Michael Craig

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RIPS Transfer Information to Francisco

This document provides an overview of the work I’ve accomplished to date on the RIPS project, details where my work can be found, and lists work that needs to be done. Before beginning this document, please read the RIPS Documentation file for a general overview of how this work fits into the broader project.

**Project Overview**

My work has focused on developing two power system optimization models: a capacity expansion (CE) and unit commitment and economic dispatch (UCED) model. The figure below provides a general schematic for how these two models interact. In general, the CE model forecasts generator additions and retirements over time. At a certain point in the future – likely around 2050 – the UCED model then determines detailed operations of the future generator fleet.

The challenge of the RIPS project is how to include the effect of future climate conditions on generator expansion and operations. My approach thus far has been to account for them in both models. In the CE model, generator additions and retirements depend on the ability of generators to contribute to meeting demand at least cost, which can be impacted by generator curtailments due to future ambient conditions under climate change. In particular, the impacts of climate may vary across time (climate-induced curtailments will vary across days and hours for a given generator), space (plants in Alabama may be harder hit than in North Carolina, for instance), and plant type (coal plants may be more susceptible than gas plants). The CE model tries to capture all these effects. The same effects also pertain to the UCED model; climate-induced capacity and efficiency reductions will vary across generators, space, and time. Thus, the UCED model accounts for the same effects as the CE model.

I have been thinking about climate-induced reductions of generator capacity as falling into two buckets: capacity deratings due to ambient conditions and capacity curtailments due to regulatory limits on thermal discharges to bodies of water. While we originally were going to consider efficiency reductions, Aviva’s work has found these to be minimal, so I have not accounted for efficiency reductions yet. (Doing so would require making heat rates in the CE and UCED models vary by hour.) With respect to capacity deratings, Aviva is wrapping up her work on those regressions. I have Python code that estimated reductions based on an older work product from Aviva, so there is a placeholder in the code for capacity deratings. You will need to update the form and coefficients of these regressions with data from Aviva.

With respect to the latter, states regulate thermal discharges from power plants to protect water quality. (I have downloaded several of these permits at ClimateWaterAndPowSys/ThermalDischargePermits.) In general, these permits limit the water temperature or temperature increase of the *body of water* into which a power plant discharges heat. So, if a power plant sits on a river, the permits limit the temperature of the river to, typically, 32 C. Thus, as stream temperatures increase, thermal discharges from power plants may trip regulatory limits more, resulting in capacity curtailments. To estimate these curtailments, I’ve developed a series of equations in the document titled ‘CurtailmentEquations\_Craig\_16Aug17’ (in the ClimateWaterAndPowSys folder). As that document makes clear, the equations I’ve developed represent real-world regulations significantly better than equations used in past papers.

The above models, in addition to factoring in climate-induced curtailments, also account for the effect of climate on demand through Francisco’s regressions and for changes in hydropower generation using data from PNNL. With respect to hydropower generation, PNNL provides monthly energy availability by hydropower facility. Ideally, the CE model can be run for a representative month per season, allowing for monthly energy availiability for each hydro unit to be input directly to the CE model. The UCED model, though, only runs for a 24- or 48-hour horizon, so monthly data needs to be decomposed to the daily time step. For that, I’ve started developing a mid-term hydro-thermal coordination model. (This is a standard power system optimization model. Usually, these models account for stochastic water inflows, but thankfully PNNL has already done that work for us.) This hydro model would run before the UCED model to determine daily hydropower energy availability, which is then passed into the UCED model.

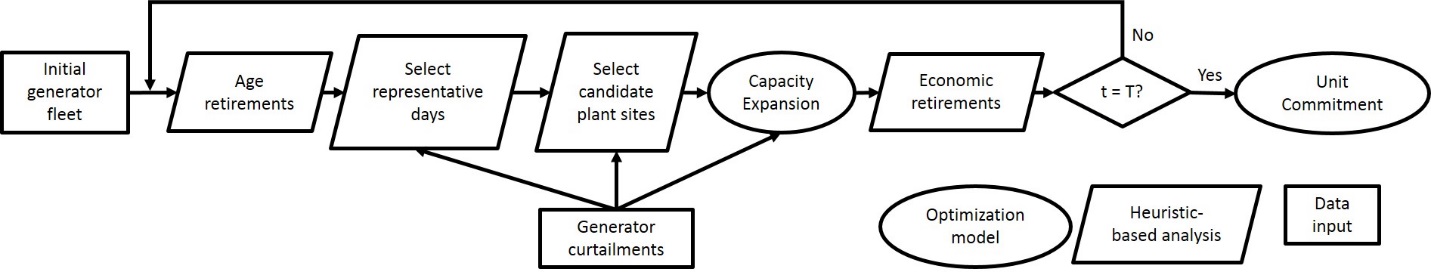


Figure: Proposed modeling approach to estimate the effect of climate change-induced efficiency and capacity reductions on power system planning and operations. “Unit Commitment” refers to a unit commitment and economic dispatch model.

**Current State of Power System Optimization Models**

The RIPSDocumentation\_Craig\_10Nov17 provides a slightly outdated description and formulation of the CE and UCED models. The document is outdated in that new features have been added, rather than features have been eliminated.

*CE Model*

The CE model (CERIPS24July2017PS.gms) is largely complete, but will need to be debugged, as I was unable to fully run it without data from other groups. The CE model minimizes fixed and variable costs. Fixed costs are annualized capital and fixed O&M costs for each plant type. Plant types for new construction are divided into renewable plant types, thermal plant types that can be curtailed, and thermal plant types that can’t be curtailed. Operational costs equal the costs of generating electricity to meet demand.

The CE model requires hourly electricity generation meet demand, and that sufficient capacity exists to meet a planning reserve margin. The CE model is a zonal model, so generators and demand are divided into zones and transmission between zones is modeled simply as electricity flows without DC or AC power flow considerations (similar to http://www.sciencedirect.com/science/article/pii/S0140988316302638). The CE model is also divided into cells (which are mapped to zones). These cells correspond to the cells from UW’s hydrological model. Thus, each cell has different meteorological and hydrological inputs, which in turn means power plants sited in different cells experience different curtailments due to climate change. Thus, the CE model not only optimizes for construction of generators between plant types, but also across cells (or space).

The CE model also includes pumped hydro units (note that you may want to remove these for computational efficiency), so electricity generation must account for charging of pumped hydro units.

The number of generators can be built of each plant type is limited by some number set sufficiently high to not actually limit deployment. Generation by new and existing plants that can be curtailed is limited by an hourly time series of capacities that account for curtailment. Renewables are also limited by an hourly capacity profile based on wind and solar generation data. As discussed above, hydropower units are limited based on energy availability received from PNNL. Finally, the CE model accounts for CO2 emissions so can model a carbon cap.

The Python code for processing inputs to and outputs from the CE model is largely complete, although some debugging may be necessary. Additions or modifications to the Python code for the CE model you’ll need to make are:

* Solar data currently comes from the NREL Solar Integration Dataset. However, Bri recommends we instead use NSRDB data, which provides solar irradiance, then use that data to estimate PV generation. I have downloaded NSRDB data at points in a grid over the entire region (Databases\NSRDBRIPS). In the SolarMOEPaper folder, there are Python scripts for inputting NSRDB data to PVLib to get estimated hourly generation.
  + GetRenewableCFs script
* Right now, the Python code has placeholder code to insert Aviva’s regressions that link capacity deratings (NOT related to regulatory limits) to ambient conditions. You will need to update the form and coefficients in these regressions and the mapping of plants to regressions.
  + CurtailmentRegressions script
* The code loads meteorological data at the regional rather than cell-specific data. If you do use regressions from Aviva, you will need to use cell-specific meteorological data from UW.
  + ModifyGeneratorCapacity script, loadMetData function
* The CE model currently uses Francisco’s demand forecast for TVA. That code should be updated for the Southeast when regressions are available.
  + ForecastDemandWithRegression
* The CE model has a “specialh” set of hours, which is currently used to include hours from the day with peak demand. However, you may also want to include days with peak curtailment of generators. If so, then you will need to add a set of hours for these peak curtailment hours. I did not because the day with peak demand may very well overlap with the day with peak curtailment.
  + DemandFuncsCE script, selectWeeksForExpansion function (also will require modifications to GAMS code)
* You’ll need to finish implementing the curtailment equations, which use a simple mixing formula, from the CurtailmentEquations document. The environmental regulation equation currently includes water flow (availability), but I have not loaded that availability data in the RIPSMasterScript yet.
  + For loading water availability data: ModifyGeneratorCapacityWithWaterTData script, loadWaterAndMetData function
  + For including availability in curtailments: CurtailmentFromEnviroRegs script, setEnvRegCurtailments function
* TWEAKS/CHECKS ONCE CE MODEL IS RUNNING:
  + How quickly the CE model runs will partly determine how many days you can include in it. If you include many, then how I currently handle max generation in each set of days by each hydro plant is OK.
  + You should revisit special days that are included in the CE model, and think of other possible interesting days to examine. For these days, you’ll have to figure out how you want to set maximum hydropower generation on those days.
  + I did not observe charging by the pumped hydro units in the CE model. I’m not sure if this is a bug or if there was never a reason for them to, so I would check that later after adding the features above. Like I said, pumped hydro will add significant computational burden, so you may end up eliminating it.
* LOW PRIORITY ITEM:
  + Wind generation data right now comes from the WIND dataset. I chose 2009 generation data because it has a moderate average CF, but you may want to select a different year. If there’s a TMY in the WIND data, that would be the best route (you can ask Bri this). [LOW PRIORITY]

*UCED Model*

Once you understand and have the CE model running, you have everything you need to create the UCED model. Right now, the UCED model is a standard UCED model with zonal transmission limits. As such, it has none of the features or constraints from the CE model related to curtailment or other climate change impacts. However, those curtailments and impacts will use the same Python functions and be structured the same in the UCED model as in the CE model, so porting them over should be straightforward.

The UCED model differs from the CE model in that it has three operational reserve classes – contingency, flexibility, and regulation up. For a discussion of these reserve classes and how they’re calculated, see http://iopscience.iop.org/article/10.1088/1748-9326/aa9a78.

*Mid-term Coordination Model*

I have not started the Python code for the mid-term hydro-thermal coordination model. However, all the code you will need for this can be found in the CE model, so you will just need to port code over. The coordination model should conduct a simple economic dispatch model for an entire month. In the coordination model, hydro plants should have monthly max generation provided by PNNL. By dispatching these models, the coordination model will tell you how much each hydro plant generates daily, which you can use to set a limit on daily generation & then feed that into the UCED model.

**Challenges**

There are several challenges with model design and application that you will need to resolve based on data you received. First is over what time period you will run each model, but particularly the UCED model. Depending on the problem size, the UCED model could take a day or more to solve for 1 year. Thus, how you account for inter- and intra-GCM uncertainty with the UCED model will be a challenge. One option, for instance, would be to run the UCED model from 2045-2055 for several GCMs and compare results within and between GCMs.

Another challenge will be exploring how much signal versus noise there is in forecasting generator fleets to 2050. The climate signal could be strong and significantly affect investment decisions, or it could be weak and be washed out by other uncertain variables. Note that to improve computational efficiency of the CE and UCED models, I add a very small amount to operational costs of power plants to ensure they all have different costs. If the climate signal is virtually zero, then this tiny adder could affect decisions even more than the climate signal!

**Directory Guide**

(Item : Location)

Code: EPP Research / PythonRIPSProject

Data: EPP Research / Databases [for location of specific datasets, see directories in code files]

Literature review: EPP Research / ClimWaterAndPowSys

Incomplete preliminary paper draft: EPP Research / RIPSDocumentation\_Craig\_10Nov17

Equations for handling thermal curtailment of power plants: EPP Research / ClimWaterAndPowSys / CurtailmentEquations\_Craig\_16Aug17.docx

Data from UW: https://drive.google.com/drive/folders/0AOupxt4ulZXjUk9PVA (ask Yifan to invite you to folder if you don’t already have access)

**Work done since 11/17/17**

Created script to download NSRDB data for RIPS + started downloads (NSRDBRIPS in Databases)