Scalable Stochastic Transmission Expansion: A Use Case for ExaSGD

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EXASCALE COMPUTING PROJECT

Introduction

Power systems which have large amounts of intermittent generation are prone to congestion, renewable curtailment, and loss of load[1]. To prevent such adverse events, transmission networks must be strengthened appropriately to serve increasing load and evolving generation profiles with variable and uncertain generation. To effectively compute transmission network improvements, a model should contain a sufficiently detailed representation of operations to guide decision making.

The ExaSGD program is developing an extreme-scale solver for stochastic security constrained AC optimal power flow problems on large power grids. While the critical path of the program is the frequency response and recovery problem, core solver capabilities enable infrastructure planning using high-fidelity stochastic operational models. Such capabilities are precisely those required for transmission expansion planning for future power grids.

We present a three-stage stochastic programming model capable of utilizing the full computational potential of ExaSGD to inform transmission planning of power systems with high penetrations of intermittent generation resources.

Model Formulation

Variable	Stage	Description
x	First	Transmission Expansion Decisions
y	Second	Thermal Generator Setpoins
z	Third	Loss of Load
η	Second	Possible Hour of System Operations (determines load)
ξ	Third	Possible Available Wind Power for an Hour

Table 1: Variables of Three-Stage Stochastic Program.

Our model is a three-stage stochastic program:

$$\begin{aligned} \min \quad & c(x) + E_{\eta}\left[o(x,\eta) + E_{\xi|\eta}\left[h(x,\eta,\xi)\right]\right] \\ \text{subject to} \quad & x \in \mathcal{X}, \end{aligned}$$

where

$$o(x,\eta) + E_{\xi|\eta}\left[h(x,\eta,\xi)\right]$$

is defined as the minimization of the following problem

$$\begin{aligned} \min \quad & \tilde{o}(x,y,\eta) + E_{\xi|\eta}\left[\tilde{h}(x,y,\eta,\xi)\right] \\ \text{subject to} \quad & y \in \mathcal{Y}(x,\eta), \end{aligned}$$

where the constraints capture generator ramping constraints. Similarly,

$$\tilde{h}(x,y,\eta,\xi)$$

is defined as the minimization of the following problem

$$\begin{aligned} \min \quad & r(x,y,z,\eta,\xi) \\ \text{subject to} \quad & z \in \mathcal{Z}(x,y,\eta,\xi). \end{aligned}$$

where and the constraints are the standard DCOPF power balance and line flow constraints. All variables are described in Table 1. Figure 1 gives a visual representation of this problem. The variables η and ξ capture the temporal and wind uncertainty, respectively. The two expectation terms are both approximated with a sample average which requires selection of scenarios.

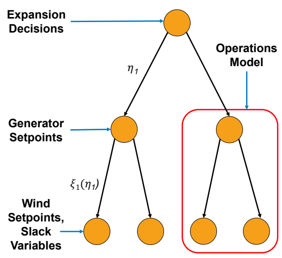

Figure 1: Three-Stage Stochastic Program Formulation.

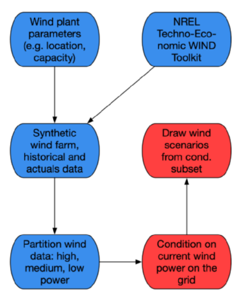

Figure 2: Scenario Selection Process. Blue represents preprocessing while red represents repeated steps for each second stage node. This data driven approach preserves spatiotemporal correlations present in the WTK data.

Scenario Selection

To produce the scenario set, we sample hours from the 8760 hours in a year. Hours selected are then mapped to historical load data at 5-minute resolution. Thus each hour selected includes a 12-period load time series at each transmission bus.

High-fidelity wind power scenarios and actuals are created as depicted by Figure 2. The basis for the samples is NREL WIND Toolkit (WTK)[3]. Our approach to scenario generation enables the use of multi-period wind power scenarios for geographically distributed wind farms while preserving high-fidelity spatiotemporal relationships present in the WTK data. Figure 3 depicts 10 scenarios of total wind power on the grid. Figure 4 shows an example of a scenario for each of the 22 wind farms.

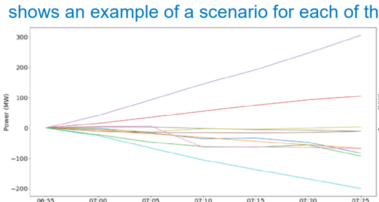

Figure 3: 10 Total Wind Power Scenarios. These are 6 steps at 5-minute resolution. Scenarios are given as deviations from persistence. Significant changes in wind power can occur across the entire grid.

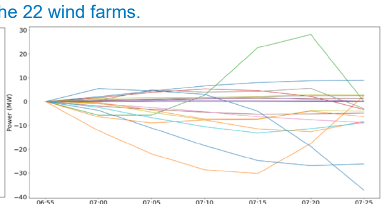

Figure 4: Wind Power Scenario for Each of the 22 Wind Farms. These are 6 steps at 5-minute resolution. Scenarios are given as deviations from persistence. Significant changes in wind power can occur even for a single wind farm over 30 minutes.

Results

In order to test our approach, we used a modified version of the RTS-GMLC[4]. The system was modified by converting all solar generation into wind generation and dropping all hydro generation. Furthermore, we reduced the maximum line flow limit by 25% and increased the load by 25%. These last two changes were made to make the system more amenable to expansion and to account for future load growth.

Branch	Initial (MW)	Model	Expand (%)	Expand (MW)	Final (MW)
A27	375	2 Stage	17.383	65.186	440.186
		3 Stage	15.508	58.156	433.156
C2	131.25	2 Stage	0.098	0.128	131.378
		3 Stage	2.103	2.760	134.010
C29	375	2 Stage	29.213	109.548	484.548
		3 Stage	38.499	144.370	519.370
C6	131.25	2 Stage	22.883	30.034	161.284
		3 Stage	35.567	46.682	177.932

Table 2: Results of Two- and Three-Stage Model. The three-stage model consistently expands lines by a larger amount than the two-stage model.

We chose 16 representative hours from a year to capture load uncertainty: 3:00-4:00, 11:00-12:00, 18:00-19:00 and 23:00-00:00 from the 5th of January, April, July and October. We chose these dates to reflect the load variability in a year and to capture a variety of wind conditions. To represent the wind uncertainty, for each of the above times, we selected 20 wind scenarios giving us a total of 320 scenarios.

To construct the models, we used the NREL developed packages PowerSimulations.jl[5] and PowerSystems.jl[6]. To solve the problem, we used ProgressiveHedging.jl, a Julia implementation of the progressive hedging (PH) algorithm[7], and the commercial solver Xpress.

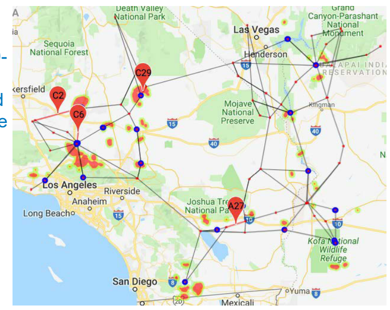

Figure 5: Map of the RTS-GMLC Network. 73 buses (red dots), 22 wind-generating buses (blue circles), 445 WTK wind sites (heat map), 104 transmission lines (black lines), and 4 expansion decisions (red lines)

For comparison, we also ran the two-stage formulation of the expansion problem where load and wind variability were handled simultaneously. This problem is constructed by taking a single realization of the wind for each of the 16 times considered in the three-stage model. The results are given in Table 2 and visualized in Figure 5.

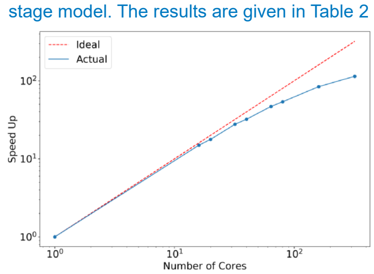

Figure 6: Strong Speed Up of Progressive Hedging. All runs were conduct on Eagle. IPOPT with HSL linear solver MA57 was used for the PH subproblem solution.

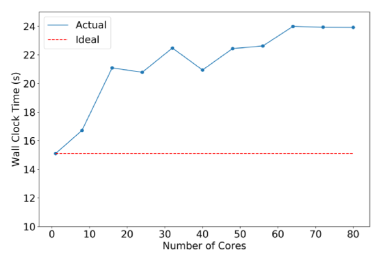

Figure 7: Weak Scaling of Progressive Hedging. All runs conducted on Eagle. IPOPT with HSL linear solver MA57 was used to solve subproblems. Wall clock time gives the average time for a PH iteration. Each core solved four subproblems.

Scalability

We conducted computational experiments to assess the weak and strong scaling properties of ProgressiveHedging.jl. To do this, we disabled all parallelism in the subproblems which were solved using IPOPT[8] with the HSL linear solver MA57[9]. These are place holders for ExaSGD software currently under development. Results depicted in Figures 6 and 7 illustrate strong and weak scaling. Using the ExaSGD solver for the subproblems should significantly improve the scalability.

Future Work

Future work consists of decomposing the problem into two two-stage problems and integrating ExaSGD software. This enables exploring the effects of a higher fidelity operational model (e.g. security constrained ACOPF) on expansion decisions. Furthermore, this integration will enable new types of transmission expansion studies based on high-fidelity modeling not included in established methodologies, e.g. frequency response and recovery, cyber security events, or natural disasters.

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