***IMPACT OF MODEL RESOLUTION ON SCENARIO OUTCOMES FOR ELECTRICITY SECTOR SYSTEM EXPANSION***

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## Overview

Power sector capacity expansion models (CEMs) are often used to evaluate impacts of technological, economic and policy drivers on the cost-optimal generation capacity mix and their utilization in reliably meeting electricity demand over decadal time scales. Rather than modeling and optimizing power grid operations at a high temporal resolution (e.g hourly) while evaluating new capacity investments, which is computationally expensive, most commonly used CEMs [1] make several approximations to represent grid operations. Consequently, the generation capacity mix projections of these CEMs does not immediately guarantee feasible operating conditions, and often need to be heuristically adjusted to arrive at a feasible solution. Moreover, the temporal resolution of a CEM is particularly important when evaluating scenarios with high levels of generation from variable renewable energy sources like wind and solar. Here, we investigate the impact of embedding additional operational detail in a CEM framework on the resulting projections for generation capacity additions and their utilization. Studying a range of scenarios for the Texas grid, we find that, in general, a traditional CEM using aggregated time blocks [1], estimates greater solar photovoltaic (PV) capacity additions and lesser wind and natural gas (NG) capacity compared to an alternate CEM with chronological time-representation of grid operations. Moreover, this “chronological” CEM (C-CEM) framework better approximates the annual generation mix and estimates lower unmet demand, when evaluated via hourly grid operations simulations for multiple realizations of load and renewables generation. The findings imply the need for sufficient temporal resolution and chronology, or surrogate model constraints that yield similar behaviour [2], to be considered in power sector CEMs and more broadly multi-sector energy-economic models.

## Methods

We develop and systematically compare outputs from a “chronological” CEM (C-CEM), which models annual grid operations using up to 12 representative days (288 hours), with outputs from a commonly used “time slice” CEM (TS-CEM), using aggregated time blocks for a range of scenarios for the Texas grid. Both models are least-cost optimization models with perfect foresight that minimize total discounted cost over a 30-year planning horizon. The total discounted cost objective includes investment costs for new capacity additions, costs to extend the lifetime of existing capacity, operating costs (fixed and variable), fuel costs and generator start-up costs (C-CEM only).

Temporally, the C-CEM represents annual load, as well as wind and solar generation using 12 representative days at an hourly time resolution, whereas the TS-CEM represents annual load, as well as wind and solar generation, with 16 time slices representing different times of day and seasons. In other words, the TS-CEM averages load and renewables capacity factor data in each of the four seasons (summer, fall, winter, spring) into time slices representing morning (7 am -2 pm), afternoon (2-6 pm), evening (6-11 pm), and night (11 pm -7 am) [1]. With the exception of minimum turndown constraints for coal and nuclear generators, which set the minimum operating level for thermal generators as function of their peak seasonal output [1], the TS-CEM does not link two consecutive time slices with respect to operational constraints.

The C-CEM considers important details associated with thermal generators including: unit commitment decisions (i.e. commitment of generators to meet load), hourly ramping constraints, spinning reserves, quick-start reserves, and start-up costs. In contrast, the TS-CEM omits these details, although spinning reserves are partially taken into account. Lastly, because the C-CEM includes unit commitment decisions, thermal generation expansion decisions are modeled as integer decisions, unlike the TS-CEM which allows for a fractional number of thermal generators to be built.

## Results

We systematically compared the capacity projections of the two CEMs over a range of hypothetical scenarios for the Texas grid, wherein both models were constrained to meet a certain fraction (40%-70%) of load in 2040 (and beyond) with renewables generation while utilizing a consistent set of assumptions about other inputs (e.g. NG fuel prices, technology costs). The results suggest that TS-CEM shows a strong preference for solar PV installations over wind and NG capacity compared to the C-CEM across most of the scenarios considered here. For instance, in the 40% renewable energy scenario using EIA AEO 2016 reference scenario gas price assumption [3], the TS-CEM projects 35% higher solar PV capacity by 2045 compared to the projections of the C-CEM. Further, these differences between the outputs of the two CEMs are found to be robust to changing input assumptions on: 1) NG fuel price, 2) solar PV capital costs and 3) annual capacity installation limits for each technology.

We also tested the robustness of the grid operations approximations made by both CEMs by evaluating their projected capacity mix through a production cost model, which simulates annual grid operations at an hourly resolution. Here, we account for the prevailing intra-annual and inter-annual variability of load and renewables generation observed during grid operations. Our findings suggest that the capacity mix projected by the C-CEM framework better approximates the annual generation mix and results in lower unserved load compared to the capacity mix projected by TS-CEM.

## Conclusions

This study demonstrates how the choice of model representation of grid operations within a power system CEM framework can impact the resulting outputs, namely the projected capacity mix, generator utilization and the likelihood of unserved load. For the same set of technology and cost assumptions, a traditional CEM with time-slice representation of grid operations (e.g. TS-CEM) is observed to overestate solar PV capacity and understate wind and NG capacity deployments compared to a CEM with higher temporal resolution and generator ramping and startup constraints (e.g. C-CEM). The differences in the capacity mix to achieve the same renewables penetration targets has reliability implications as reflected by the lower unmet demand projected for the C-CEM capacity mix when tested in a detailed hourly simulation of annual grid operations. These findings are relevant to the broader energy systems modelling community beyond power systems, since variants of the time-slice approach are often used to represent power sector operations in multi-sector energy-economic models (NEMS [2,3]) and integrated assessment modelling. The findings of this analysis indicate the need to improve the accuracy of representing variability of load and renewables generation profiles in these models as well, by either using a representative days approach to model grid operations or other parametric approaches that yield similar outcomes.

## References

1. National Renewable Energy Laboratory, "Regional Energy Deployment System (ReEDS)," National Renewable Energy Laboratory, Golden, CO, 2011.

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3. Energy Information Administration, "Annual Energy Outlook 2016: with projections to 2040," U.S. Energy Information Administration, Washington, DC, 2016.