GRU Electric Integrated Resource Plan (IRP) – Part 1 Executive Summary

IRP Process Overview

1. IRP Goals

-Set primary goals for IRP

-What do you want to accomplish?

-Develop an actionable, cost-effective plan to meet future electric needs

2. Inputs & Assumptions

-Build model to accurately reflect current GRU system:

- Plant capacities
- Unit Performance
- Costs (Fixed and Variable O&M)

-Input Forecasts:

- System Load
- Fuel Prices
- Financial (interest, inflation, etc.)

-Describe New Resource Options:

- Capital Costs
- Operating Costs
- Performance Details

3. Resource Needs

PLEXOS Model:

- Input allowances and constraints that account for real world
- Evaluates gaps in required generation capacity
- Fills gaps by providing resource portfolio with the lowest life-cycle costs
- Chronological listing of resource additions
- This resource mix becomes the baseline against which all others are compared

4. Evaluate Alternatives

-Multiple scenarios and sensitivities are run through the model

-Outputs are compared against the baseline for resource mix changes and cost changes

-Evaluation and comparison of differing outputs yields valuable insights

5. Develop Preferred Plan

After PLEXOS model is complete:

- GRU team weighs the performance of a given model output against a variety of futures
- Many factors are reviewed including:
  - Cost
  - Organization Financial Constraints
  - Reliability
  - Technology advantages
  - Timing
- GRU teams builds a preferred resource plan that is technically and economically feasible for the organization
- Preferred Plan is brought to board for input and approval

6. Implement Preferred Plan (Action Steps)

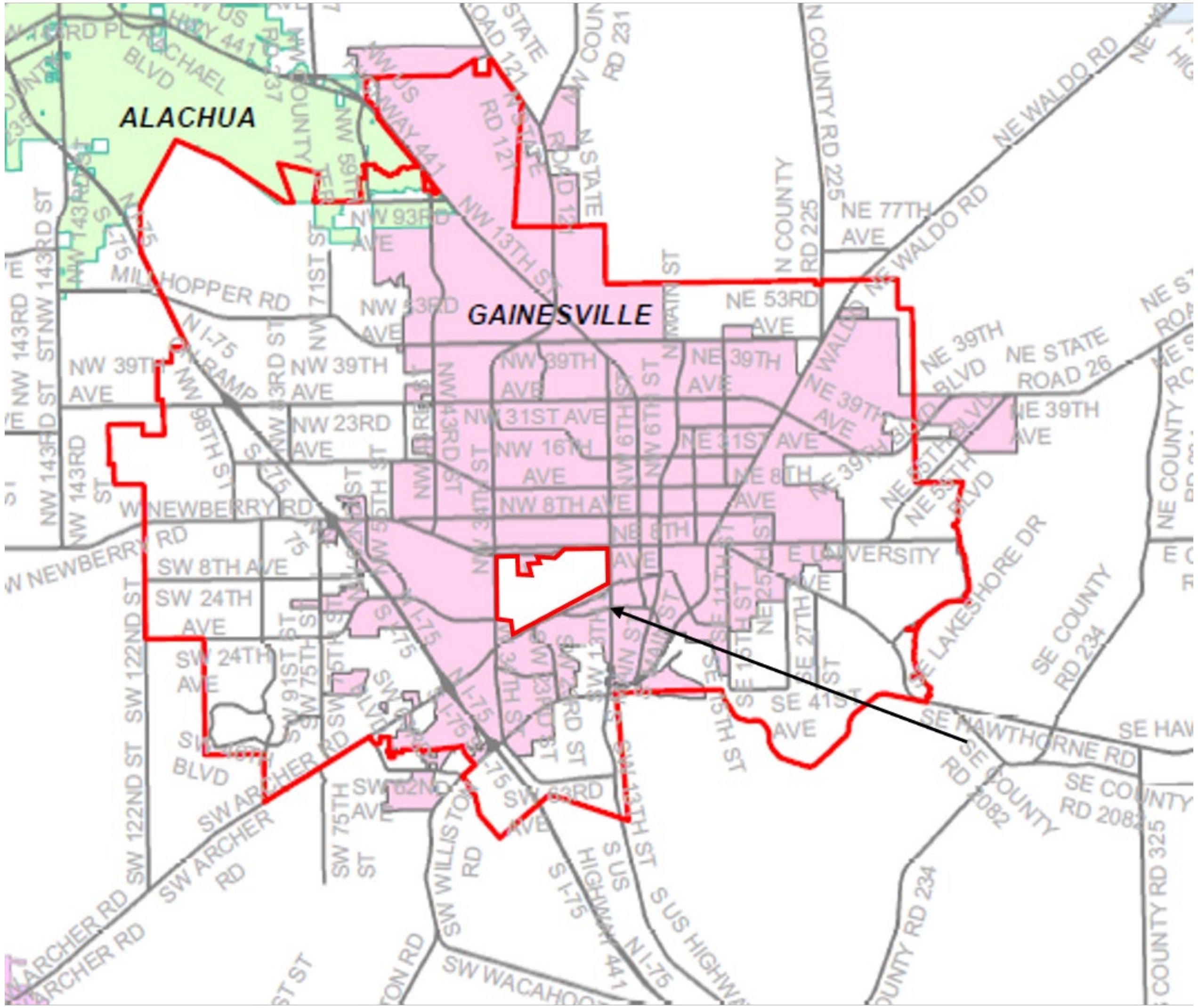
-Develop and execute steps to implement Preferred Plan

-Action Steps could include (among others):

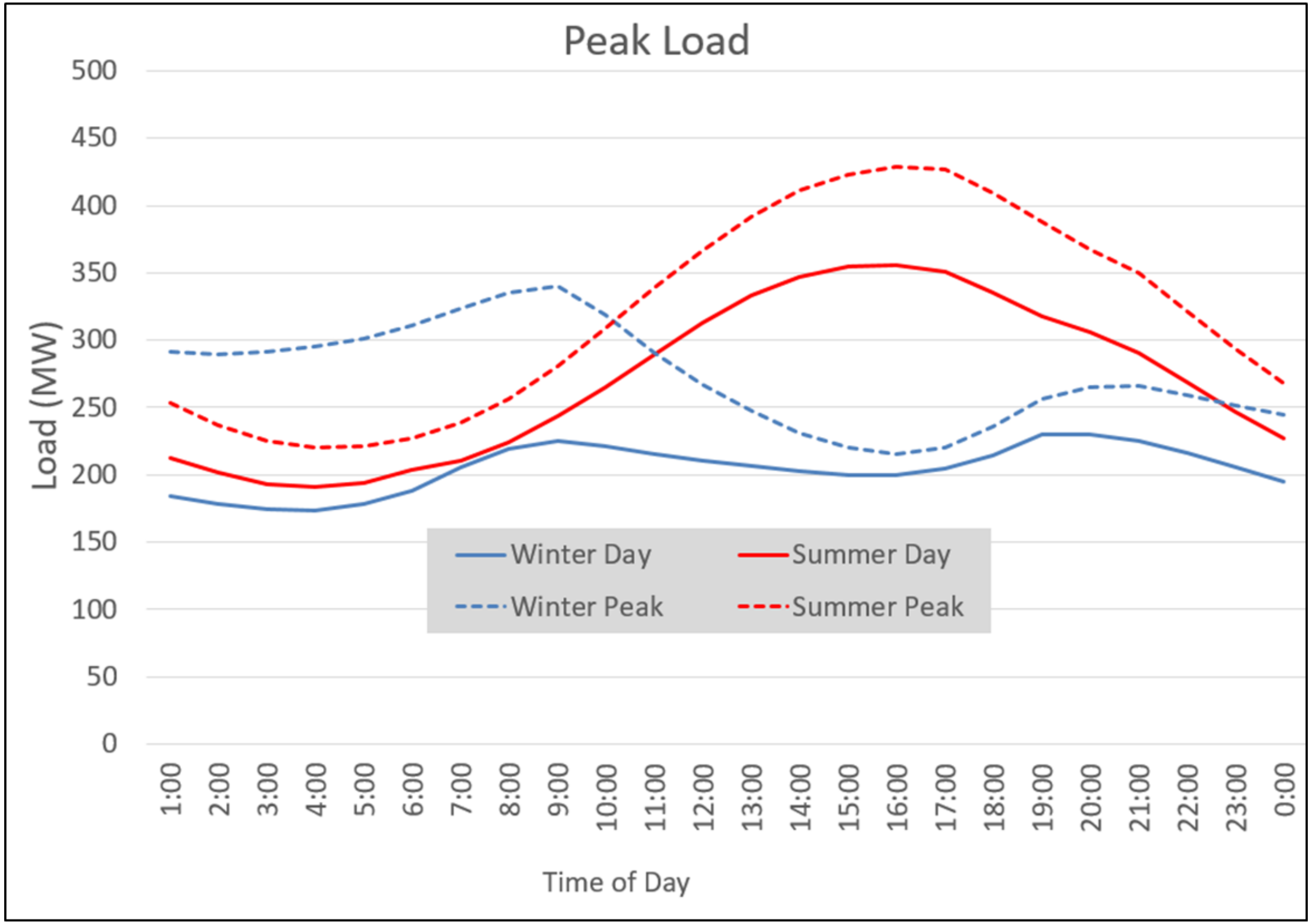
- Developing technical equipment specifications
- Engineering and Equipment Vendor RFPs
- Construction
- Executing Purchase Power Agreements

-Denotes most recent progress

GRU's Electric Service Territory



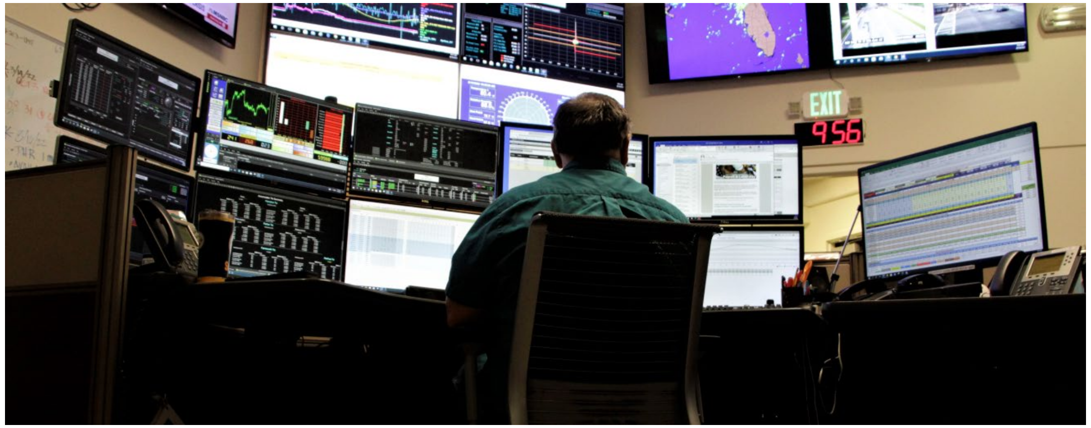
Peak Load Variation



How GRU Manages Its Energy Portfolio

Balanced, diverse, economic portfolio ensures power needs met reliably and cost effectively

- Baseload and Intermediate Units
  - Relatively higher efficiency
  - Slow start-up and shut-down times
- Firming (Peaking) Units
  - Lower efficiency
  - Fast start
- Intermittent (solar)
  - Take power when it is generated
- Power Trading



Overview of GRU Energy Supply

Plant	Unit Number	Fuel Types	Expected Retirement	Contribution to Summer Peak Demand (MW)
John R. Kelly	CC1	Natural Gas	12/2051	112
Deerhaven	DH1	Natural Gas / #6 oil	*12/2027	76
Deerhaven	DH2	Natural Gas / coal	12/2031	232
Deerhaven	CT1	Natural Gas / diesel	*12/2026	17.5
Deerhaven	CT2	Natural Gas / diesel	*12/2026	17.5
Deerhaven	CT3	Natural Gas	12/2046	71
South Energy Center	SEC1	Natural Gas	12/2039	3.8
South Energy Center	SEC2	Natural Gas	12/2047	7.4
Deerhaven Renewables	DHR	Biomass	12/2043	102.5
Sand Bluff Solar	-	-	12/2044	27

**Unit expected to retire in next 5 years*

Load Balancing

- GRU is a "Balancing Authority"
  - 60 balancing authorities in US
  - Monitor power load and supply to ensure continuous balance
  - Start, stop, "ramp up", or "ramp down" generating units
  - Import or export power from grid - Power Trading
- The owner of the load is responsible for balancing
  - Load = Customers
  - Load Balancing
    - Can be done by the owner
    - Can be outsourced to another vendor at the cost of the owner

Buying & Selling Power (continued)

Example: 50 MW (Peak) Dispatchable PPA in 2028

Size (MW)		50
Capacity Factor		50%
Annual Energy (MWh)		219,000
Capacity ($/kW-month)	$	7.28
Variable O&M ($/MWh)	$	1.68
Heat Rate (Btu/kWh)		7,000
Delivered Natural Gas Cost ($/MMBtu)	$	4.87
Gas Capacity Reservation Charge ($/MMBtu)	$	0.62
Total Natural Gas Cost ($/MMBtu)	$	5.49
Wheeling Cost ($/kW-month)*	$	2.99
Annual Capacity Cost ($)	$	4,369,611
Annual Variable O&M Cost ($)	$	368,056
Annual Fuel Cost ($)	$	8,416,170
Annual Wheeling Cost ($)	$	1,794,000
Total Cost	$	14,947,837
Total Cost per MWh	**$**	**68.25**

*Wheeling charges for the IRP were based upon FPL's tariffed transmission rate in 2023 of $2.67/kW-month. FPL increased this rate to $3.77/kW-month on 1/1/24. Escalated at 2.3% per year through 2028 for this example, this charge would be $4.13/kW-month, or an annual cost increase of $684,000.

IRP Process

- Assessment of future energy needs
- Evaluation of energy supply portfolios for meeting those needs
  - Reliable and compliant with all applicable regulations
  - Cost-Effective
  - Mitigate risks
- Plan satisfies energy needs over 25+ year horizon
- Road map for decision making
  - Drives actionable decisions over next ~5 years
- Industry Best Practice
  - Typically conducted every ~3-5 years
  - Reflect changes in technology, costs, industry trends, etc.

IRP Process

- Assumed GRU will be the power provider
  - Generated
  - Purchased
- Baseline is best estimate of future conditions
  - Minimal constraints
  - Not based on net-zero resolution
- Only 1 sensitivity has net-zero resolution
- All sensitivities and scenarios look at the lowest cost

IRP Considerations

- Several Deerhaven units nearing end-of-life
  - Additional resources needed to meet demands and comply with NERC standards
- Energy resource portfolio must be reliable, operable, and meet all regulatory standards
  - Meet peak demand with largest unit out of service "N-1" (NERC-TPL-001-4)
- Rate and debt concerns
- Lower fuel and O&M costs with newer units and technologies
- Evolving technologies
  - Plan must be based on commercially available technologies but allow flexibility for future technology shifts

PLEXOS Model

Energy Demand
- Peak demand
- Energy
- Hourly demand over year

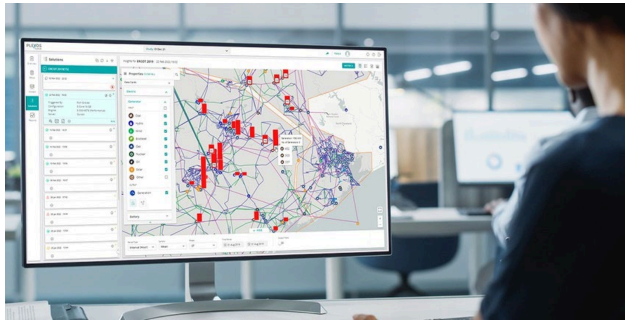
Resource Alternatives
- Capital costs
- Fixed & Variable O&M costs
- Heat rates
- Dispatchability

Energy Costs
- Fuel prices
- PPA costs
- Transmission costs

Financial
- Inflation rate
- Bond rate
- Discount rate

Constraints
- Reliability
- Plant retirements
- Transmission capacity
- Operability
- Other scenario/sensitivity-specific

PLEXOS



Outputs
- Lowest lifecycle cost portfolio
- Timeline for resource additions
- Emissions

Net Present Value (NPV)

- NPV used to compare lifecycle costs
- Industry standard metric evaluating cash flows over the lifetime of an investment
- Captures costs of serving energy requirements over the IRP study period (through 2050)
- Accounts for time value of money by applying a "discount rate" to future investments
- Allows comparison of alternatives with different cash flows

Thank you!

GRU[SM]
More than Energy

CONTACT US

https://www.gru.com

Appendix

Outline

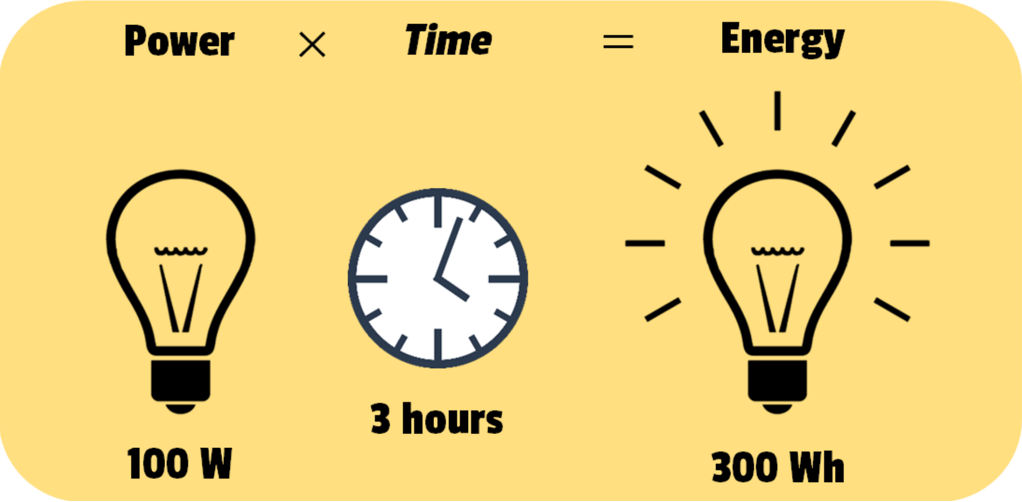
Part I: Background Information

- Electricity Basics
- Bulk Electric System (BES) Overview
- How Power is Produced
- Overview of GRU Energy Supply (Generating Units)
- Overview of GRU Energy Delivery (Transmission Assets)
- Load Balancing
- Buying and Selling Power
- IRP Process
- GRU Stakeholder and Community Engagement Approach

Part: II: Preliminary IRP Results

Demand (Power)

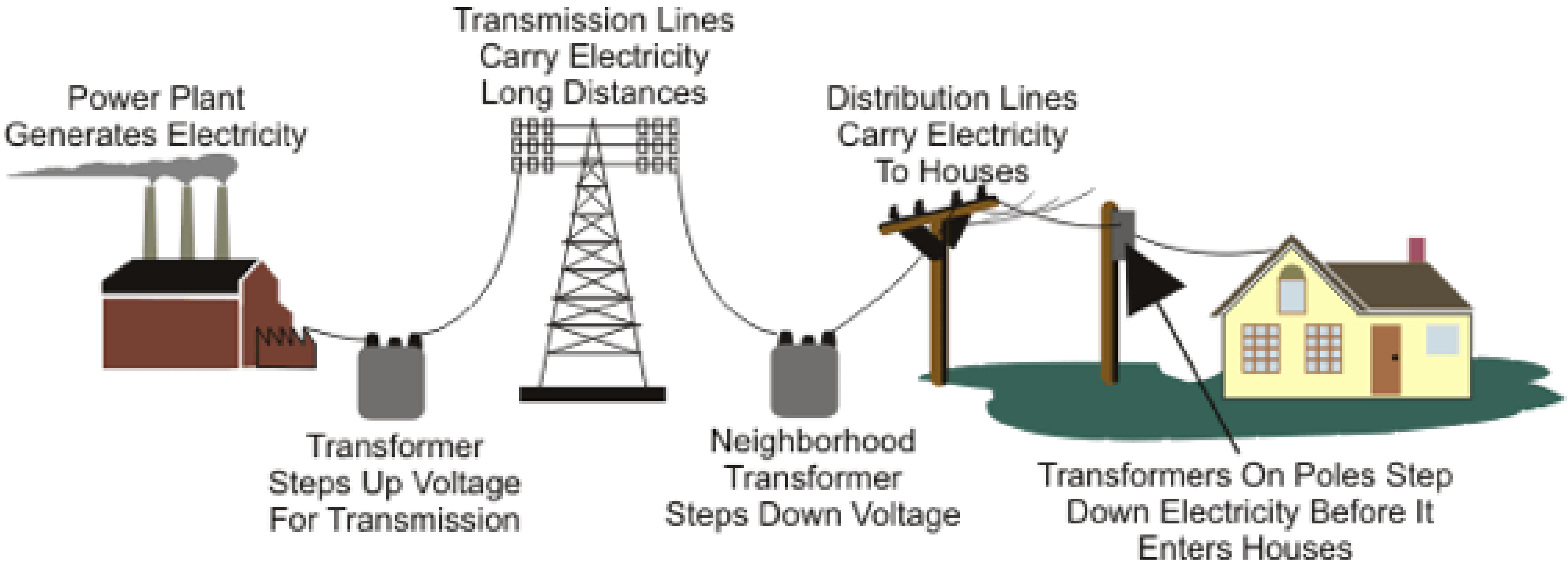
- Watt = unit of power
- 1 Kilowatt (kW) = 1,000 Watts
- 1 Megawatt (MW) = 1 Million Watts
- GRU peak demand (2023) = 409 MW



Energy (Power Consumed)

- Kilowatt hour (kWh) = kW x hours
- Average residential customer uses ~850 kWh/month
- GRU supplies total of 2 Million MWh of electricity/year

Bulk Electric System (BES) Overview



How Power is Produced

- Fuel Types
  - Natural Gas
  - Liquid Fuels (diesel, #6 fuel oil, etc.)
  - Coal
  - Biomass
  - Other (nuclear, hydrogen, etc.)
- Generation Types
  - Conventional steam turbine
  - Combustion turbine (CT)
  - Reciprocating Internal Combustion Engine (RICE)
  - Combined-Cycle (combustion turbine w/ steam turbine)
  - Utility-scale Solar
  - Other (wind, hydro, nuclear, geothermal)

Overview of GRU Energy Supply

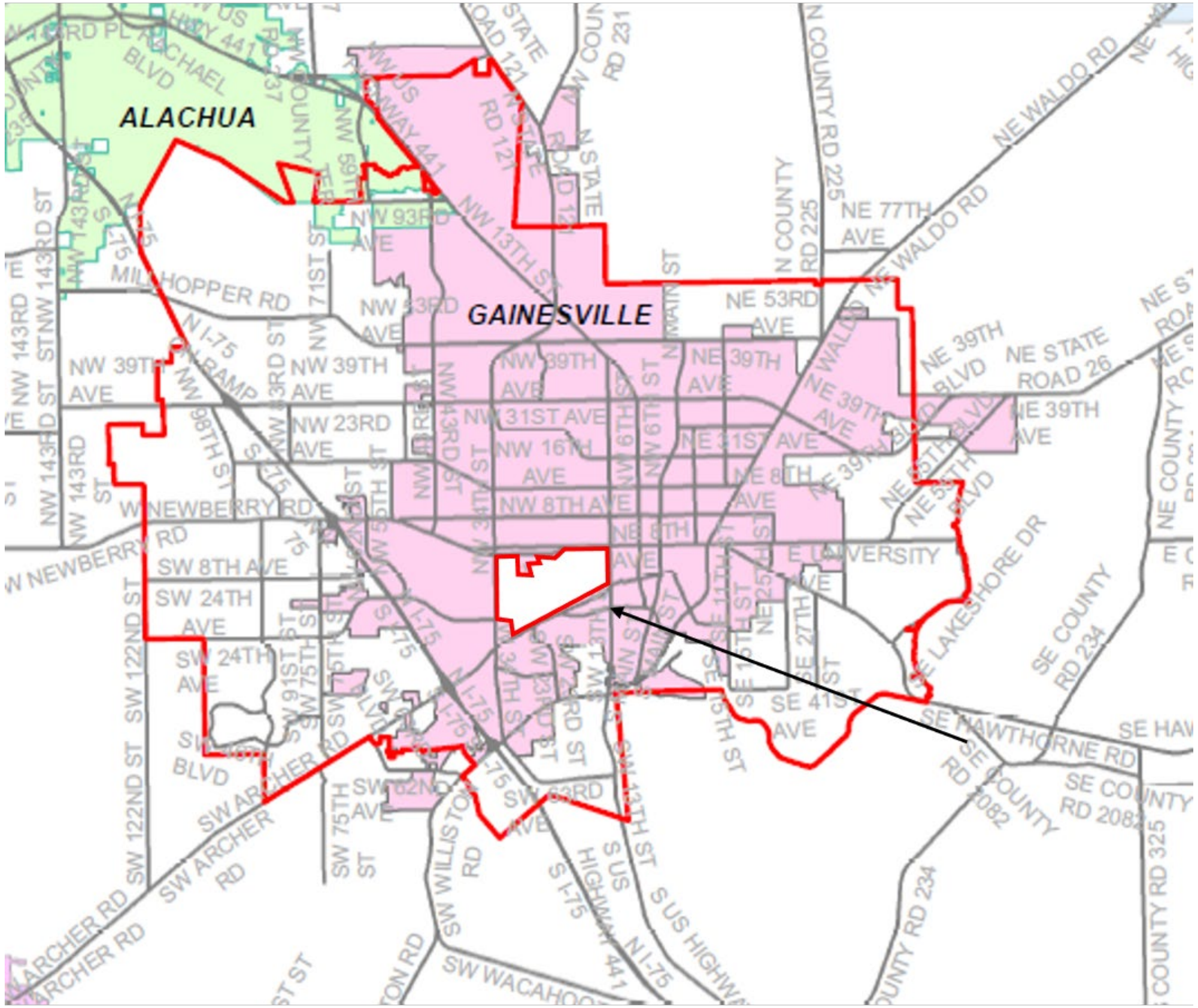
Plant	Unit Number	Fuel Types	Expected Retirement	Contribution to Summer Peak Demand (MW)
John R. Kelly	CC1	Natural Gas	12/2051	112
Deerhaven	DH1	Natural Gas / #6 oil	*12/2027*	76
Deerhaven	DH2	Natural Gas / coal	12/2031	232
Deerhaven	CT1	Natural Gas / diesel	*12/2026*	17.5
Deerhaven	CT2	Natural Gas / diesel	*12/2026*	17.5
Deerhaven	CT3	Natural Gas	12/2046	71
South Energy Center	SEC1	Natural Gas	12/2039	3.8
South Energy Center	SEC2	Natural Gas	12/2047	7.4
Deerhaven Renewables	DHR	Biomass	12/2043	102.5
Sand Bluff Solar	-	-	12/2044	27

*Unit expected to retire in next 5 years

Generation Types Modeled in IRP

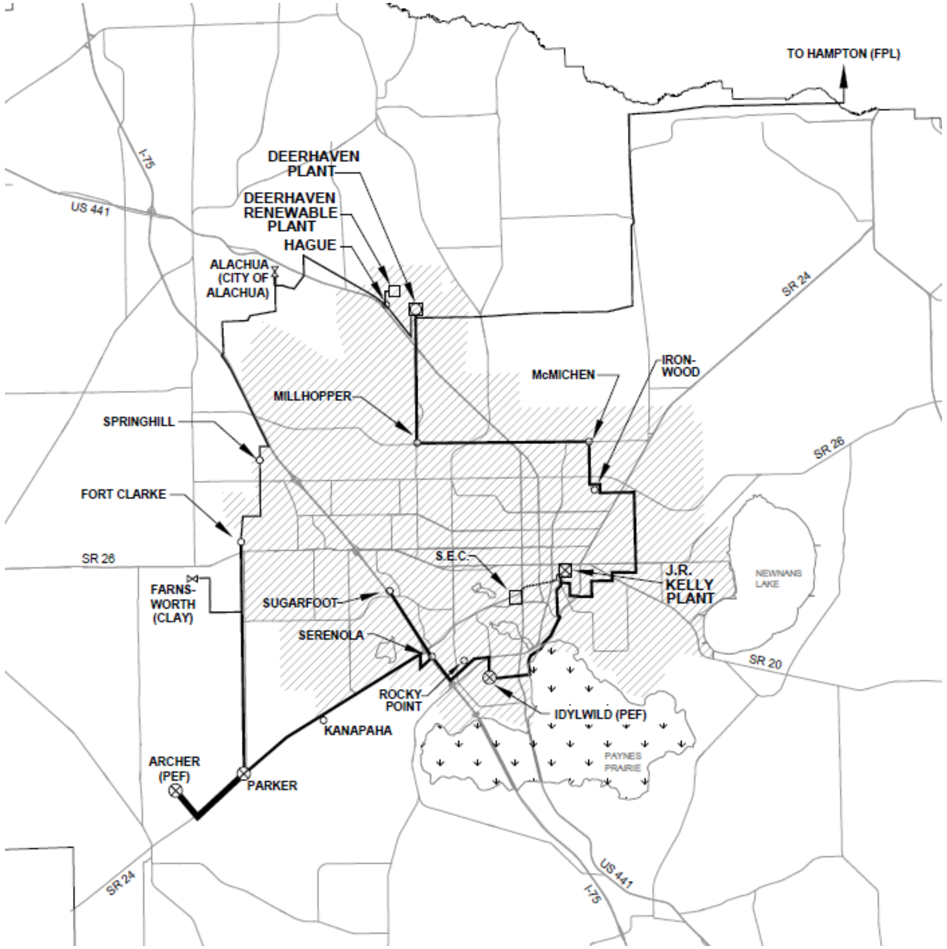
	Supply-Side Resource	Description	Finance Period Years	Max. Capacity Summer Net MW	Net Full Load Heat Rate Summer Btu/kWh	Capital Costs 2023 $, Millions	Capital Costs 2023 $ per kW, Summer
GRU Owned	Combined Cycle Combustion Turbine	NGCC - Siemens SGT-800 1x1	30	74.7	7,172	$162.3	$2,173
		NGCC - Siemens SGT-800 2x1	30	143.5	7,172	$320.9	$2,236
		NGCC - Siemens SGT-800 3x1	30	224.0	7,172	$471.7	$2,106
		Kelly Inlet Air Chilling	20	10.0	N/A	$10.5	$1,051
	Simple Cycle Combustion Turbine	Siemens SGT-800	30	52.4	9,818	$83.9	$1,601
		3 x Solar Titan 250	30	52.6	10,851	$97.2	$1,849
		1 x Solar Titan 250	30	17.5	10,851	$32.4	$1,849
		1 x Solar Titan 350	30	29.5	10,619	$41.3	$1,401
		2 x General Electric LM2500+G4	30	55.9	10,358	$123.7	$2,213
	Reciprocating Internal Combustion Engine	RICE - MAN 3x20 MW	30	59.0	8,680	$94.7	$1,605
		RICE - MAN 1x20 MW	30	19.7	8,680	$31.6	$1,605
	Nuclear[(Small Modular Reactors (SMR)]	Participant in 600 MW SMR project	40	100.0	10,447	$865.3	$8,653
	Biomass	Steam Turbine Fueled with Urban Waste Wood	30	30.0	13,500	$155.4	$5,180

GRU's Electric Service Territory



Overview of GRU Energy Delivery (Transmission Assets)

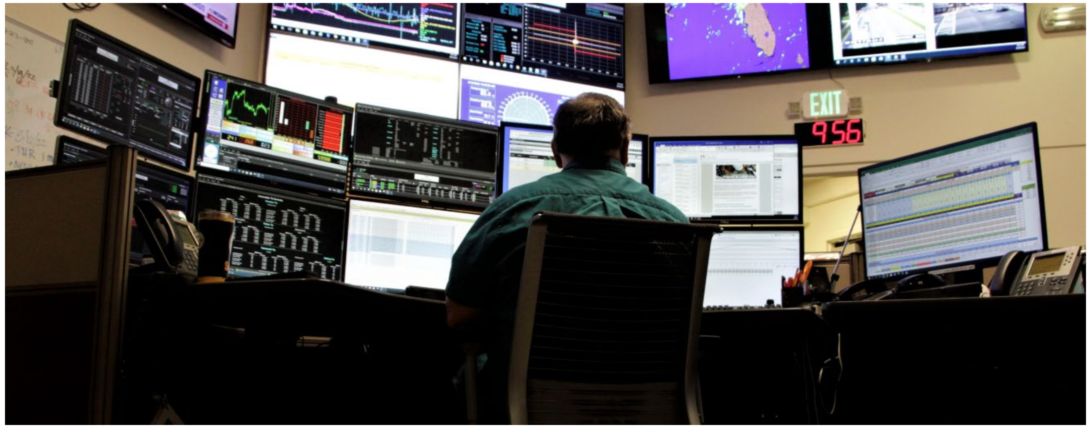
- 230 kV radial and a 138 kV loop connecting the following:
  - 3 primary generating stations
  - 11 distribution substations
  - 1x 230 kV and 1x 69 kV tie with Duke Energy Florida (DEF)
  - 138 kV intertie with Florida Power and Light Company (FPL)
  - Interconnection with Clay at Farnsworth Substation
  - Interconnection with the City of Alachua at Alachua No. 1 Substation



How GRU Manages Its Energy Portfolio

Balanced, diverse, economic portfolio ensures power needs met reliably and cost effectively

- Baseload and Intermediate Units
  - Relatively higher efficiency
  - Slow start-up and shut-down times
- Firming (Peaking) Units
  - Lower efficiency
  - Fast start
- Intermittent (solar)
  - Take power when it is generated
- Power Trading



Load Balancing

Utilities must meet electric load continuously under all conditions

- Natural gas curtailment periods
- Variable weather conditions
- Planned and unplanned outages

Regulatory Requirements

- North American Energy Reliability Corporation (NERC)
- Florida Energy Regulatory Commission (FERC)
- Florida Reliability Coordinating Council, Inc. (FRCC)

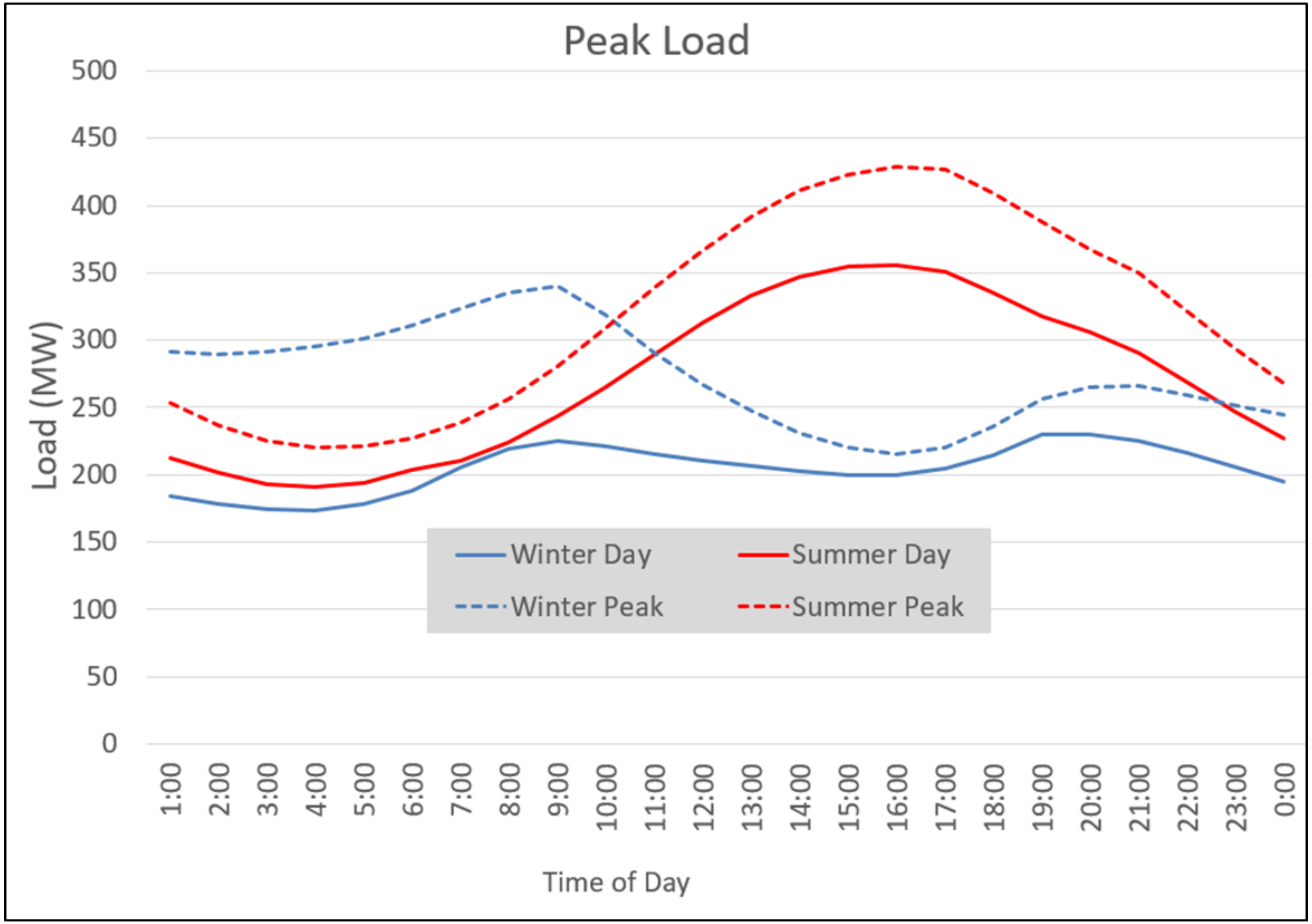
NERC

- Strict standards governing reliability & security (including cybersecurity)
- Reporting and audits to verify compliance

Load Balancing

- GRU is a “Balancing Authority”
  - 60 balancing authorities in US
  - Monitor power load and supply to ensure continuous balance
  - Start, stop, “ramp up”, or “ramp down” generating units
  - Import or export power from grid - Power Trading
- The owner of the load is responsible for balancing
  - Load = Customers
  - Load Balancing
    - Can be done by the owner
    - Can be outsourced to another vendor at the cost of the owner

Peak Load Variation



GRU More than Energy

Building Customer Trust
Infrastructure Reliability

Load Balancing (continued)

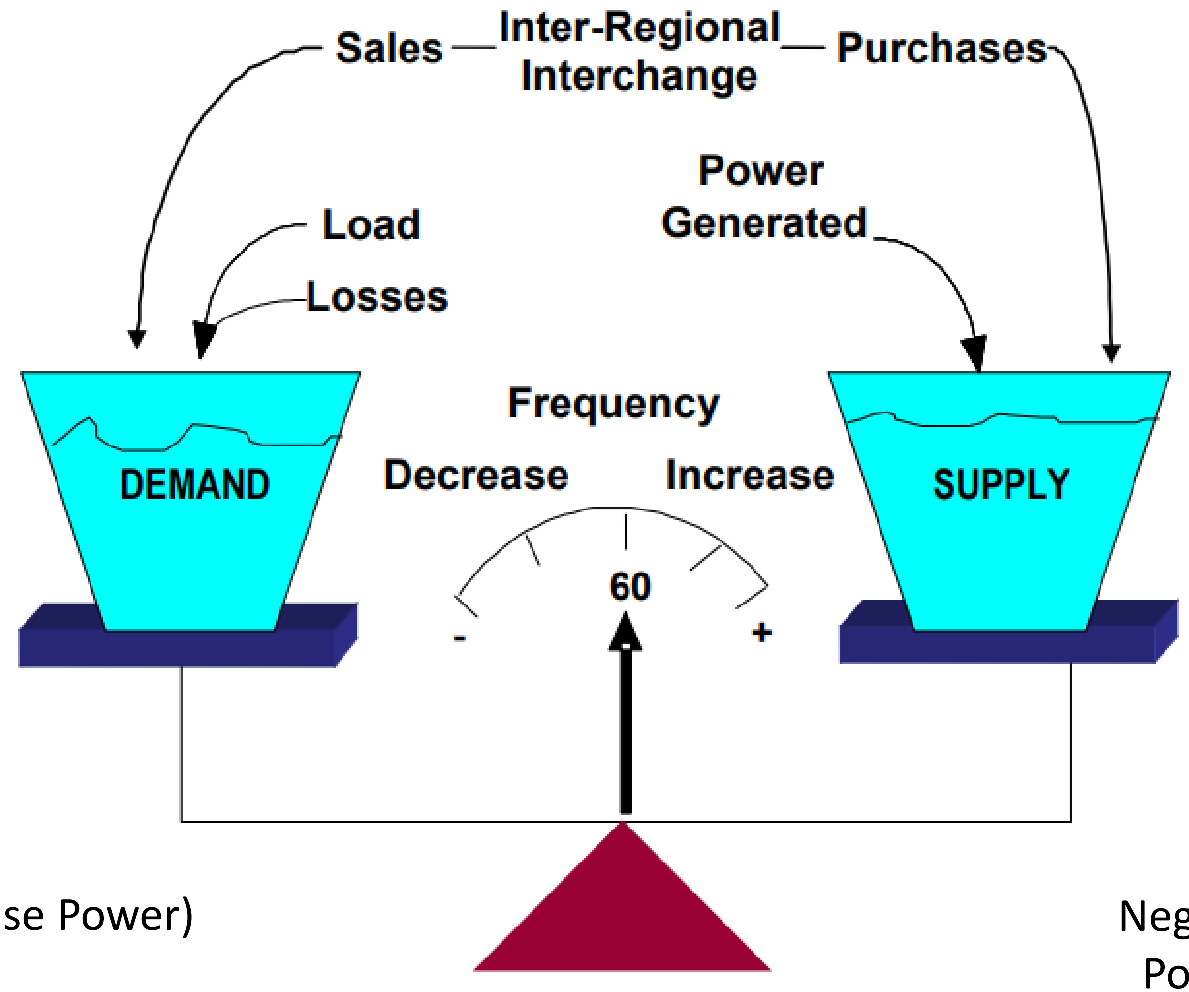


Figure 3a — Generation / Demand Balance

ACE = (Generation/Purchase Power) – (System Load)

Goal: ACE = 0

Negative ACE = Under-generating
Positive ACE = Over-generating

Buying & Selling Power

- GRU has transmission ties with FPL & Duke
- GRU purchases and sells power over these ties
  - GRU purchases and sells power from utilities across the southeast
- GRU participates in multiple power markets
  - Southeast Energy Exchange Market (SEEM): 15-minute intervals
  - Hourly market
  - Day-ahead market
  - Special short-term (a week or more) deals (outages, economic opportunities, etc.)
  - Long-term contracts (PPAs) (Winter Park, Alachua, Seminole, etc.)

Buying & Selling Power (continued)

- Transmission lines have limits over how much they can move
  - Transmission availability can vary hour-to-hour
  - Transmission can be reserved for long-term deals (if available)
- Transmission rates or "wheeling charges"
  - Charges associated with transferring purchased power over someone else's transmission lines
  - Rates are governed by the PSC and are non-negotiable

Long-term Power Purchases (PPAs)

- Typically consist of capacity, non-fuel variable O&M, and fuel charges
  - Capacity and O&M charges can be fixed or escalating
  - Fuel charges are pegged to a heat rate (generating unit efficiency) and the delivered cost of natural gas each month
- Wheeling costs are additional and cumulative for the transmission systems the power flows across

Buying & Selling Power (continued)

Example: 50 MW (Peak) Dispatchable PPA in 2028

Size (MW)		50
Capacity Factor		50%
Annual Energy (MWh)		219,000
Capacity ($/kW-month)	$	7.28
Variable O&M ($/MWh)	$	1.68
Heat Rate (Btu/kWh)		7,000
Delivered Natural Gas Cost ($/MMBtu)	$	4.87
Gas Capacity Reservation Charge ($/MMBtu)	$	0.62
Total Natural Gas Cost ($/MMBtu)	$	5.49
Wheeling Cost ($/kW-month)*	$	2.99
Annual Capacity Cost ($)	$	4,369,611
Annual Variable O&M Cost ($)	$	368,056
Annual Fuel Cost ($)	$	8,416,170
Annual Wheeling Cost ($)	$	1,794,000
Total Cost	$	14,947,837
Total Cost per MWh	**$**	**68.25**

*Wheeling charges for the IRP were based upon FPL's tariffed transmission rate in 2023 of $2.67/kW-month. FPL increased this rate to $3.77/kW-month on 1/1/24. Escalated at 2.3% per year through 2028 for this example, this charge would be $4.13/kW-month, or an annual cost increase of $684,000.

IRP Process

- Assessment of future energy needs
- Evaluation of energy supply portfolios for meeting those needs
  - Reliable and compliant with all applicable regulations
  - Cost-Effective
  - Mitigate risks
- Plan satisfies energy needs over 25+ year horizon
- Road map for decision making
  - Drives actionable decisions over next ~5 years
- Industry Best Practice
  - Typically conducted every ~3-5 years
  - Reflect changes in technology, costs, industry trends, etc.

IRP Process

- Assumed GRU will be the power provider
  - Generated
  - Purchased
- Baseline is best estimate of future conditions
  - Minimal constraints
  - Not based on net-zero resolution
- Only 1 sensitivity has net-zero resolution
- All sensitivities and scenarios look at the lowest cost

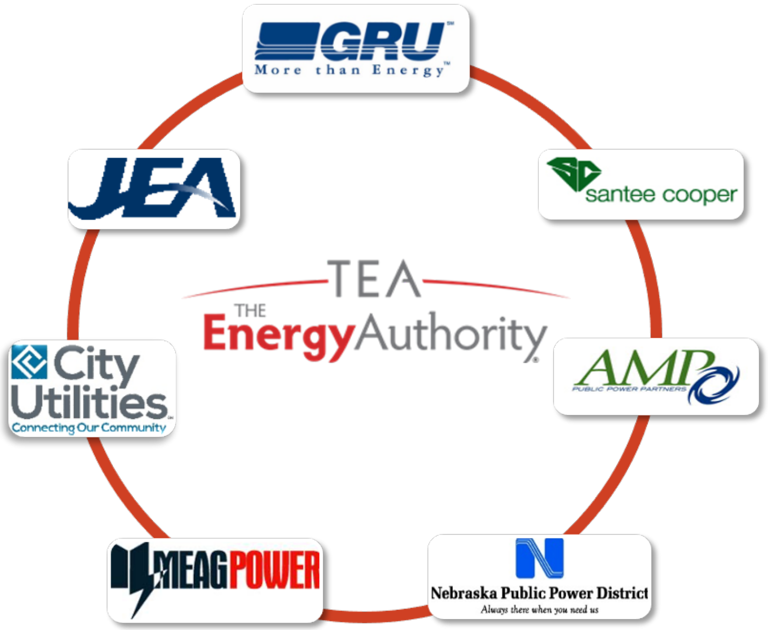
IRP Considerations

- Several Deerhaven units nearing end-of-life
  - Additional resources needed to meet demands and comply with NERC standards
- Energy resource portfolio must be reliable, operable, and meet all regulatory standards
  - Meet peak demand with largest unit out of service "N-1" (NERC-TPL-001-4)
- Rate and debt concerns
- Lower fuel and O&M costs with newer units and technologies
- Evolving technologies
  - Plan must be based on commercially available technologies but allow flexibility for future technology shifts

IRP Technical Team

- The Energy Authority (TEA) performing technical analysis
  - Input from GRU technical staff and 3rd party consultant, nFront Consulting

- TEA is a non-profit corporation that works on behalf of public power and other community owned organizations in the power and natural gas markets
  - Over 50 public power clients
  - GRU is 1 of 7 TEA owners, joining in 1999
  - GRU's CEO/GM is a Board member of TEA



IRP Technical Team (continued)

- GRU utilizes many of TEA's services, including:
  - Bilateral energy trading
  - Natural gas trading
  - Portfolio management
  - Risk management
  - Advisory services
- TEA has completed over 20 IRPs for other municipal utilities
  - TEA worked with GRU to complete its 2016 and 2019 IRPs
- NFront Consulting
  - Electric Power industry planning services
  - Numerous IRPs for various sized municipal electric utilities
  - Assisting in stakeholder engagement

PLEXOS Model

Energy Demand
- Peak demand
- Energy
- Hourly demand over year

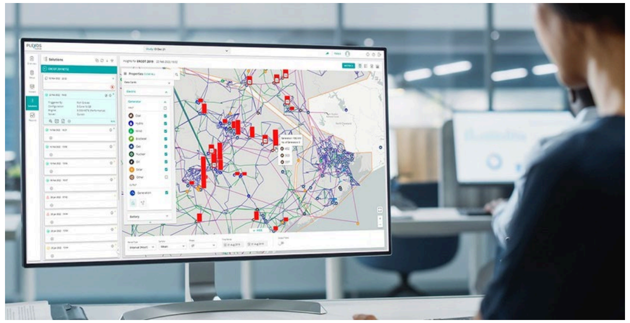
Resource Alternatives
- Capital costs
- Fixed & Variable O&M costs
- Heat rates
- Dispatchability

Energy Costs
- Fuel prices
- PPA costs
- Transmission costs

Financial
- Inflation rate
- Bond rate
- Discount rate

Constraints
- Reliability
- Plant retirements
- Transmission capacity
- Operability
- Other scenario/sensitivity-specific

PLEXOS



Outputs
- Lowest lifecycle cost portfolio
- Timeline for resource additions
- Emissions

Information Sources for Inputs to IRP

Energy Demand	Resource Alternatives	Energy Costs	Financial
• Peak demand • Energy • Hourly demand over year	• Capital costs • Fixed & Variable O&M costs • Heat rates • Dispatchability	• Fuel prices • PPA costs • Transmission costs	• Inflation rate • Bond rate • Discount rate

UF Bureau of Economic and Business Research
UNIVERSITY of FLORIDA

eia Independent Statistics and Analysis
U.S. Energy Information Administration

Sargent & Lundy

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

NREL Transforming ENERGY

S&P Global Commodity Insights

IRP Process (continued)

- PLEXOS
  - Specialized software used for IRP analysis
  - Applies mixed integer programming to perform multi-operational decision optimization
  - Replicates actual electric system operation with all technical constraints modeled and obeyed
  - Solves for the lowest life-cycle cost resource portfolio that meets demand and energy needs on an hourly basis
  - NERC regulations for reliability and reserve margin must be met
- Considers all costs for each resource portfolio option
  - Capital Outlays
  - Fixed and variable O&M
  - Fuel costs
  - PPA costs
  - Firming power required for utility scale solar

IRP Process (continued)

- "Baseline"
  - Model inputs based on most likely anticipated future based on industry forecasts
  - PLEXOS solves for lowest lifecycle cost portfolio that meets energy needs
- Multiple "Scenarios" and "Sensitivities" also evaluated to account for other possible futures
  - 19 scenarios and sensitivities modeled
  - Achieving 2045 net-zero carbon emission per 2018 City Commission Resolution was only one of 15 sensitivities modeled (not part of the baseline)
- IRP provides a robust preferred resource plan that will mitigate risks across multiple futures and fit within debt defeasance plan

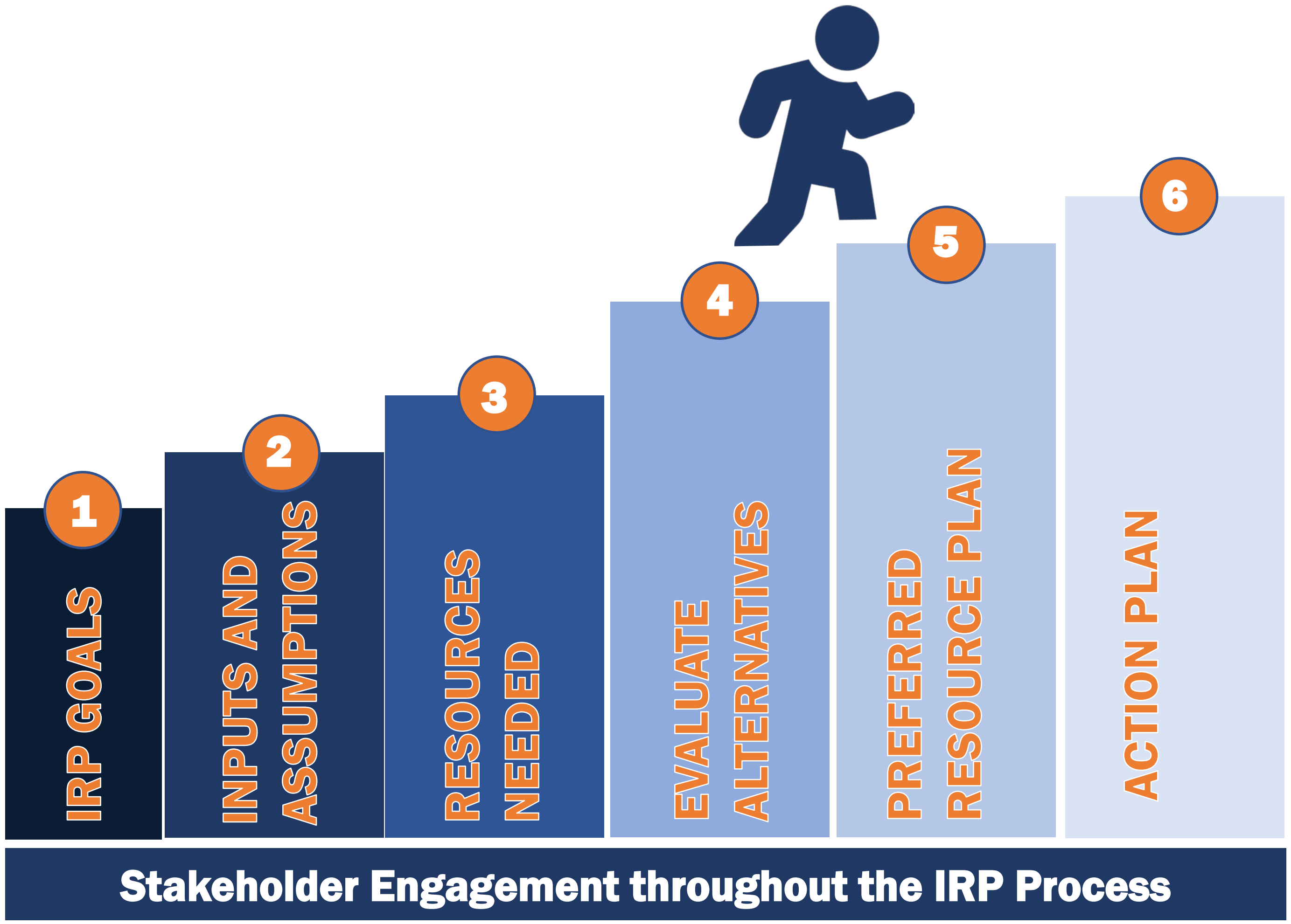
Net Present Value (NPV)

- NPV used to compare lifecycle costs
- Industry standard metric evaluating cash flows over the lifetime of an investment
- Captures costs of serving energy requirements over the IRP study period (through 2050)
- Accounts for time value of money by applying a "discount rate" to future investments
- Allows comparison of alternatives with different cash flows

GRU Stakeholder and Community Engagement Approach

- Purpose
  - Educate and get input from broad cross-section of stakeholders with various interests
    - Business
    - Low Income customers
    - Environmental & civic
- Industry Best Practice
  - Facilitate buy-in of final plan
- Stakeholder Engagement/Public Outreach Team
  - Acuity Design Group (ADG)
  - nFront Consulting
  - TEA
  - GRU Staff
- Stakeholder Advisory Group
  - Initiated March 2023
  - Diverse group representing cross-section of interests and perspectives
  - 6 stakeholder technical meetings
- Community Engagement Meetings
  - 6 Meetings

GRU Stakeholder and Community Engagement Approach



Next Steps

- Preliminary IRP Results - February 7
- Development of Preferred Resource Plan
  - Develop Internally
  - January - March
- Proposed Preferred Resource Plan to GRUA - April 17
- Final Stakeholder Advisory Group and Community Meetings – May