existing literature is systematically reviewed and critiqued, including mathematical formulations and solution methods, and needs for new modelling developments and better data are identified. How the inclusion of significant quantities of renewable resources is changing system operations and why this is important to generation expansion planning is outlined in Section III. Section IV is a review of the current modelling trends for integrating intermittent wind and solar resources while Section V addresses both variability and uncertainty. Computational limitations in modelling and proposed techniques for modelling within given limitations are addressed in Section VI. Finally, Section VII presents some summary results and Section VIII provides concluding remarks for the direction of research efforts and improved models.

III. Intermittent Resource Operations

Wind and solar resources are variable and uncertain; intermittent and difficult to predict; yet the electric system must balance load and generation at all times and meet applicable industry operational standards. The usage of intermittent resources creates varying degrees of operational challenges. Although contributions to system demand may be relatively well predicted by probabilistic techniques and accurately portrayed in planning models (at least as accurately as other types of generators that include probabilistic forced outage rates), the inter-hour variability and regulation requirement impacts are not as easily ascertained and are system dependent. Ackermann et al. [5, p. 8] provides actual data in Denmark showing the need for ramping capability even at an hourly variation level. Reviews done by Smith et al. [21] and Strbac et al. [22] show that specific studies performed for systems can have a wide range of results. Further, Troy et al. [23] and Deane et al. [24] show that system costs are significantly underestimated using hourly instead of sub-hourly data and that ramp rate constraints are an important parameter to monitor. Ummels et al. [25] shows how unit commitment and dispatch are modified when data improvements are realized and that previous assessments provide faulty indications with respect to frequency regulation and operating reserves. Operational models for unit commitment and economic dispatch are being adapted to better predict actual operation with intermittent resources. Lotfi et al. [26] even suggest model improvements to handle complexities in optimization for systems without intermittent resources. Planning models for new investment lag behind optimization improvements in operations, yet the new investments being planned will be operated using revised dispatch and scheduling models. The challenge in updating the investment models is not adding every detail possible, but finding the relevant level of detail to make an accurately informed decision regarding tipping points between competing technologies.

Although, previous methods for determining system adequacy were based on yearly assessments of system peaks and available resources; continuing this practice with increased levels of variable resources will no longer insure adequacy throughout the year. The system may not have adequate flexibility to respond to intermittent resources in conjunction with demand variations hourly or sub-hourly or even have sufficient capacity in seasons that were previously of lesser importance. For example, summer peaking systems perceiving good from large solar investments may result in a net winter peaking system where solar capacity is ineffective at meeting peak consumer demand. Choosing the best long-term system resource investment requires a more robust characterization of the system then traditionally done as well as complete characterization of all forms of system flexibility.
Long-term resource planning models also lack the ability to predict system demand changes resulting from customer actions at varying price levels which could provide system flexibility to respond to intermittent resources. Historical average cost pricing passed on to consumers as “postage stamp” rates does not give electricity customers appropriate price signals to regulate usage or provide services back to the utility. In turn, electricity providers are not realizing the extent of customer alternatives that could be incorporated in long-term planning, especially in the context of meeting sustainability objectives.

Additionally, control schemes for intermittent resources should be considered as a source of flexibility, not just to curtail wind for over-capacity or congestion issues, but also to mitigate the need for additional reserves/system flexibility (over-regulation requirements). As curtailments increase in response to maintaining system reliability, the economic foundation will be laid for additional flexibility including some types of storage. Thus the full range of renewable energy characteristics needs to be incorporated in models for decision making.

An ideal investment planning model would incorporate all of the components shown below in Figure 1 for making a decision with available information.

![Figure 1: Necessary components of a generation investment model](image)

IV. Modeling Trends for Generation Expansion

Developing models to determine new generation investment includes defining the appropriate input variables and scenarios and selecting the best optimization model and algorithm. Long-term planning models have been derived from the tradeoff between scope and detail. The models should have sufficient detail to accurately solve the problem, yet not excessive detail that wastes human and computational resources. The generation selection problem needs to be only as accurate as needed to select the correct resource for investment and construction, and does not necessarily have to accurately account for all system costs and variations. The increasing reliance on variable generation and customer choice warrants the inclusion of new variables and changes to existing models. Grond et al. [27] explains some of the differences in varying power
system optimization models and their applications, including generation investment. Best practices in modeling include the elements depicted in Figure 1.

**Data of sufficient granularity:** It is essential that models be configured to take into account those variables that shape the decision at sufficient detail to accurately decide which type of new generation is best suited to the system. A majority of generation expansion models used in industry rely on non-sequential aggregated data for representative weeks or seasons. This approach, that averages typical load patterns, loses the expected variability experienced in actual operation. Combined with the variability and uncertainty in wind and solar output, existing models tend to smooth data instead of capturing the expected range of operating conditions or the correlations between data sources. This approach has worked when variation was low and within the range of the existing system generator operating characteristics; however, as operating limits are reached due to increased development of variable resources, the models no longer capture the necessary features for accurate decision making. New parameters and techniques are required.

**Sources of flexibility:** With rapid growth in renewable energy, it is necessary for generation system planners and investment analysts to capture the operational flexibility in their models so as to adequately capture the real-time cost of operation of the overall system especially for systems with limited existing flexibility [28], [29], [30]. As the penetration of variable resources increase, so does the need for flexibility such that existing models that may be sufficient to capture wind penetrations of 20% become ineffective at 40% - the exact amount of which varies greatly based on existing load and generation characteristics and that will be dependent on the resources that constitute the balance of system and the degree to which flexibility already exists.

Many studies consider wind curtailments as a means to reduce generation if there is excess generation in relation to load requirements; however, models should also consider the possibility of curtailments if insufficient ramping and reserves occur on the system. Generation expansion models should have the capability of weighing the decision between added investment cost for fast response units that are less efficient and correspondingly have higher impacts on the environment as compared with making smaller investments in slower response, more efficient units and curtailing wind if response constraints are exceeded. It is possible to increase overall renewable generation, reduce emissions and maintain reliability and security if wind curtailment is allowed for this purpose.

Liu and Jiang [31] overview technologies for mitigating intermittency. Some work has concentrated on utilizing one form of storage or another to provide system flexibility and mitigate wind generation variability [32], specifically hydro [33] [34], compressed air energy storage [35] or hydrogen [36]. Each of these is system dependent, but collectively show that it is necessary to model each decision option and in enough detail to develop an optimal plan. Other work has focused on consumer demand response [37], [38], [39], [40], [41] and its ability to contribute to system flexibility.

**Sequential modeling:** Some work has been initiated to track and incorporate flexibility in a sequential manner. Ma et al. [42] develops a construction and commitment algorithm using weighted representative weeks for each season which shortens computational complexity yet
captures seasonal energy and variation with unit commitment variables included. Since this model incorporates worst case seasonal variation, it may tend to overestimate the need for system flexibility. Further this model measures variability within a season but not between seasons. De Jonghe et al. [43] reviews the impacts of considering flexibility on the system and demonstrates that even hourly time steps in a sequential model yields different investment decisions when operating parameters are more accurately modeled. Shortt et al. [44] provide analysis on portfolio and cost differences when chronologically ordering the model data. Tracking sequential flexibility requirements needed for wind balancing and the inclusion of ramp rates along with other flexible generation sources such as wind curtailments, transmission and storage, lead to a significant change in the optimal investment mix of generation technologies, reducing slow ramp baseload technologies with faster ramp mid and peaking generators.

Cost of operations: It is becoming necessary to incorporate aspects of the unit commitment and economic dispatch models used for short term generation planning, so as not to miss important parameters in the long-term generation investment decision. Yet since the unit commitment model is computationally intensive to solve due to the high number of complex operating constraints, it is not feasible to include all of the details of 24-hour unit commitment in 20-year plus long-term investment planning. New modeling constraints such as startup/shutdown limits, minimum up/down time, and ramping constraints may play a larger role in the resource selection to meet operating reliability requirements. Growing renewable penetrations push thermal generators against their technical constraints which were not previously binding. Operating characteristics that were traditionally ignored in generation expansion planning models should form new constraints for analyzing the market with increased renewable generation. Palmintier and Webster [45] showed that just including sequential detail, without changing the time step, significantly changed the optimal capacity mix. Additionally, the ability of customers to provide alternative sources of system flexibility through demand response should also be considered.

It is becoming no longer sufficient to capture hourly dispatch and annual reserve margins. Future models will require the tracking of unused, yet ready resources to also insure that operating reserves are being met. It may also become necessary to have a variable operating reserve constraint instead of a fixed percentage included in the model, to account for changing system configurations and requirements throughout the year. New investment models will need to be able to capture not only the primary energy services provided by the generator but also all of the ancillary services including dispatch associated with transmission congestion and providing capacity for adequate supply. Including additional generation parameters is discussed by Krishnam et al. [46] using a multi-objective, long-term model with smaller and sequential time steps. Techniques used to accurately quantify the impact of increasing wind on an existing system, such as improvements to unit commitment and economic dispatch models, are also helpful in determining least cost generation expansion with wind included on the system. Kamalinia and Shahidehpour [47] suggest new model formulations to incorporate the additional constraints due to spinning reserves and ramp capability. Additionally, geographic diversity of wind is discussed. Generation expansion models should accurately include the variability of wind but also the diversity between various wind sources. High correlations of wind patterns will result in higher levels of ramping capability from the remaining system than wind facility with low correlations. Capturing the correlations and impacts to the balance of system can result in different system expansion investments.
V. Uncertainties

Most long term investment planning models are deterministic – the same least cost solution will always result for the given set of input parameters. Yet, there are many uncertainties in planning new generation resources for the subsequent 20-60 year period, even the next single year. Historically, the main uncertainties were load and fuel prices; however, additional uncertainties have included technological development, financial rates, new regulations, environmental sensitivities, etc. Intermittent generation adds the uncertainty of level of output, correlation with loads, and correlation with other intermittent sources. To account for uncertainties, stochastic approaches have been adopted instead of or in conjunction with deterministic models. Stochastic models are more complex in model formation, yet needed for planning proposes where uncertainty in the long-run is far greater than in the daily operations realm.

Uncertainty analysis can be carried out by incorporating in a single model, or part of a two stage process. One way renewable uncertainty can be incorporated in models is to add a flexibility requirement that tracks resource characteristics that will counterbalance the renewable uncertainty. Kirshen et al. [48] look at this flexibility requirement in the context of added wind development.

When implemented as a two-step process, scenario analysis to determine portfolios and uncertainty simulation to test chosen generation portfolios, the first deterministic step may miss the selection of certain portfolios that would have performed better during the stochastic simulations. Therefore, it may be important to incorporate some level of uncertainty, either through probabilistic methods or stochastic simulations, especially with regard to load and intermittent resource availability in the first step of portfolio identification.

Lotfi et al. [49] provide a probabilistic method for dealing with uncertainty while Xu and Zhuan [50] model wind uncertainty using chance constrained programming to determine an optimal amount of wind, given an existing system with operating constraints and reliability criteria. In this study, although the uncertainty in wind generation and system load are both considered, the correlation between the two is not, but should be included in ideal models. Even so, large variability in social cost is shown when the uncertainty is included in the model. This method would need to be expanded to include additional new investments for future year expansion.

VI. Modeling Limitations

Expanding already complex models stresses computational limits, but the good news is that unlike operational models that require solutions in a matter of minutes, investment models can be slower and consider a wider range of possibilities. After suggesting model parameter expanses, Kamalinia and Shahidehpour [47] also discuss computational impacts and suggest simplification techniques. Decomposition and parallel simulation are possible, but require more sophisticated tools and expertise [51]. De Jonghe et al. [43] states that adding operational considerations including ramp rates improves model performance; however, further inclusion of parameters such as minimum up and down times, would introduce binary variables and an MILP solution that would result in computational difficulties.
One method to reduce the number of variables added when including unit commitment parameters is to aggregate or cluster generating units, combining many binary variables of identical or similar units into fewer integer variables. Garcia-Gonzalez et al. [52] use aggregation in the context of joint bidding of hydro units and high wind penetration. Palmintier and Webster [53] extend the technique to natural gas units, providing results of a comparison of approaches including tradeoffs between accuracy and run time. Caution must be used with this approach such that the variables needed for the investment decision are adequately captured, including starts by unit type and redispatch required for transmission congestion.

Although resulting in enhanced speed, there have been accuracy tradeoffs, generally captured in overall cost. It is unclear from the analysis to date, whether the model reduction techniques result in less than optimal decisions. Increased analysis in this regard is needed. Perhaps these techniques will be most useful in model building insight and prescreening instead of revisions to the final model.

VII. Results

Based upon review of literature, the following are some observations about available and proposed models, and their responsiveness to the needs of users.

The operation and planning of systems with high penetrations of intermittent resources is uncharted ground. Although theoretical studies suggest that 80-100% renewable energy is possible, it is not necessarily economical or reliable. Detailed system operational and reliability studies have only been conducted to reach 30% intermittent renewable energy and many electric systems must rely predominantly on intermittent wind and solar resources to meet renewable energy goals. Without improved representations of how the electric system will be operated, the planning and investment models are limited in their ability to assess system performance under high intermittent renewable penetration. The broad brush methods used to advocate ambitious policy goals of 80-100% renewable resources are inadequate for capturing and evaluating system cost and reliability performance in the actual system. Existing models do not fully capture the variability and flexibility characteristics of traditional dispatchable generators, newer renewable resources and customer response alternatives – each of which impacts the overall portfolio of required resources to meet customer demand.

To improve models, it is necessary to rely on formulations that are more faithful to the detailed physical and economic characteristics of resources; use high quality data including interdependencies; and take advantage of increased computational power. Data improvements are needed particularly in assessing costs associate with thermal unit cycling and in determining price elasticity for customer response options. As data availability and use expand in some areas (such as incorporating unit commitment variables or transmission constraint), model approximations in other areas may be needed to provide computational solutions within reasonable time frames.

Existing models underestimate the operating cost implications of intermittent resources (and likely undervalue the contribution of customer demand response and wind curtailments). This is in part due to the subhourly need for system regulation to maintain frequency that is not captured in modelling, as well as inadequate representation of the need for ramping capabilities, increased
maintenance due to thermal unit cycling and the implications of wind and solar forecast errors. The cost of required incremental transmission reinforcements can also be underestimated.

Higher amounts of intermittent resources must be accompanied by an increase in system flexibility which needs to be sufficiently captured in modelling such that appropriate resource selection is accomplished. A spectrum of customer demand response is one potentially important source of flexibility, but is rarely represented realistically (in terms of cost and operating characteristics) in comprehensive planning models. Flexibility can also come from fast start, fast ramp, relatively small natural gas generating units; however, these are often the highest cost units and the simplistic modelling parameters neglect to capture their full benefits. Wind curtailments may be modeled in response to transmission congestion, but are rarely modeled as a potential means to reduce high cost frequency regulation.

Regulatory policies requiring least-cost additions may not choose necessary flexible resources as wind penetrations rise, because planning models that use representative system hours do not capture the necessary operating characteristics of fast ramping and actual repeated starts and stops. Incomplete systems of market pricing that rewards the lowest cost producers rather than flexibility may not result in additional flexible resources that have higher energy costs; for instance, markets with long averaging periods (one hour) will suppress within-hour price spikes that would reward resources that can respond to those signals with short notice. Possible market fixes based, for instance, on capacity payments for flexible capacity face difficulties in commensurating resources with very different operating characteristics (for instance, demand response limited to hot seasons and which can only be called on for short periods of time, versus peaking generation without operating hour limitations).

Although maximizing renewable energy output and minimizing system operating costs might seem to be consistent objectives, they actually can be competing, resulting in inefficient outcomes. Subsidized wind development, along with market price support or take-or-pay penalties, along with penalized fossil development can result in over-investment in variable renewable technologies because necessary system operating characteristics are disregarded. Investment decisions should consider the full range of operating services that a resource provides or requires; capturing the entire costs and benefits experienced on the system not just in primary energy markets. To the extent that energy production requires supporting ancillary services, these cost impacts should be factored into the decision to dispatch the offered resource which in-turn will influence the overall investment decisions. This is no more than accurately accounting for the true life-cycle cost of the investment including the system externalities.

VIII. Conclusions

The future of electric generation resource investment planning relies on clear policy and more realistic yet practical models that accurately capture the variables needed for optimal decision making. Without clear policy, the models will not optimize the right set of objectives and without improved models, the policy will not be achieved in a cost effective manner. The integration of a greater variety of weather and consumer-dependent resources requires more sophisticated modelling than currently exists. Generation and transmission parameters must be supplemented with weather forecasts and consumer behaviour models. Resource availability must also consider meteorological uncertainty and price elasticity of consumers, as well as their response to non-price incentives and cues. As the electric generation system transforms to
include a greater variety of resources, long-term planning models must also keep pace in modelling the necessary operating characteristics and inherent uncertainties of a wider diversity of resources.

As electric generation choices evolve away from traditional dispatchable thermal facilities, models for investment in new generation resources must also transition to incorporate the new system characteristics that are important to decision making. Industry models for long-term planning have not kept pace with operating models to include finer granularity in generator operating characteristic. Not only are the costs not adequately captured for the ramping and reserve requirements, but it is also uncertain that the models even result in a reliable system capable of meeting the potential operating conditions. Although it would be optimal to have one simple model to show investors and regulators that a particular investment decision is profitable or cost effective (depending on the party’s objective), this is likely not practical given increasing complexity generation technologies and system characteristics.

Existing models can be enhanced now to facilitate improved decision making. A great deal of research is being done on improving the modeling characteristics of thermal unit dispatch and best approximations should be incorporated into industry models. Minimal work has been done on the feedback of dispatch price on demand adjustments and renewable resource curtailment. The feedback of initial pricing information to make customer demand and renewable output adjustments is a needed source of flexibility to achieve higher renewable penetrations while maintaining system reliability as is the broader comprehensive model of all flexibility requirements and sources.

To improve sustainability, the energy system of tomorrow should not be bounded by the choices of today, but rather the choices of today should open possibilities for the future. In order to make the dramatic shift from a predominantly thermal based dispatchable system to one that derives 80% to 100% of its energy from renewable technologies with high penetrations of intermittent weather dependent resources, it is critical to implement long-term strategic planning and investment that leads to the success of the overall sustainability goals and accounts for the full interworking of the broader system.

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References


