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Temporal and spatial tradeoffs in power system modeling with assumptions about storage: An application of the POWER model

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A R T I C L E I N F O

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A B S T R A C T

As the number and complexity of power system planning models grows, understanding the impact of modeling choices on accuracy and computational requirements becomes increasingly important. This study examines empirically various temporal and spatial tradeoffs using the POWER planning model for scenarios of a highly renewable US system. First, the common temporal simplification of using a representative subset of hours from a full year of available hours is justified using a reduced form model. Accuracy losses are generally ≤6%, but storage is sensitive to the associated model modifications, highlighting the need for proper storage balancing constraints. Cost tradeoffs of various temporal and spatial adjustments are then quantified: four temporal resolutions (1- to 8-h-average time blocks); various representative day subset sizes (1 week–6 months); two spatial resolutions of site-by-site versus uniform fractional buildout across all solar and wind sites; and multiple spatial extents, ranging from California to the contiguous US. Most tradeoffs yield <15% cost differences, with the effect of geographic aggregation across increasing spatial extents producing the largest cost reduction of 14% and 42% for the western and contiguous US, respectively. These results can help power system modelers determine the most appropriate temporal and spatial treatment for their application.

1. Introduction

As the US electricity sector transforms to meet regulatory and reliability requirements in an aging and increasingly renewable system, numerous optimization studies are being conducted to explore the economic and power system impacts under different generator and transmission scenarios. These studies span a range of spatial scales, from regional, state, and balancing areas, e.g., PJM using the RREEOM model [1] and the Western US using the SWITCH model [2], to country-wide analyses, e.g., contiguous US using the ReEDS model [3], US-REGEN model [4], NEWS model [5], and POWER model [6]. Many of these studies utilize a specific multi-decade capacity expansion model or shorter-term planning model. Table 1 summarizes the relevant features of several US-based electricity sector planning models at the national scale (POWER, ReEDS, US-REGEN, NEWS, NEMS EMM, ReNOT) and at the regional scale (SWITCH, RREEOM). Each of these models deterministically optimizes for the least-cost system. A review of these model can be found in Section 4.1 of [7]; a broader review of optimization, simulation, and equilibrium capacity expansion models is provided in Ref. [8].

At a high level, the differences among these models can be characterized by tradeoffs in temporal resolution and extent, spatial resolution and extent, and model complexity. Temporal resolution is the time step size (hourly, sub-hourly, etc.); temporal extent is the time horizon over which the model solves (1 week, 1 month, 1 year, etc.); spatial resolution reflects the handling of the wind/solar/other devices included in the model (e.g., solve site-by-site, or solve as an aggregated unit across all sites/devices uniformly); and spatial extent is the geographic coverage of the model (state, region, country, etc.). System complexity refers to the representation of different power system components, such as resource adequacy, reliability, intra-regional transmission, distribution system impacts, variability and uncertainty of renewables, and storage chronology. These "levers" can be adjusted to suit the research objective(s) and computational resources available. For instance, temporal and spatial resolution can be reduced in order to capture a greater system complexity. Most models in Table 1 have adjusted the temporal lever to include a representative subset of hours or "time slices" across a full year due to computational limits.

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Table 1
High level comparison of selected US power system planning models. TS = time-slice. R&C = renewable and conventional. WECC=Western Electricity Coordinating Council. FERC=Federal Energy Regulatory Commission.

Model	Spatial resolution/Extent	Temporal resolution/Extent	Generator Technologies	Storage?	Transmission?	Source(s)
POWER (Stanford)	10 FERC regions; ~6000 wind and ~1400 PV and CSP sites; US	Hourly with 14 + TS/yr	Various R&C	Yes	Inter-regional	[6,7]
ReEDS (NREL)	134 load and PV resource regions; 356 wind and CSP resource regions; US	Hourly with 17 TS blocks/yr	Various R&C	Yes	Inter- & intra-regional	[9]
SWITCH (UC Berkeley)	50 load regions; ~3000 sites each wind, PV, and CSP; WECC	Hourly with 144 TS per 10-yr investment period (576 h total)	Various R&C	Yes	Inter-regional	[2,10]
RREEOM (UDel)	PJM region	Hourly over 4 yrs	Various R&C	Yes	No	[1]
US-REGEN (EPRI)	15 regions; US	Hourly with 86 TS/yr	Various R&C	No	Inter-regional	[4,11]
NEWS (CIRES)	256 load regions; ~37,000 wind and/or solar sites; US	Hourly for 3 yrs	Various R&C	Yes	Inter-regional	[5]
NEMS EMM (EIA)	22 regions, US	Hourly with 9 TS blocks/yr for 20–25 yrs	Various R&C	Yes	Inter-regional	[12]
ReNOT (Northrop Grumman)	Gridded cells (4 km solar, 12 km wind), US	15 min solar, hourly wind	Wind & solar	No	No	[13,14]

Understanding the tradeoffs in model design can help both model builders and model users select the most appropriate combination of model parameters for their given application.

The objective of this empirical study is to quantify the tradeoffs in accuracy and computational requirements associated with the spatial and temporal modeling decision levers, which are particularly important for large-scale power system planning models. The POWER model – **P**ower system **O**ptimization **W**ith diverse **E**nergy **R**esources [6] – is used to examine these sensitivities. The complexity lever of POWER is fixed for all cases here, except where (1) the temporal treatment affects the storage formulation (Section 3.2.2) and (2) a reduced form of POWER is used to examine a fuller temporal extent (Section 3.2.3). The complexity state in the default POWER formulation includes the deployment and hourly operation of each dispatchable generator technology, storage technology, and transmission line within each representative day; variability of wind and solar generators based on hourly wind and solar resource potential data across thousands of sites; operational considerations for dispatchable generators in the form of ramp rate and minimum load limits; planned and forced outage rates; chronological storage treatment within each representative day across multiple storage technology options; inter-regional transmission network connecting 10 regions across the contiguous US; renewable portfolio standard (RPS) targets; generator outage rates; emissions tracking; and a statistical formulation for operating reserves including contingency, frequency regulation, and forecast error reserve requirements. POWER does not include fuel supply curves, intra-regional transmission lines, distribution system impacts (e.g., voltage deviations), or electricity market factors (i.e., market rules and products), and it does not make investment decisions with foresight of future policy or economic factors. An explicit planning reserve is also not included, though the load balance constraint serves as a proxy for ensuring resource adequacy across the model time horizon.

The impacts from three main sets of scenarios are assessed: (1) model simplifications and justification due to a reduced temporal resolution, (2) spatial extent and temporal size (as reflected by various representative day subset sizes) cost tradeoffs, and (3) temporal and spatial resolution cost tradeoffs. For each scenario, various RPS target levels are evaluated, ranging from 40% to 100%, and three spatial areas are considered: AllCA (California), Western Electricity Coordinating Council (WECC, comprised of AllCA, SW, and NW regions in the US), and the contiguous US. The results presented here focus on the higher RPS levels since actual power systems, and consequently the capacity expansion models that analyze them, are moving toward higher penetrations of renewable resources.

While computational power and data quality are improving, enabling planning models to incorporate greater detail, there remains a general lack of understanding of the sensitivity and consequences of various model adjustments. The only similar work of its kind to date to our knowledge is Mai et al. [15] and Barrows [16], which provide a systematic comparison of the impact of various capacity expansion modeling configurations and details on investment decisions and run time using the RPM model for the Western US. Other studies have examined a single aspect of the temporal treatment of capacity expansion models, such as in Ref. [17] with a new day selection method using a model of the European power system. This paper contributes to the same research area by mapping out a more extensive tradeoff space between temporal and spatial capacity expansion model components using the POWER model of the contiguous US, with additional foci on storage attributes and highly renewable electricity futures.

The purpose of this paper is not to declare technology winners and losers. Rather, the quantitative and qualitative trends from these results can help power system modelers determine the most appropriate treatment of temporal and spatial components for their application, as well as gain a better understanding of the corresponding tradeoffs in accuracy and computational requirements. This study's systematic comparison of temporal and spatial modeling tradeoffs provides a valuable contribution to the limited existing work in the literature as applied to capacity expansion modeling. However, this work does not capture the current research trend to include all energy sectors and/or novel technologies for greater system efficiency, flexibility, and synergies. Therefore, the results are likely only applicable to the narrow field of capacity expansion modeling for the electricity sector under the model assumptions embedded within the POWER model.

2. Brief model description

POWER consists of models of generator technologies (baseload, dispatchable, and variable), storage technologies, and a transmission network, with a statistical characterization of operating reserves. The model encompasses the ten Federal Energy Regulatory (FERC) regions in the contiguous US [18] (note that the FERC region CAISO is replaced with a modified full-California region called "AllCA"). POWER uses a full year of hourly wind and solar data across thousands of sites from 2006, historical hourly load data from 2006 by FERC region, other regional renewable resource