Analysis of the FY20 Budget with Modifications to the GenTrader Model Inputs

--- October 31, 2019 ---

BACKGROUND

In this analysis, multiple GenTrader scenarios were modeled to examine the impact of varying transmission constraints and unit dispatches. All scenarios analyzed were compared to the Base Case of the FY20 Budget to measure those impacts.

OVERVIEW OF MODEL ASSUMPTIONS

Base Case:

1. FY20 budget. Deerhaven Renewable is modeled as Must-run during the summer. Deerhaven Unit 2 is modeled as Must-run when available. All other generators are economically dispatched.

Scenarios:

1. **Re-run the FY20 budget run without generator limitations**. Meaning, no units are modeled as must-run and all units are economically dispatched when available. Import limits are maintained as the same limits in the budget run (25 MW when Deerhaven 2 is available, 50 MW when Deerhaven 2 is unavailable).

2. **Re-run FY20 budget with all the market import limits removed** (448 MW max capability). No units are modeled as must-run and all units are economically dispatched when available. No spinning reserves are modeled.

3. **Re-run FY20 budget with all the market import limits removed** (448 MW max capability) **and DHR and CC1 Must-Run**. Deerhaven Renewable and JRK CC1 are modeled as must-run when available. All other units are economically dispatched when available. No spinning reserves were modeled.

RELIABILITY LIMITATIONS

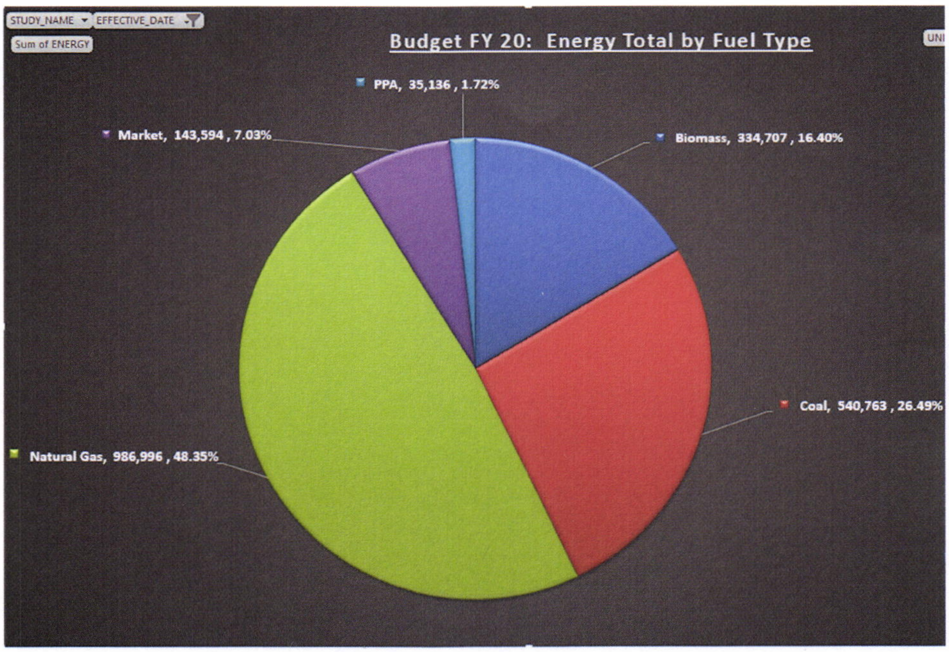
Some scenarios are for illustrative purposes only and should not be viewed as practical options to dispatch GRU's generating fleet. Due to NERC standards, GRU is required to have a plan in place to recover its Most Severe Single Contengency (MSSC) within 30 minutes. Since most of GRU's genration fleet takes longer than 30 minutes to start and serve load, relying on Market Power to serve load is not a viable option for the vast marjority of the year. Recoverability was not modeled in Scenarios 1, 2, or 3.

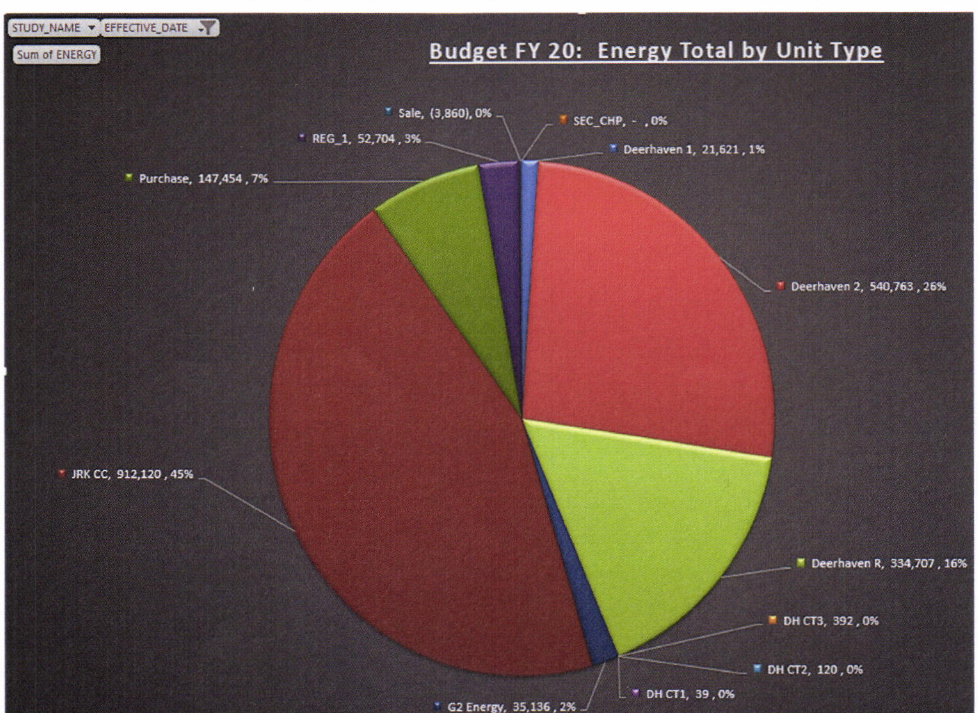
GRU also has a reserve obligation to the Florida Reserve Sharing Group of 42 MW which were not included in Scenarios 2 & 3. Typically GRU's operating plan to cover Reserves is to utilize a combination of spinning reserves (units already online with room to ramp up in MW) and quick-start generation.

GenTrader Output Summary

Base Case: FY20 Budget output

- 48% of the load was produced by Natural Gas Generation
  - JRK CC1 - 45% of the Total Generation
  - The SEC Units - ~3% of the Total Generation
  - Deerhaven Unit 1 - 1% of the Total Generation
- Market (Purchased Power) - 7% of the Total Generation
- DHR - 16% of the Total Generation
- Deerhaven Unit 2 - 27% of the Total Generation
- PPA (G2 Energy) - 2% of the Total Generation
- Study Cost - $ 77,317,410





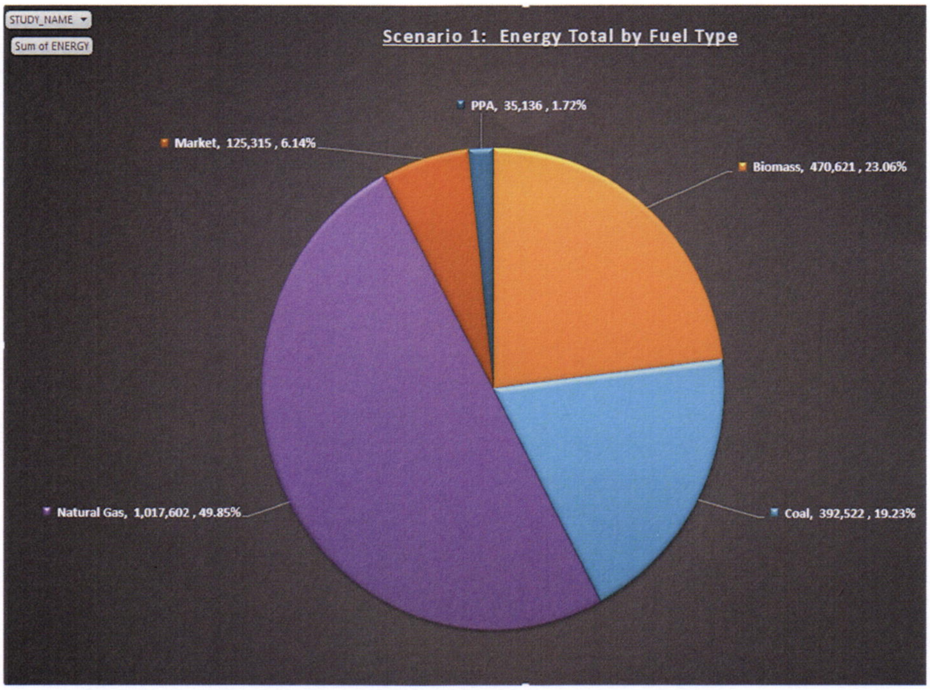
Scenario 1:

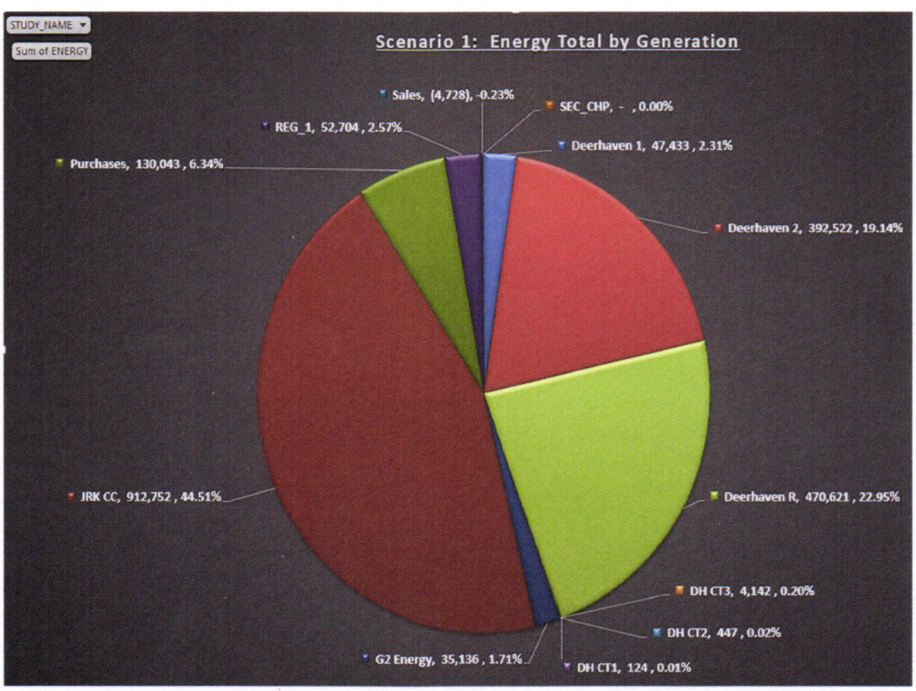
With all generation modeled as Economic Dispatch, DHR displaced Deerhaven Unit 2 by 7%.

- Deerhaven Unit 2 – Down to 19% of the Total Generation
- DHR – Up to 23% of the Total Generation
- Study Cost - $76,278,020 **($1,039,390 saved)**

There were no other major impacts to the generation output in this scenario.

Context: When dispatching the generation fleet, GRU plans for the contingency that its largest unit online could trip and that the system would need to recover within 30 minutes. As such, during the summer months and during periods of high load, GRU typically keeps DH2 online for reliability purposes.

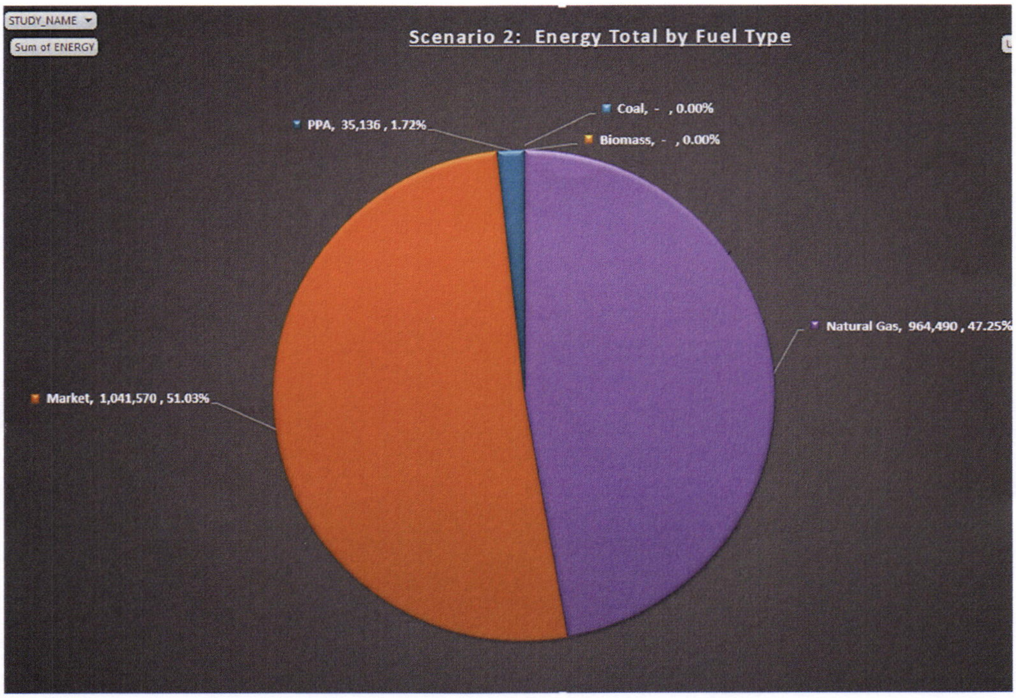


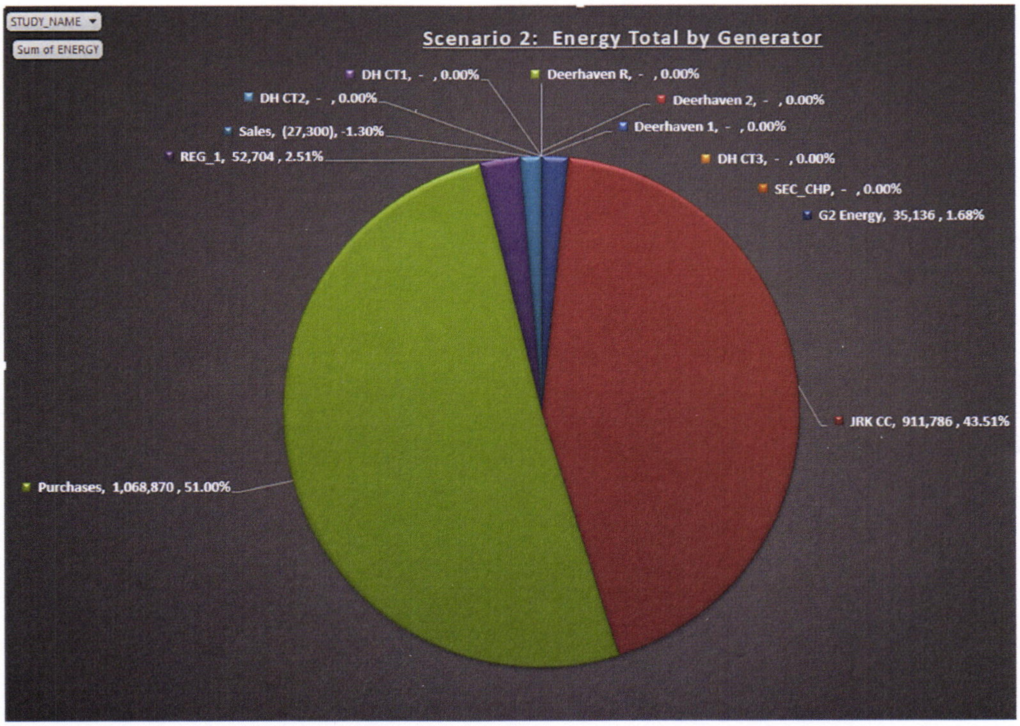


Scenario 2:

- With the Market Import Capability maximized (448 MW), the only generators that ran in this scenario were JRK CC1 and of course the SEC generators. No other generators ran due to the market being more economical.
- Study Cost - $62,978,110 **($14,339,300 saved)**

Context: In this scenario, the market imports are the hourly as-available prices for power and do not reflect day-ahead or preplanned purchases. Per NERC reliability standards, GRU is not able to run its system dependant upon hourly market purchases. GRU must be able to cover its load with either its own generation or planned (day/week/month-ahead) purchases. As such, this scenario is for illustrative purposes only and should not be viewed as a practical option to serve GRU native load.





Scenario 3:

In this scenario the Market Import Capability was maximized (448 MW). Also, JRK CC1 and DHR were both modeled as Must-run generators. The model did not run Deerhaven Units 1 & 2 at all in this scenario because the hourly market pricing was more economical.

- 47% of the load was produced by Natural Gas Generation
  - JRK CC1 - 44% of the Total Generation
  - The SEC units - ~3% of the Total Generation
- Market (Purchased Power) - 23% of the Total Generation
- DHR - 28% of the Total Generation
- PPA (G2 Energy) - 2% of the Total Generation
- Study Cost – $66,093,780 (**$11,223,630 saved**)

Context: As with Sceanario 2, GRU must be able to cover its load with either its own generation or planned (day/week/month-ahead) purchases. As such, this scenario is for illustrative purposes only and should not be viewed as a practical option to serve GRU native load.