Community-Based Transactive Coordination Mechanism for Enabling Grid-Edge Systems

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Overview

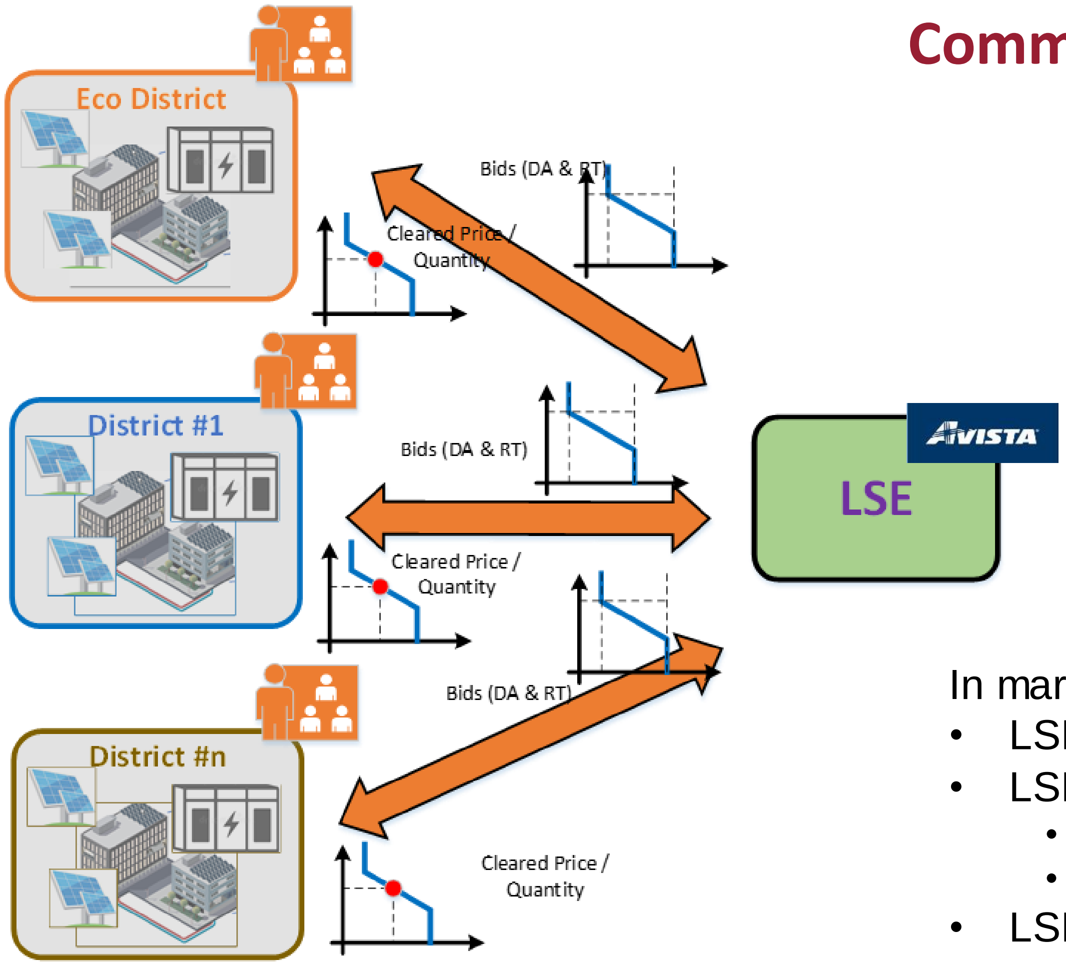
- Motivation
- How are communities defined
- What is the mechanism
- How is this simulated
- Results/Interpretation

How can we leverage DERs to lower prices for consumers and provide grid services?

Washington State University

Avista

Community Architecture



In market cycle (~5/15 minutes)

- LSE collects bids from all communities
- LSE runs a retail market operation
  - Optimal allocation
  - Maximize Social Welfare
- LSE send dispatch to all communities
  - Cleared price and quantities.

Community District Optimization

$$\text{Min.}\sum_{t=1}^{24}\left[P^{forecast}(t) * \underbrace{Q^{Load forecast}(t)}_{\text{Building Load - inflexible}} - P^{forecast}(t) * \underbrace{Q_i^{PV\ forecast}(t)}_{\text{PVs - estimate}} \pm P^{forecast}(t) * \underbrace{Q_i^{BESS}(t)}_{\text{BESS - flexible}}\right]$$

Constraints:

- BESS SOC dynamics
- PV Forecast – Data-driven
- Plug Forecast – Data-driven

Outputs:

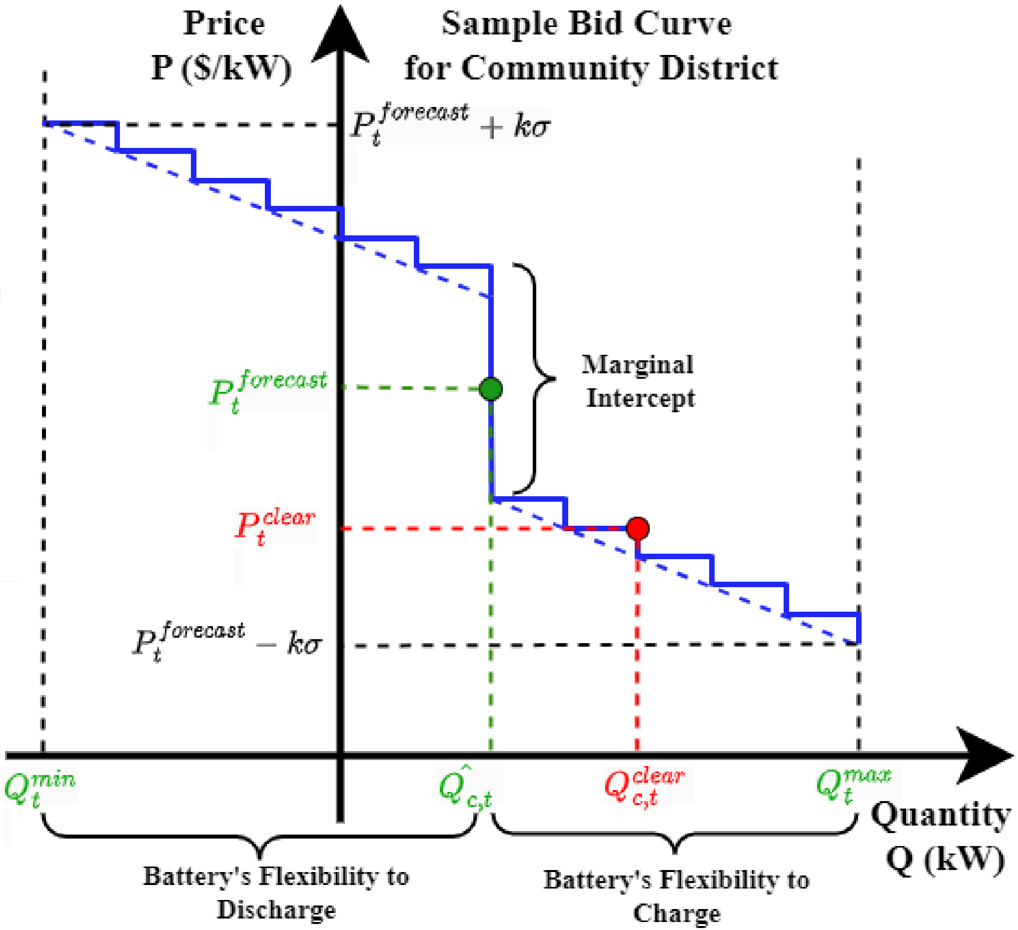
- BESS DA schedules
    - Active Power (Q_{DA}^{BESS})
    - SOC (SOC_{DA}^{BESS})

LSE Market Optimization

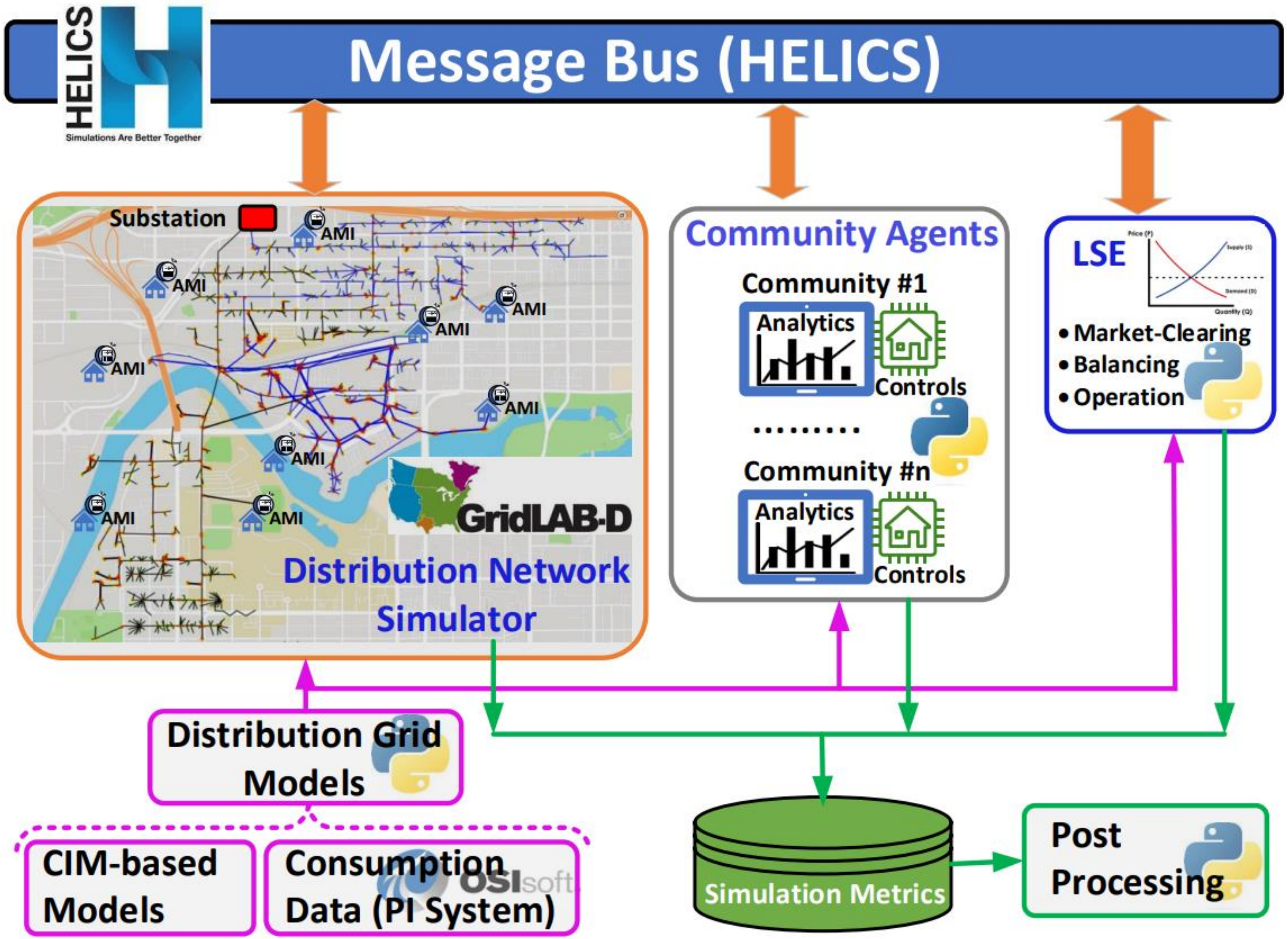
$$\underset{Q_{LSE},Q_c^j}{\text{minimize}} \quad (P_t^{actual} * Q_{LSE,t}) - \sum_{j=1} Cost^j(Q_{c,t}^j)$$

$$\text{Subject To:} \quad Q_{LSE,t} + \sum_{j=1}^{N} Q_{c,t}^j = 0;$$

$$Q_{LSE,t} \geq 0; \quad Q_{c,t}^{j,min} \leq Q_{c,t}^j \leq Q_{c,t}^{j,max}$$



An Example Real-Time Bid Curve for a Singular Community District



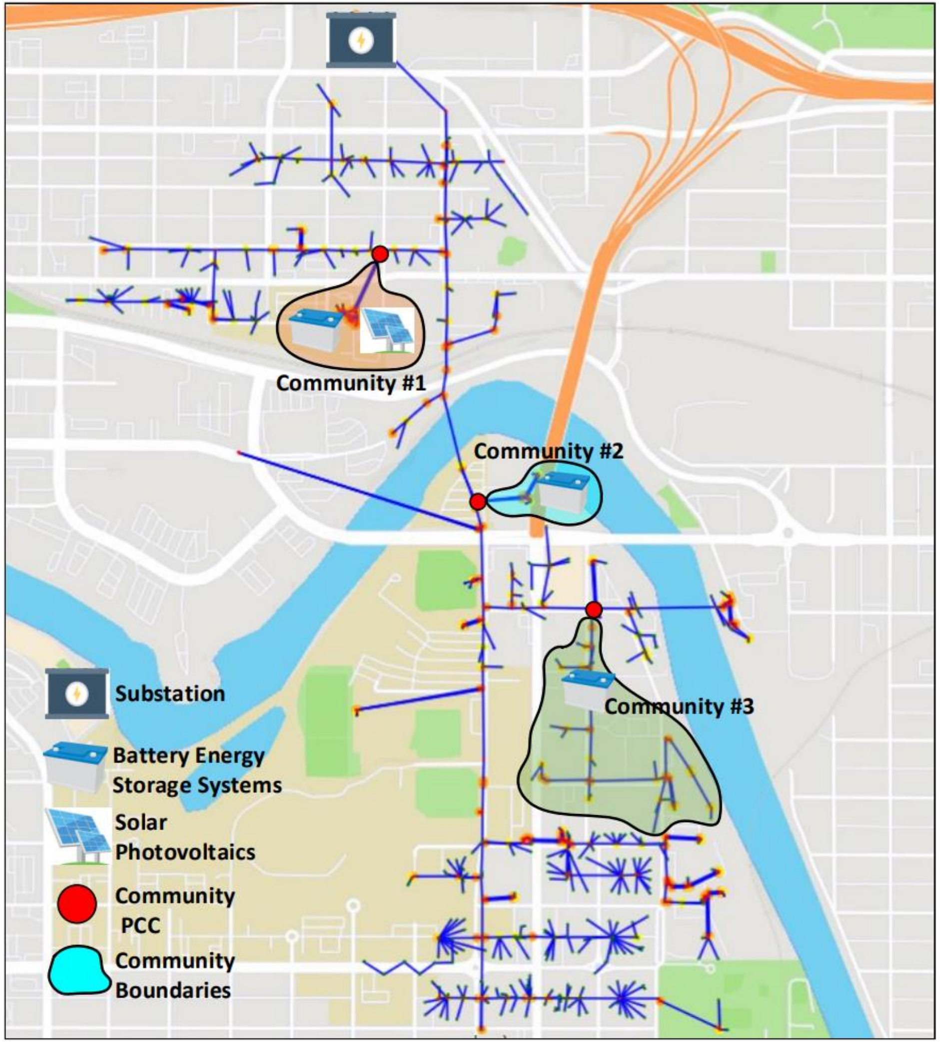
Co-Simulation Platform

Test System and Community Boundaries

- Communities will leverage wholesale energy market forecasts, building forecasts, and weather forecasts

- Communities will lower prices for eachother by communicating these flexibilities

District Area	Asset Type	Asset Capacity	Inverter Efficiency	Inverter rating
District 1	PV	254.35 kW	0.98	254.35 kW
District 1	Battery	1320 kWHr	0.95	660.00 kW
District 2	Battery	334.8 kWHr	0.95	168.15 kW
District 3	Battery	334.8 kWHr	0.95	168.15 kW

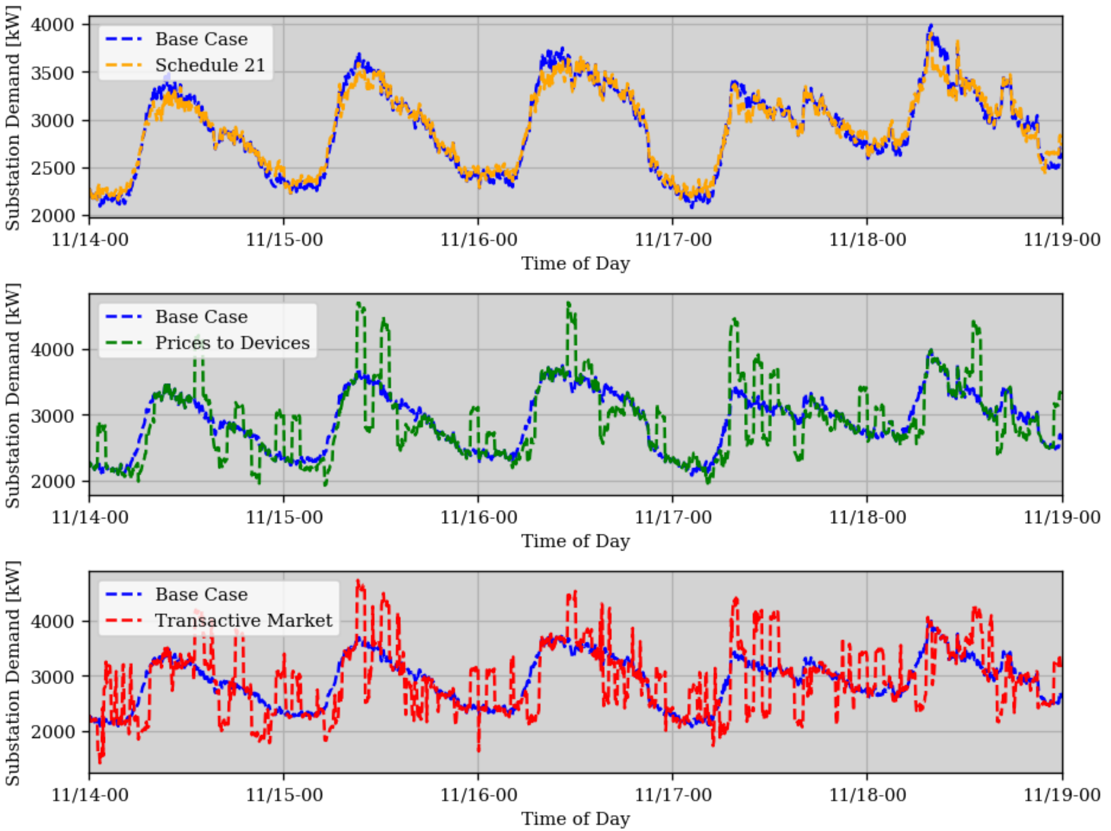


Use-Case Description

1) **Schedule 21**
   - ➢ **Normal customer flat-rate electricity charge with demand charge**

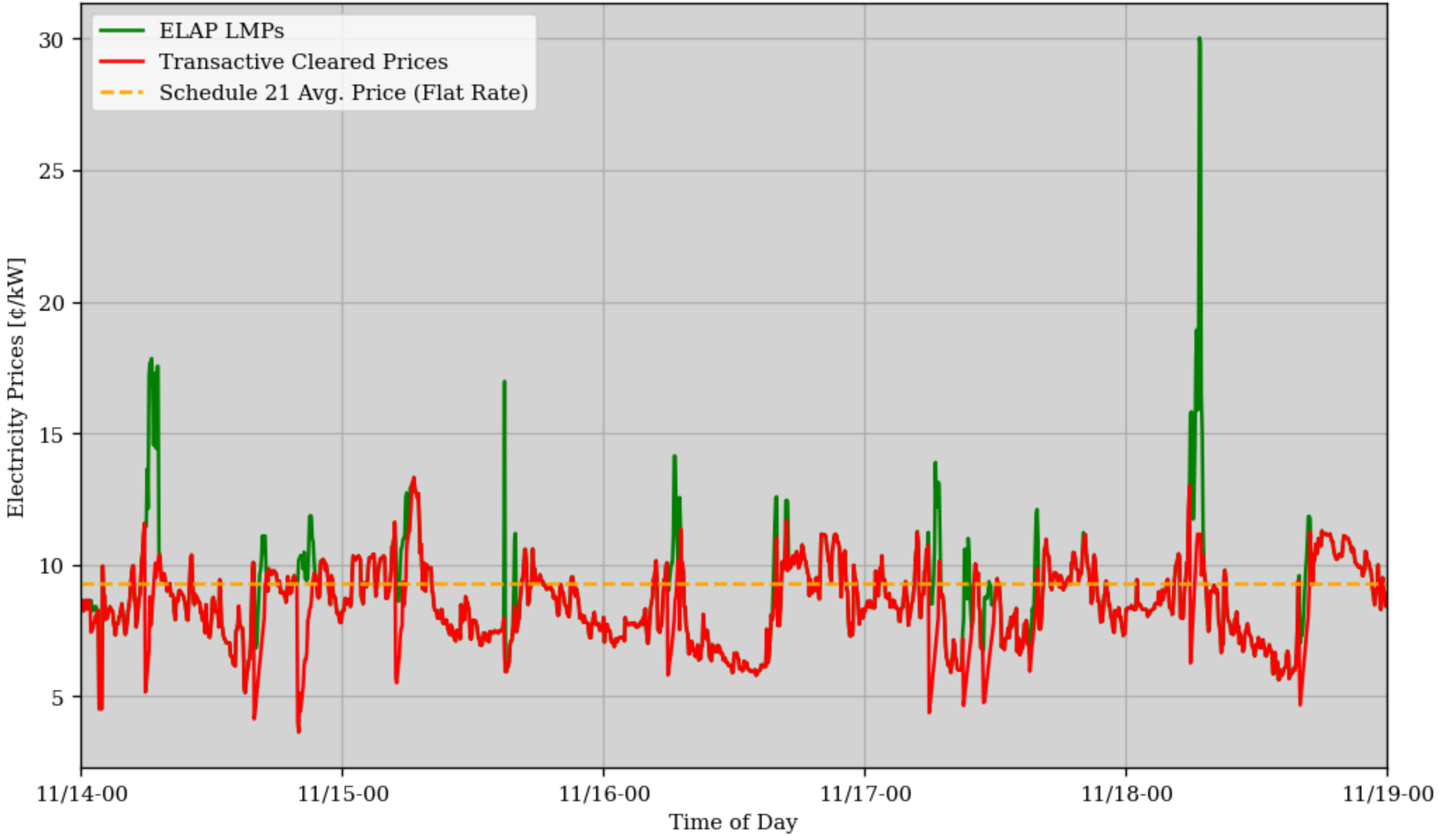
2) **Prices to Devices**
   - ➢ **Wholesale Prices with no demand charge**

3) **Transactive Market**
   - ➢ **Wholesale Prices and no demand charge with Market Coordination**



Substation Demand over 5-day interval

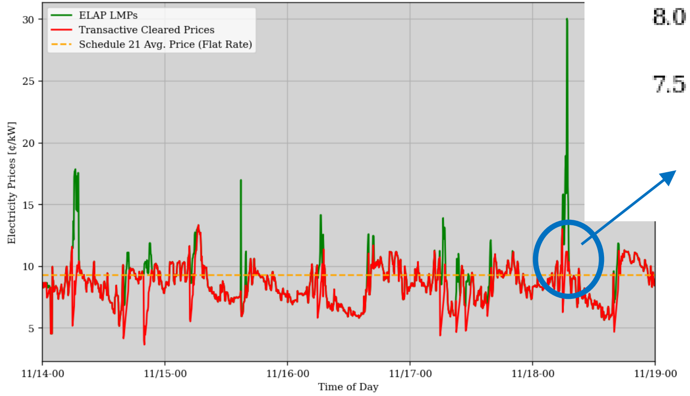
Transactive Market Cleared Prices

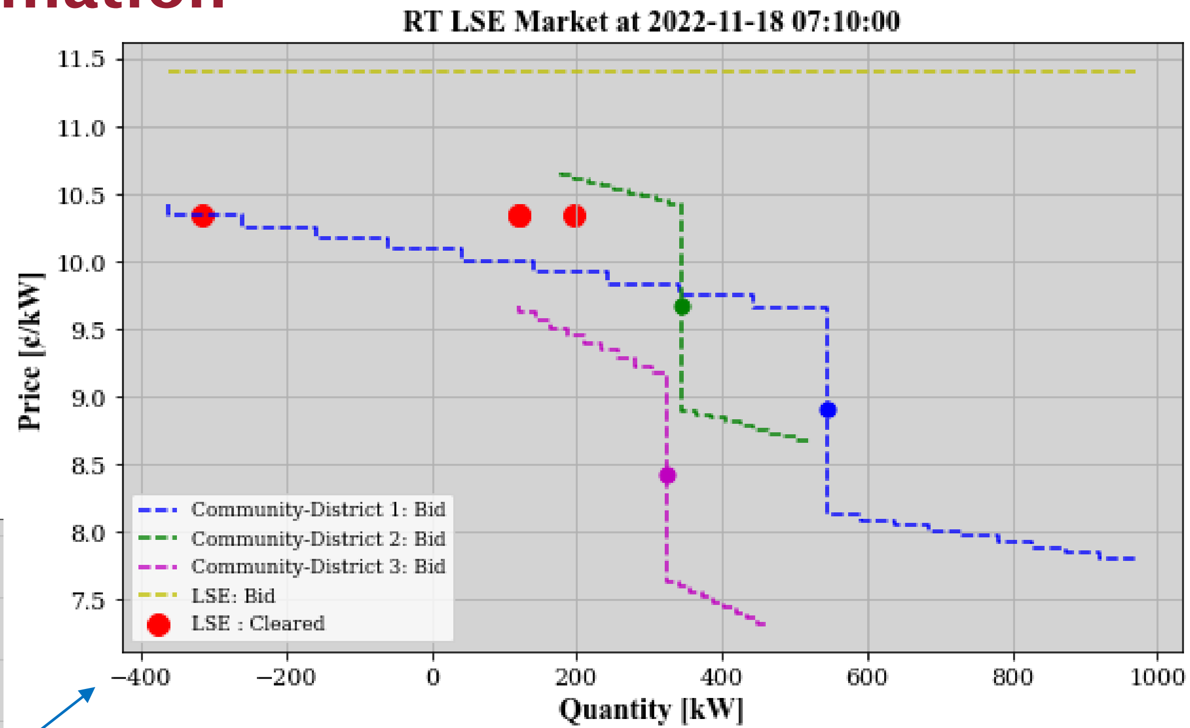


Cleared Prices over 5-day interval

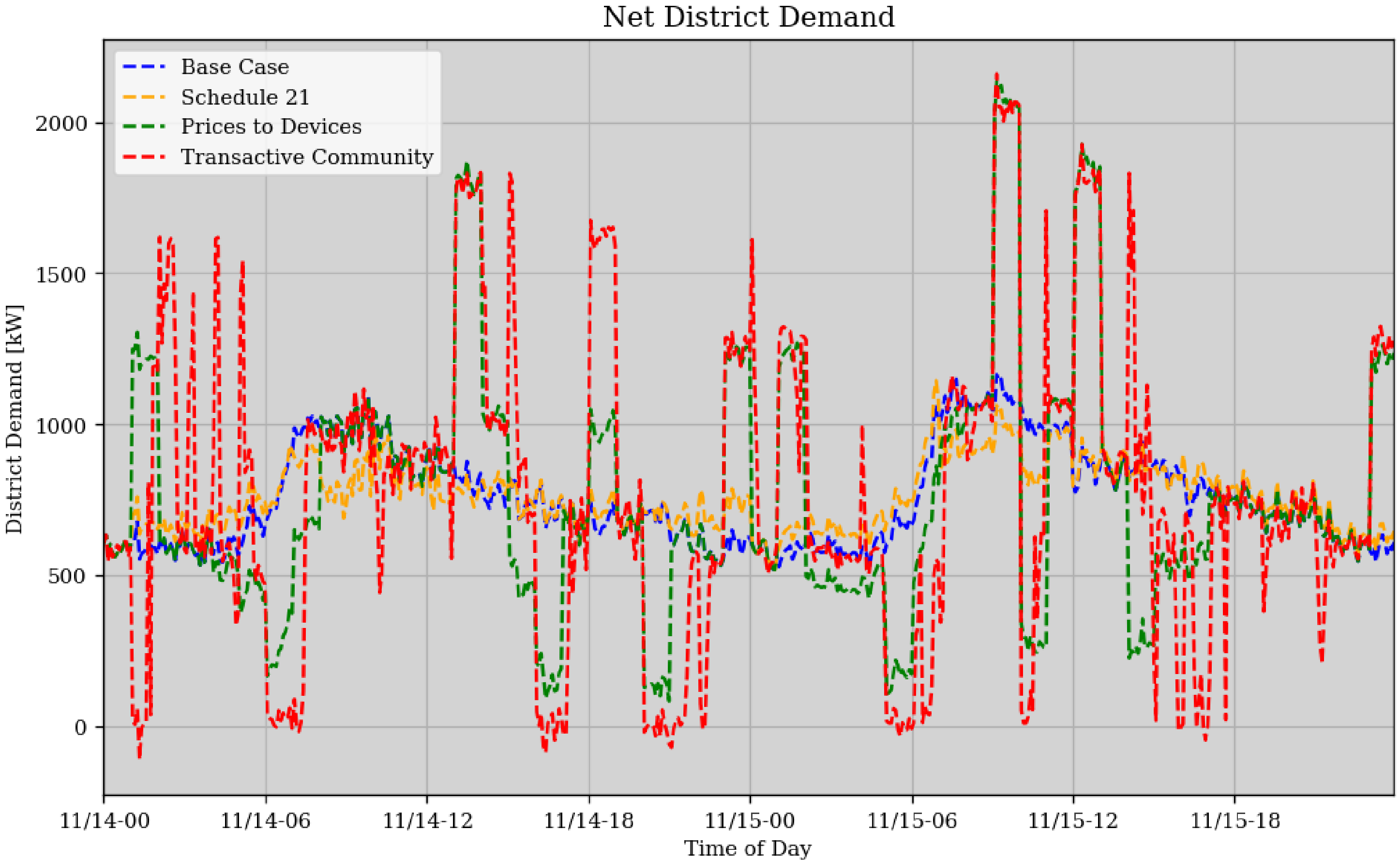
Transactive Coordination

When wholesale prices are volatile, the DERs can respond by lowering system demand and therefore prices for eachother





Transactive Coordination



Net Community Demand over 24h interval

Transactive Coordination

	Price Scenario	District 1	District 2	District 3	Total Cost
Base Case	Schedule 21	$2,802.38	$3,397.43	$2,447.91	$8,647.72
Case 1	Schedule 21	$2,679.96	$3,415.35	$2,437.17	$8,532.48
Case 2	Prices-to-Devices	$2,314.59	$3,357.54	$2,2547.28	$7,919.41
Case 3	Transactive	$2,277.54	$3,238.39	$2,161.48	$7,677.41

Resulting in a **12% reduction** in operating costs over 5-day interval

Future Work

- Plan to extend this work by implementing real-world on-site battery control field-testing.

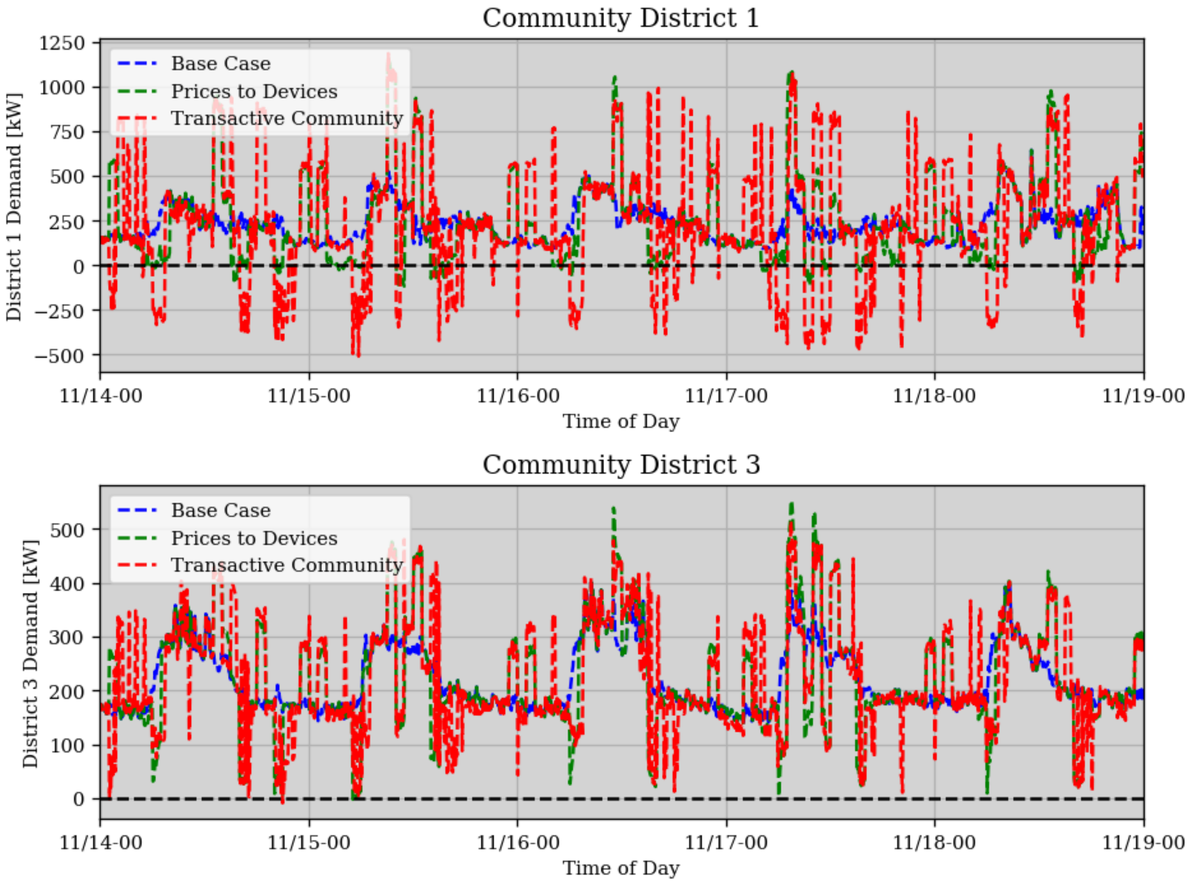
- Implement 3-phase power flow constraints into the community DER optimization formulations.

- Changes to agent objective functions can be extended to include other ancillary services (such as Volt-VAR support, spinning reserve, etc.).

Questions?

Transactive Coordination

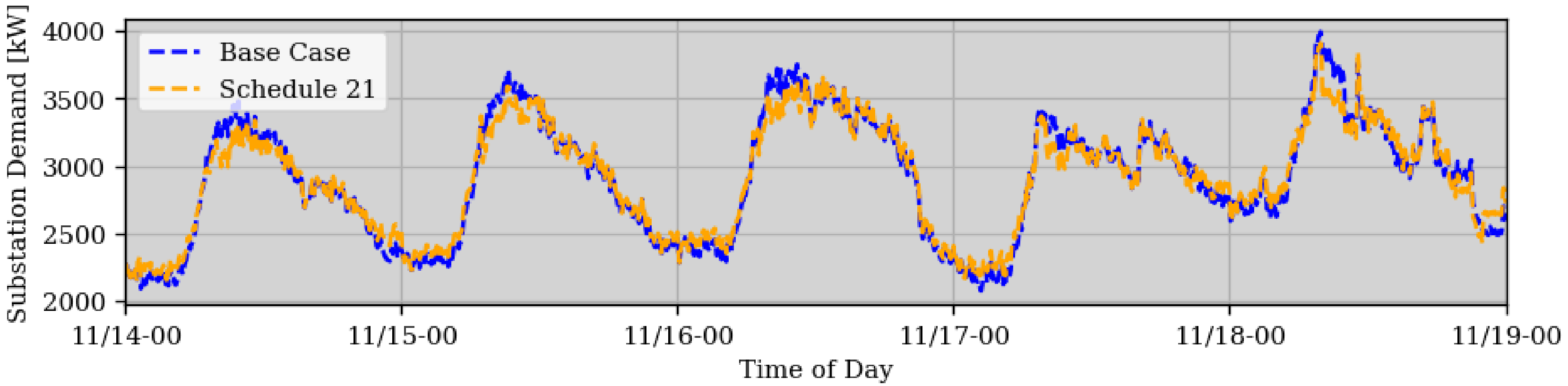
Community District 1 supports other two Communities with the larger DER asset profile



Community Demand over 5-day interval

Schedule 21 Pricing Scenario

$$\underset{Q^{j}_{c,t}}{\text{minimize}} \sum_{t=1}^{T} \left(\$0.753 \times Q^{j}_{c,t} + \frac{7}{30} Q^{j,max}_{c,t} \right)$$



Community District Optimization

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$$\underset{\hat{Q_{c,t}}}{\text{minimize}} \sum_{t=1}^{T}[P_t^{forecast} \times Q_{c,t}] \tag{1a}$$

$$Q_{c,t} = Q_{Load,t}^{forecast} + Q_{PV,t}^{forecast} + Q_{BESS,t} \tag{1b}$$

$$0 \leq Q_{BESS,t}^{+} \leq Q_{BESS,t}^{max,+} \quad \forall t = 1, ..., T \tag{1c}$$

$$0 \leq Q_{BESS,t}^{-} \leq Q_{BESS,t}^{max,-} \quad \forall t = 1, ..., T \tag{1d}$$

$$Q_{BESS,t} = Q_{BESS,t}^{+} - Q_{BESS,t}^{-} \quad \forall t = 1, ..., T \tag{1e}$$

$$q_{batt,t} = \frac{Q_{BESS,t}^{+}}{\eta^{+}} - Q_{BESS,t}^{-}\eta^{-} \quad \forall t = 1, ..., T \tag{1f}$$

$$l_t = l_{t-1} - \frac{1}{E_s} q_{batt,t}; \quad \underline{L_t} \leq l_t \leq \overline{L_t} \quad \forall t = 1, ..., T \tag{1g}$$

$$l_{desired} \leq l_T \tag{1h}$$

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