Eastern Interconnection Planning Collaborative

EIPC Gas-Electric System Interface Study: Results

Electric-Gas Coordination Working Group

May 19, 2015

LEVITAN & ASSOCIATES, INC.
MARKET DESIGN, ECONOMICS AND POWER SYSTEMS

Acknowledgement and Disclaimer

The EIPC appreciates and acknowledges the support of DOE for the Eastern Interconnection Studies Project

Acknowledgement:

- This material is based upon work supported by the Department of Energy, National Energy Technology Laboratory, under Award Number DE-OE0000343.

Overview

- Study Highlights
- Target 1: Existing Gas Infrastructure Baseline Assessment
- Target 2: Infrastructure Adequacy Analysis
- Target 3: Contingency Analysis
- Target 4: Fuel Assurance Analysis

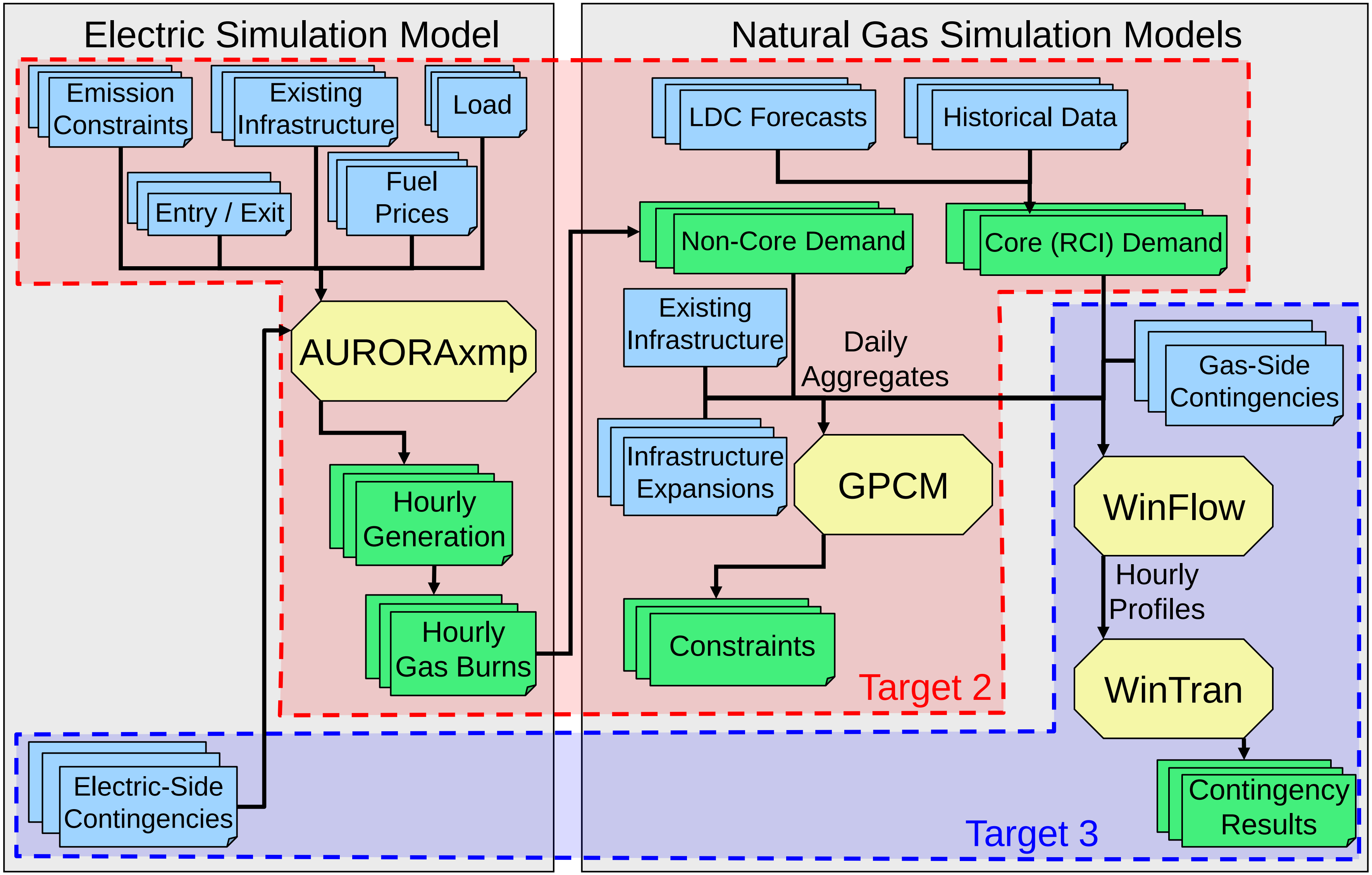
Study Highlights

- Character of service: Most generators do not hold firm transportation entitlements, except in TVA and Ontario
- Gas infrastructure adequacy analysis: Constraints affect generation in ISO-NE, NYISO, EMAAC and SWMAAC
- Contingency analysis: Most gas contingencies allow time for PPAs to schedule alternative resources
- Fuel assurance: Dual-fuel capability less expensive than incremental FT in almost all cases

Study Overview – Four Targets

- Target 1: Develop baseline assessment of natural gas-electric system interfaces, interaction effects, and the current level of coordination between the electric and gas systems
- Target 2: Evaluate gas infrastructure capability to supply the electric power sector in 2018 and 2023 (Winter and Summer) while serving higher priority RCI loads
- Target 3: Identify impact of postulated gas and electric contingencies on sustainability of gas-fired generation
- Target 4: Review operational / planning / economic issues related to fuel assurance through dual-fuel capability and incremental FT

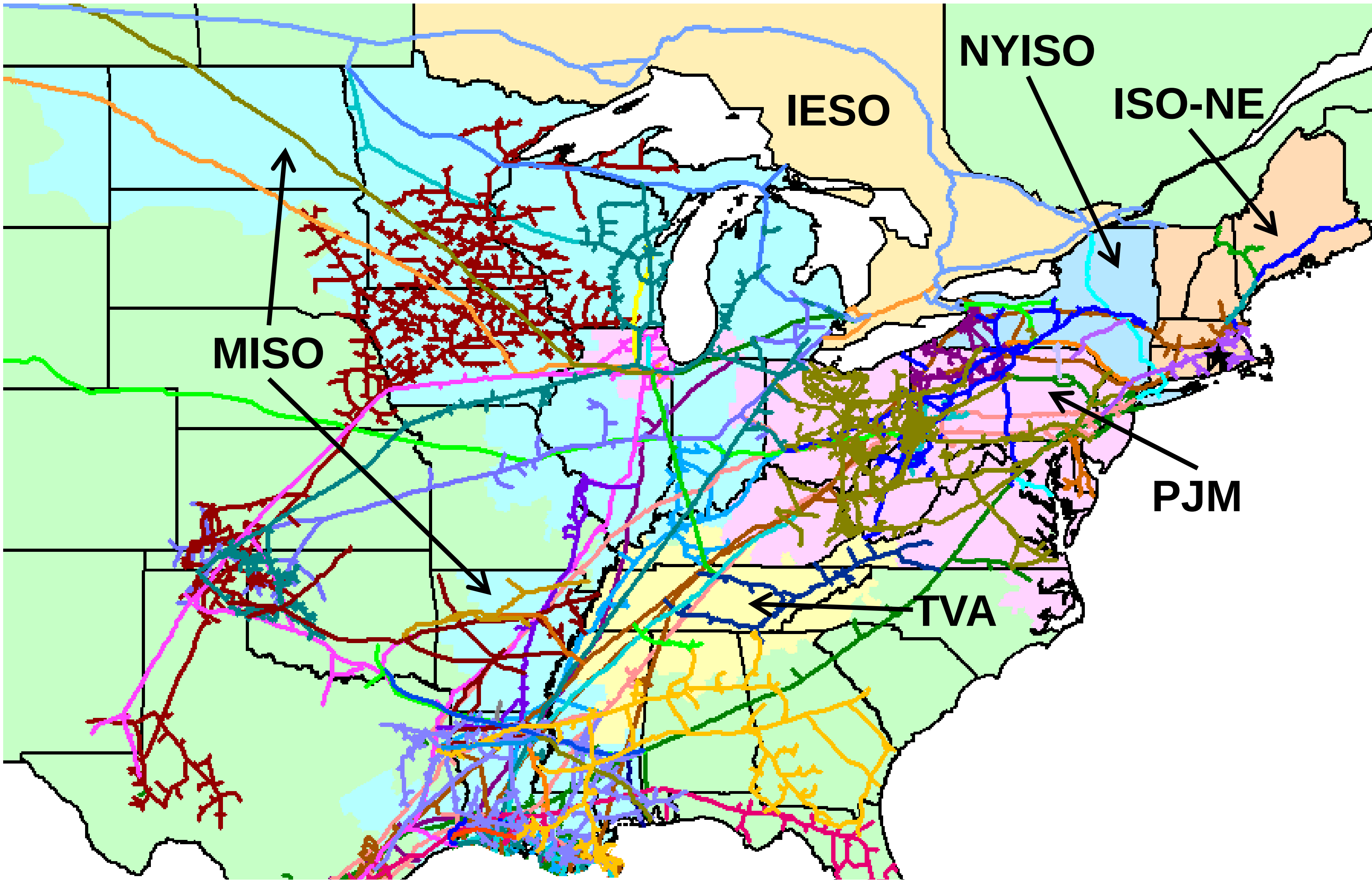
Model Framework



Target 1

Existing Natural Gas-Electric System Interfaces

PPAs and Study Region Pipelines



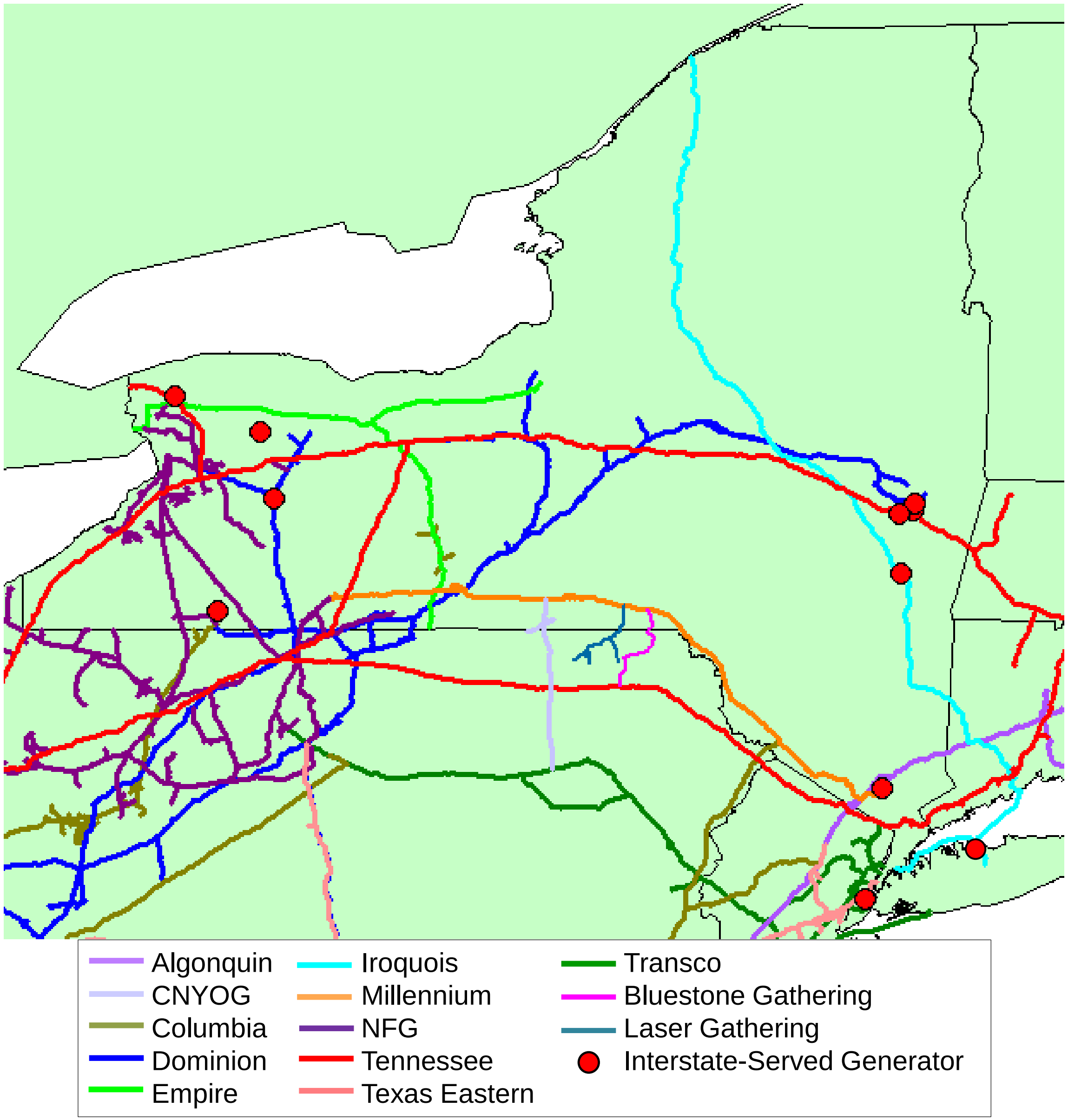
Study Region Gas Infrastructure

- 61 interstate pipelines + 1 interprovincial pipeline
- 10 intrastate pipelines and 75 LDCs serve generators >15 MW
- 321 conventional underground storage facilities
- 10 LNG import terminals
- 78 LNG storage/peak shaving facilities

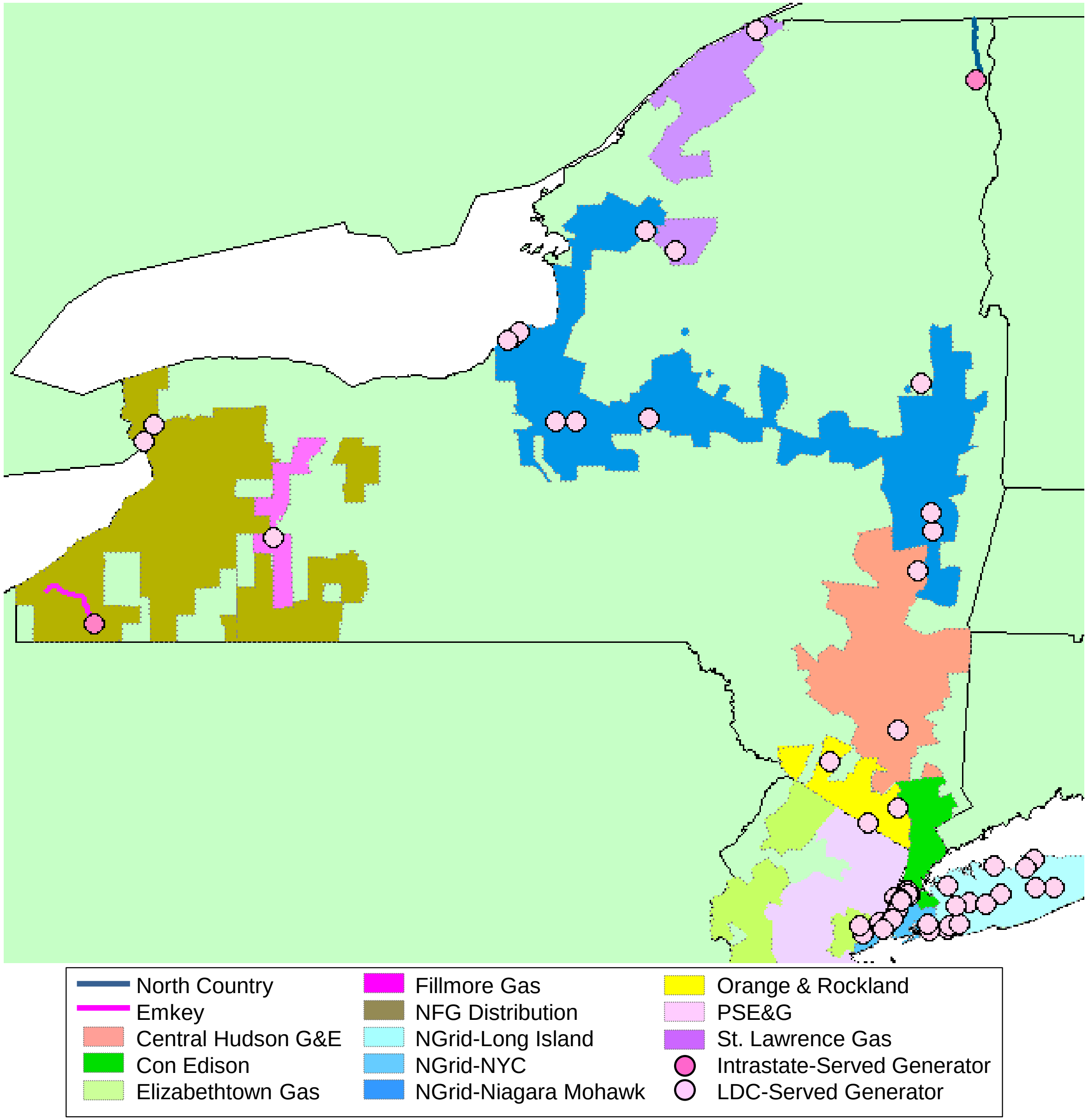
NYISO Gas Infrastructure

- 11 interstate pipelines
- 2 intrastate pipelines and 7 LDCs serve generators >15 MW
- 26 conventional underground storage facilities in upstate New York
- 3 LNG storage facilities supporting the New York Facilities System
- 2 non-FERC jurisdictional production/gathering systems

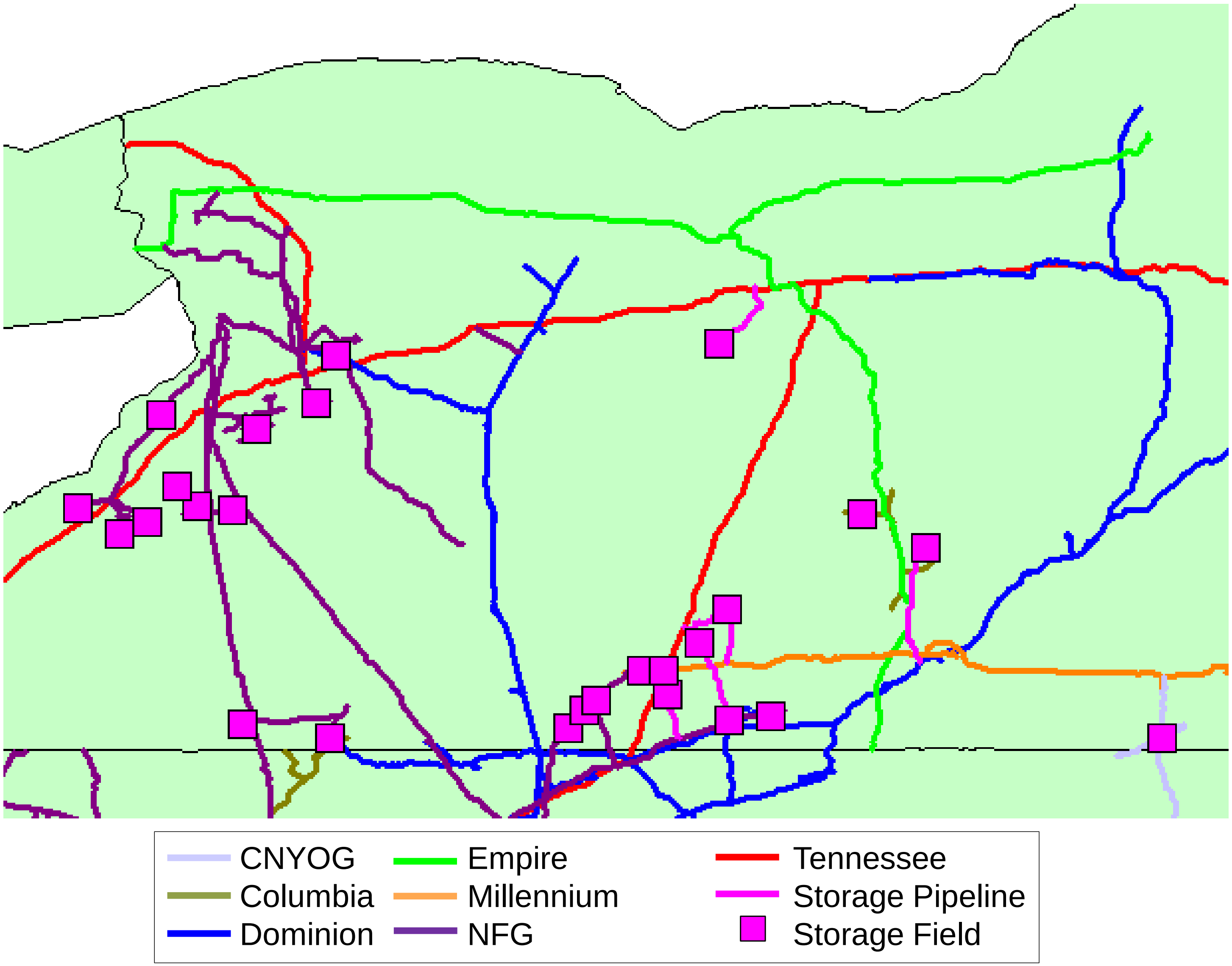
Pipelines Directly Serving NYISO Generation



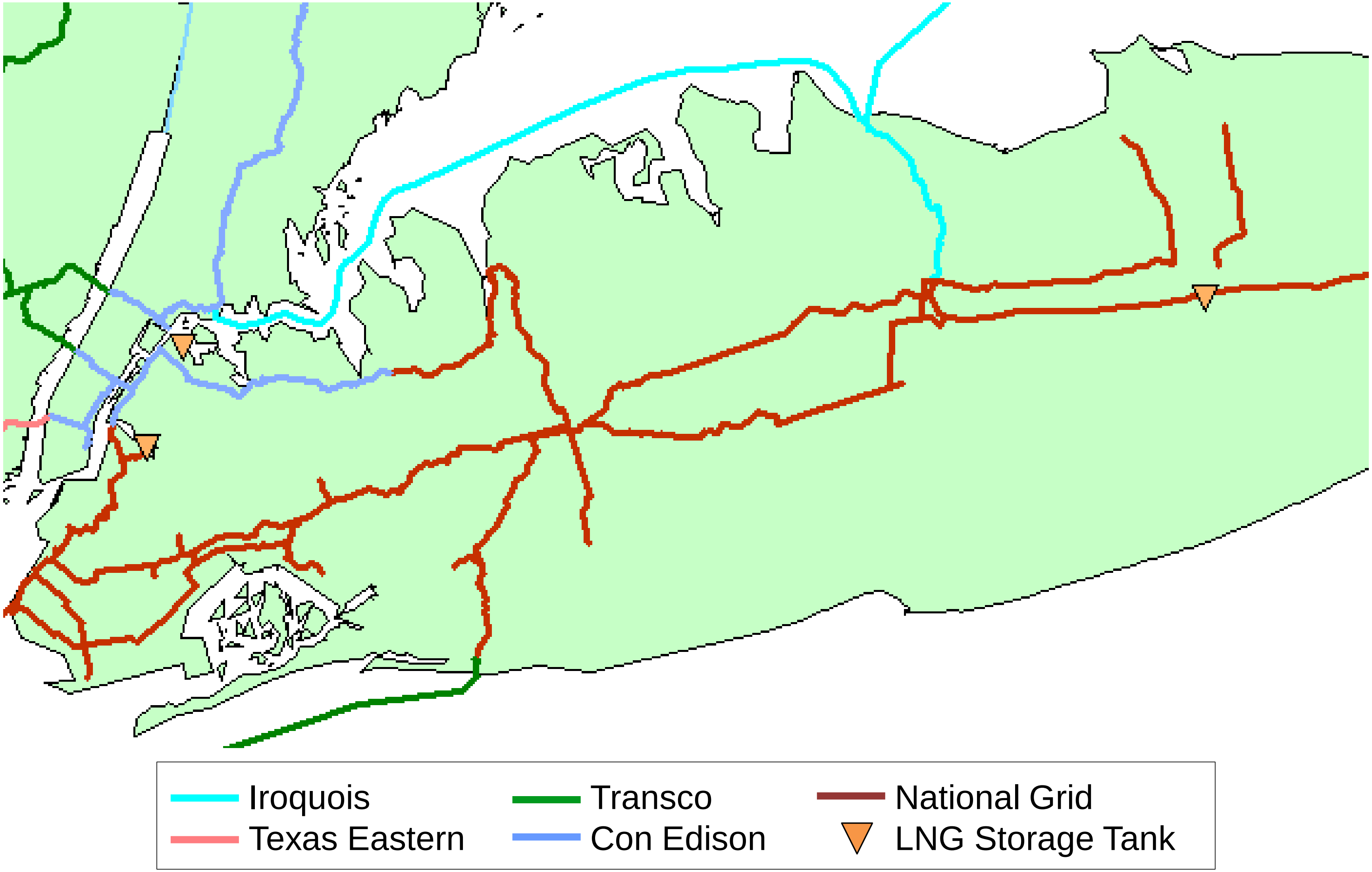
LDCs Serving NYISO Generation



Underground Storage Facilities in NYISO



LNG Facilities in NYISO



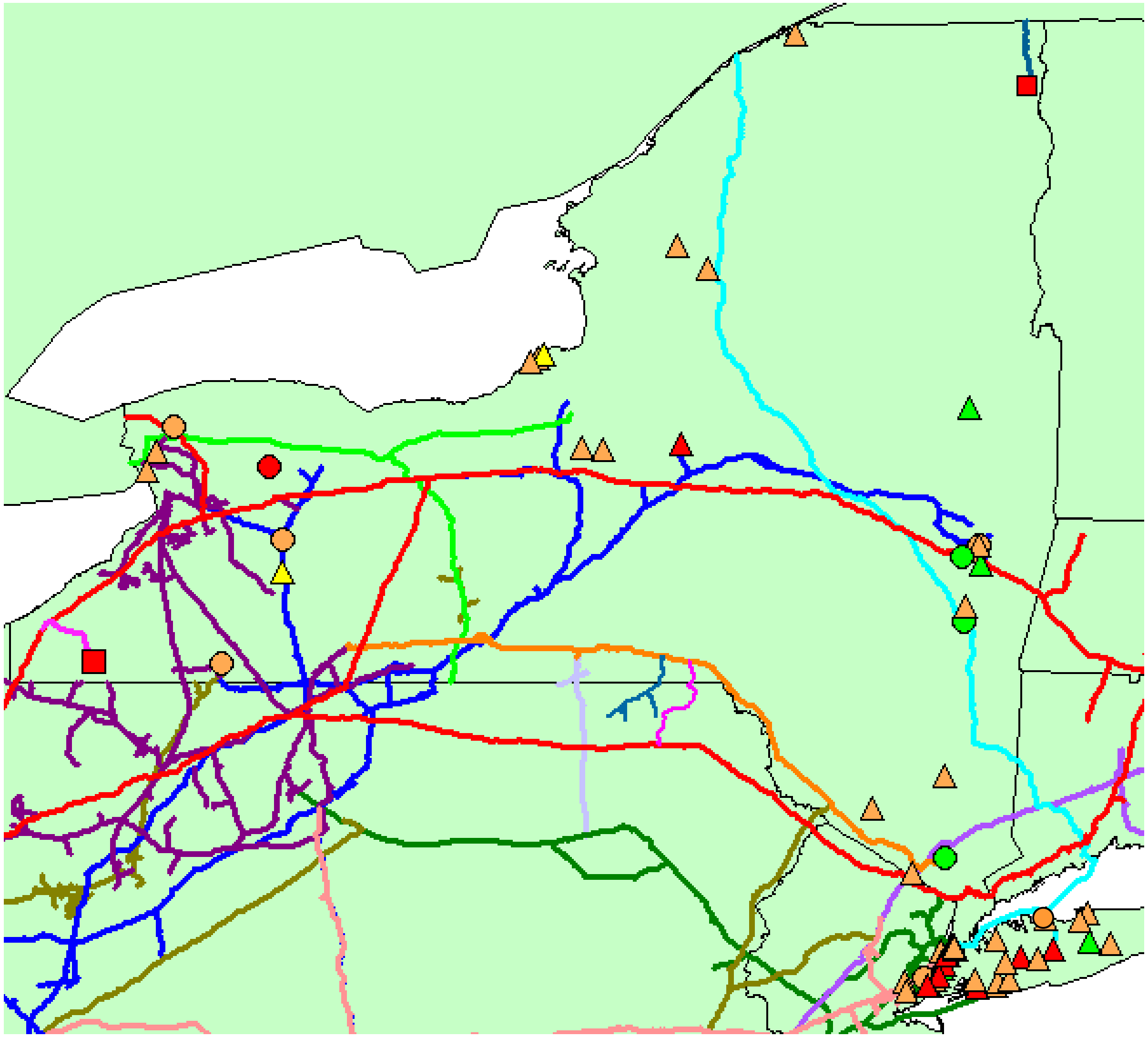
EIPC Eastern Interconnection Planning Collaborative

LEVITAN & ASSOCIATES, INC.

NYISO Generator Contracting Practices

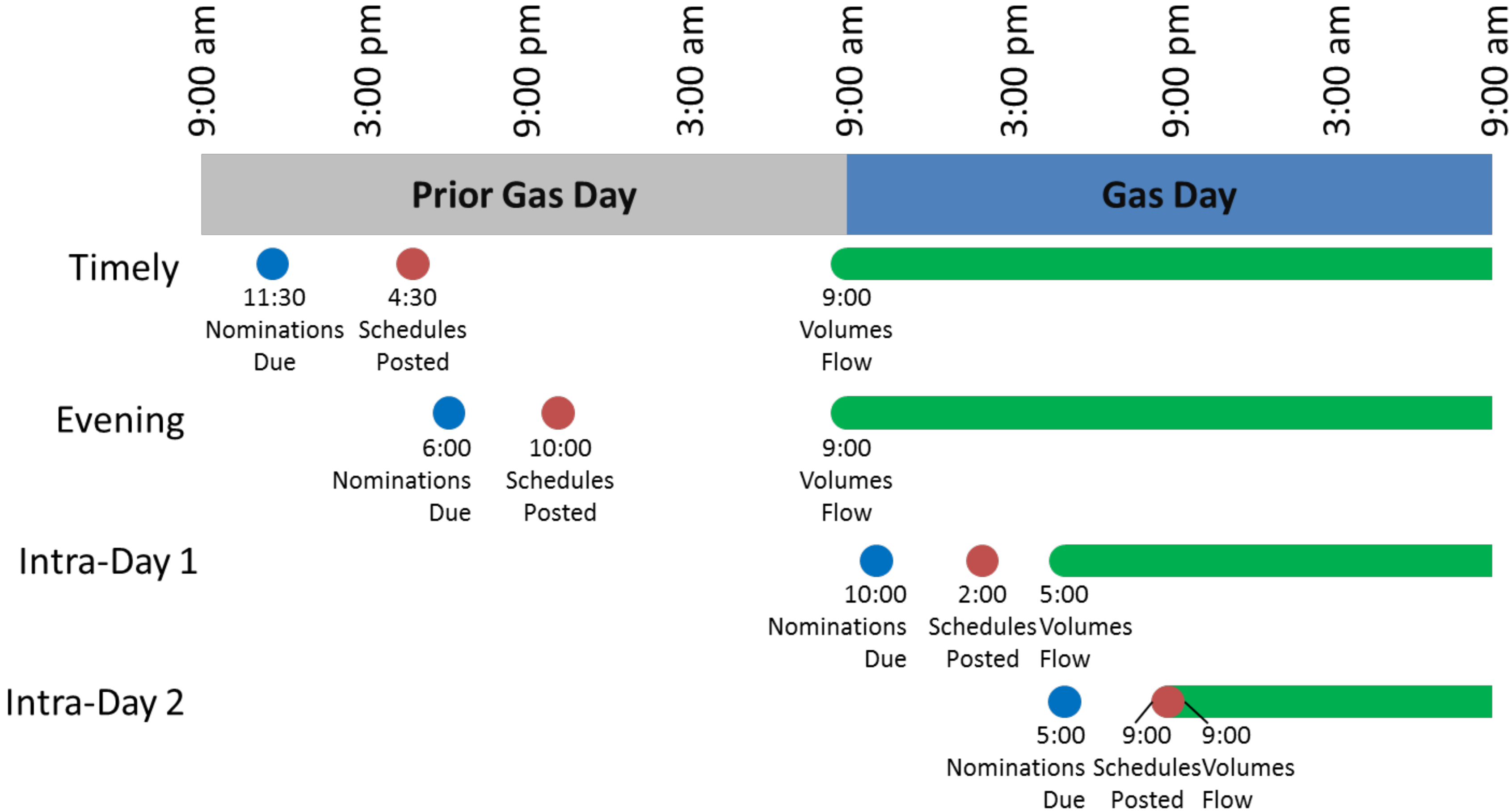
- Large majority of NY generators do not have FT
- NY LDCs offer IT service under negotiated rate schedules
- NY LDCs require dual fuel capability for generators taking non-firm service
- A few generators have FT rights for a portion of their fuel requirements
- Con Edison and NGrid are active assignors in the capacity release market, primarily on Transco and Texas Eastern
- Capacity releases are short-term and are subject to recall
- Use of Asset Management Agreements is common

NYISO Generator Contracting Practices



	Mainline Contract	Dual-Fuel Capable
●	Yes	Yes
●	Yes	No
●	No	Yes
●	No	No

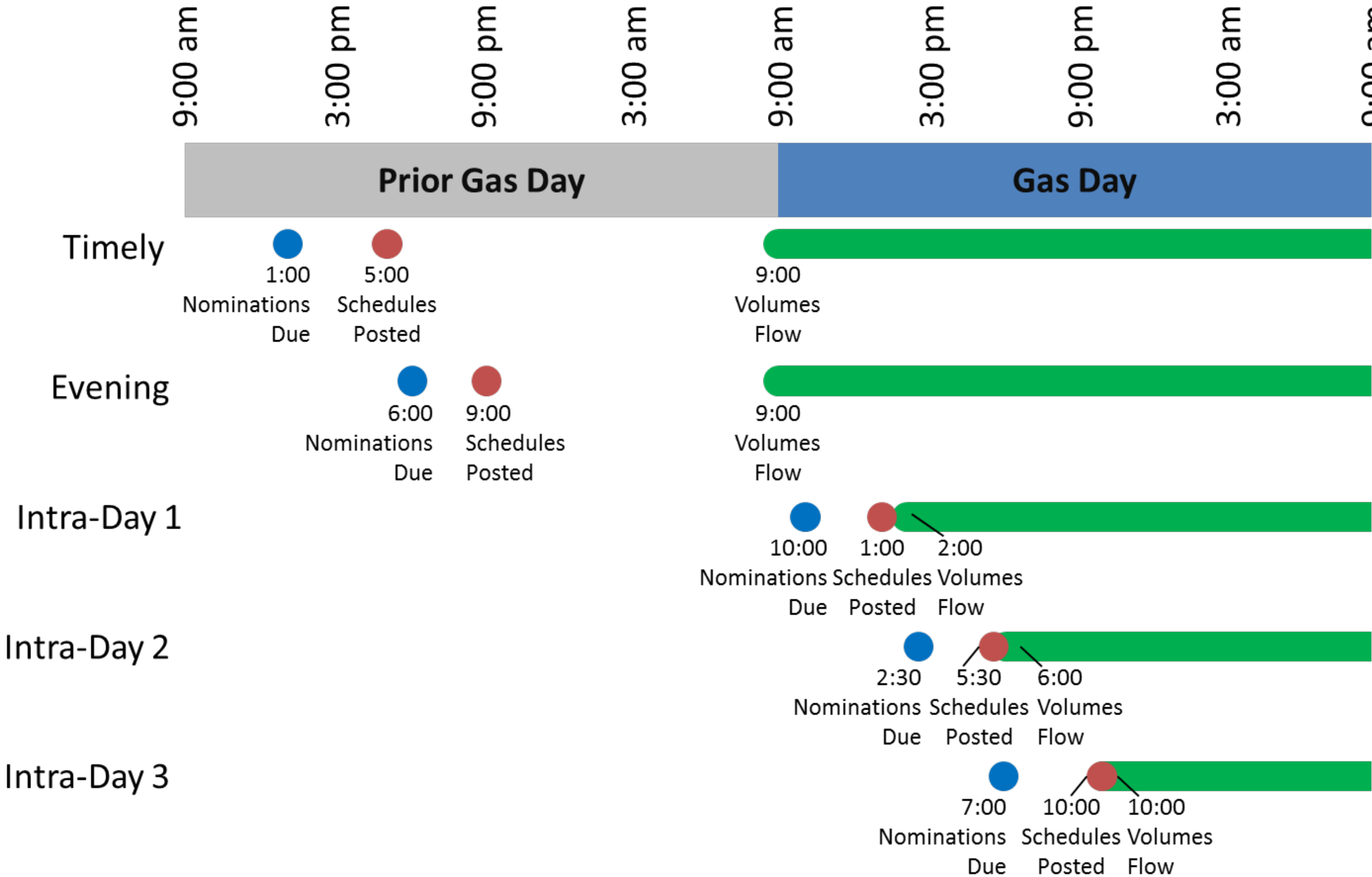
Current NAESB Nomination Cycles



FERC Order No. 809

- Gas Day start time not changed
- Timely Cycle nomination deadline pushed back
- Third Intraday Cycle added
- Pipelines required to make multi-party FT contracts available if requested by a shipper
- April 1, 2016 deadline to comply with revised NAESB standards

Revised NAESB Nomination Cycles



Gas-Electric Interface Attributes

	Criterion	NYISO	IESO	ISO-NE	MISO	PJM	TVA
Natural Gas Supply	Gas Supply Portfolio Diversity						
	Pipeline Connectivity						
	Conventional Storage Deliverability						
	LNG Storage Capability						
Electric-Gas Interface	Firm Transportation Entitlements						
	Direct Pipeline Connectivity						
Electric-Gas Tariff	Pipeline or LDC Penalties						
	LDC Provision of Flexible Service						
	Active Secondary Market						

Legend	Favorable Relative to Other PPAs	Neutral	Unfavorable Relative to Other PPAs

Qualitative Assessment – Electric-Gas Tariff

Criterion	NYISO	IESO	ISO-NE	MISO	PJM	TVA
Pipeline or LDC Penalties						

- Pipeline and LDC penalty provisions safeguard against scheduling conduct that harms system integrity or degrades service to firm customers
- Tariffs require uniform hourly flows and adherence to scheduled quantities
  - Flexibility during normal operating conditions
  - Significant penalties during critical notices incl. OFOs

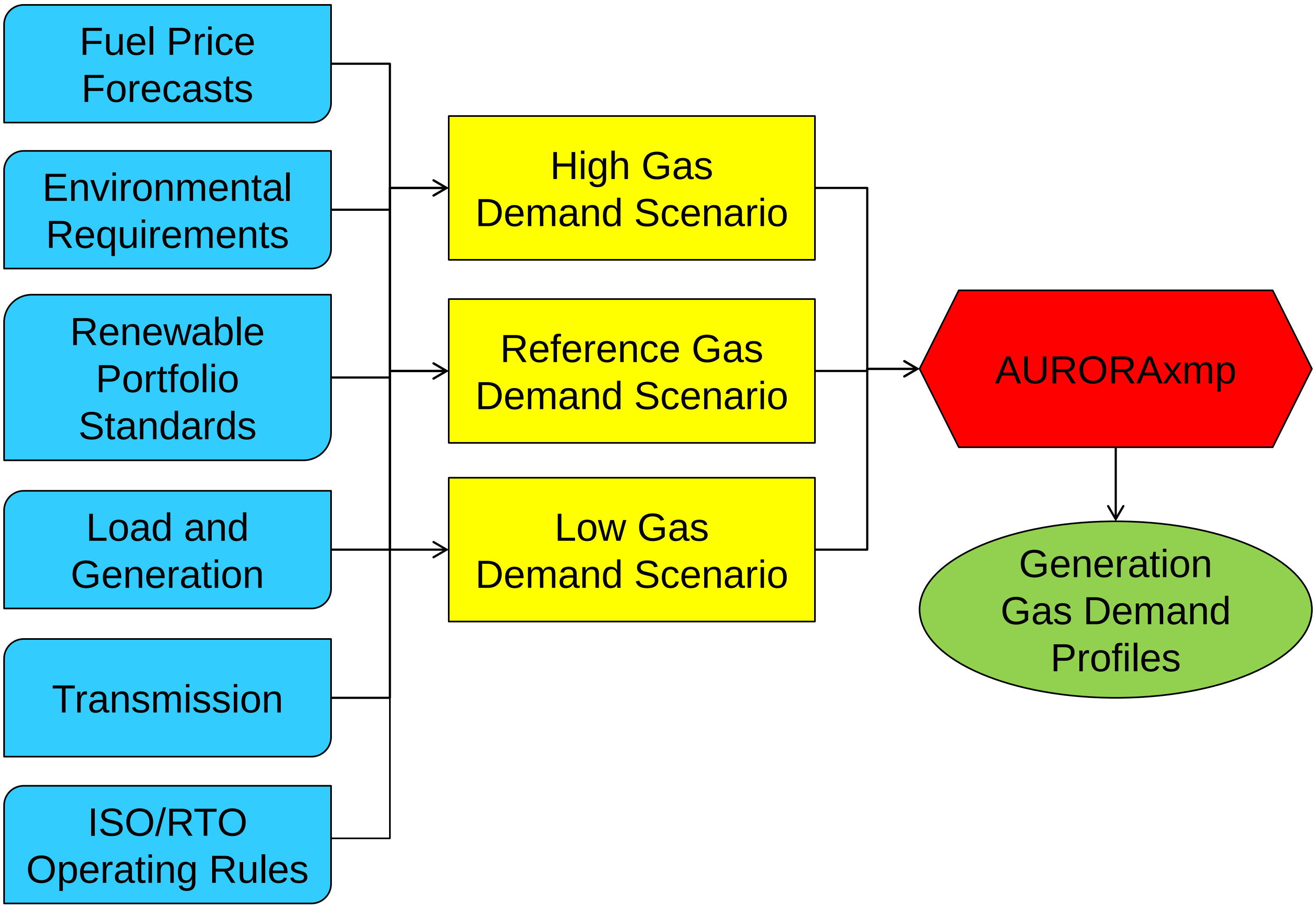
Target 2

Natural Gas Infrastructure Adequacy to Serve Electric System Demand

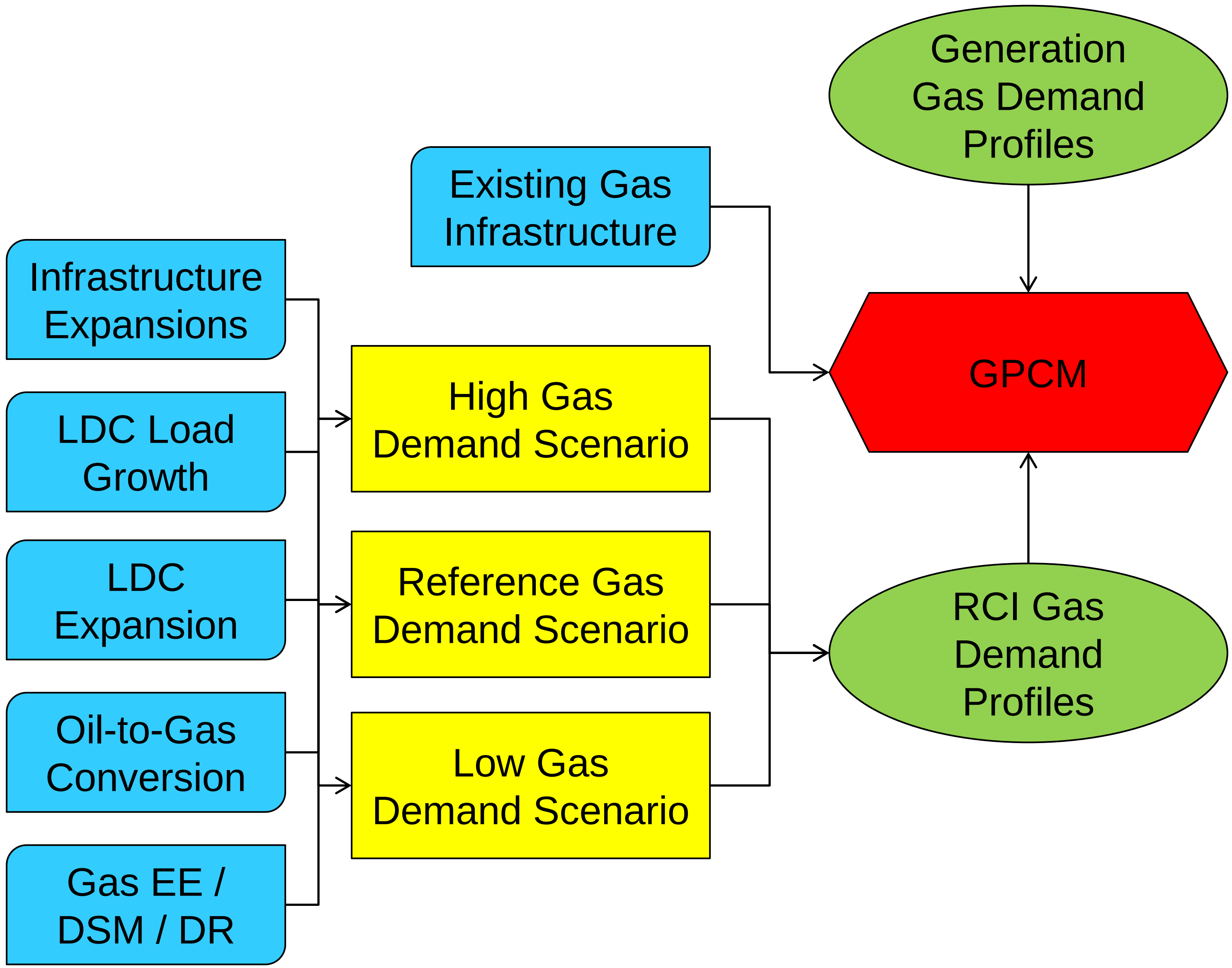
Constraint Identification Approach

- Develop electric system dispatch model for 2018 and 2023 (Winter & Summer) to estimate hourly gas demands for each generator
- Combine forecasts of RCI and generator gas demand to represent seasonal coincident peak days
- Quantify unserved gas demand using optimization modeling of the gas infrastructure network for seasonal peak hours, and allocate the unserved demand to affected generators
- Quantify frequency and duration (F-D) of pipeline constraints during seasonal daily peak hours
- Identify gas transportation constraints causing unserved peak hour demand
- Identify potential mitigation measures to reduce or eliminate transportation constraints affecting generation

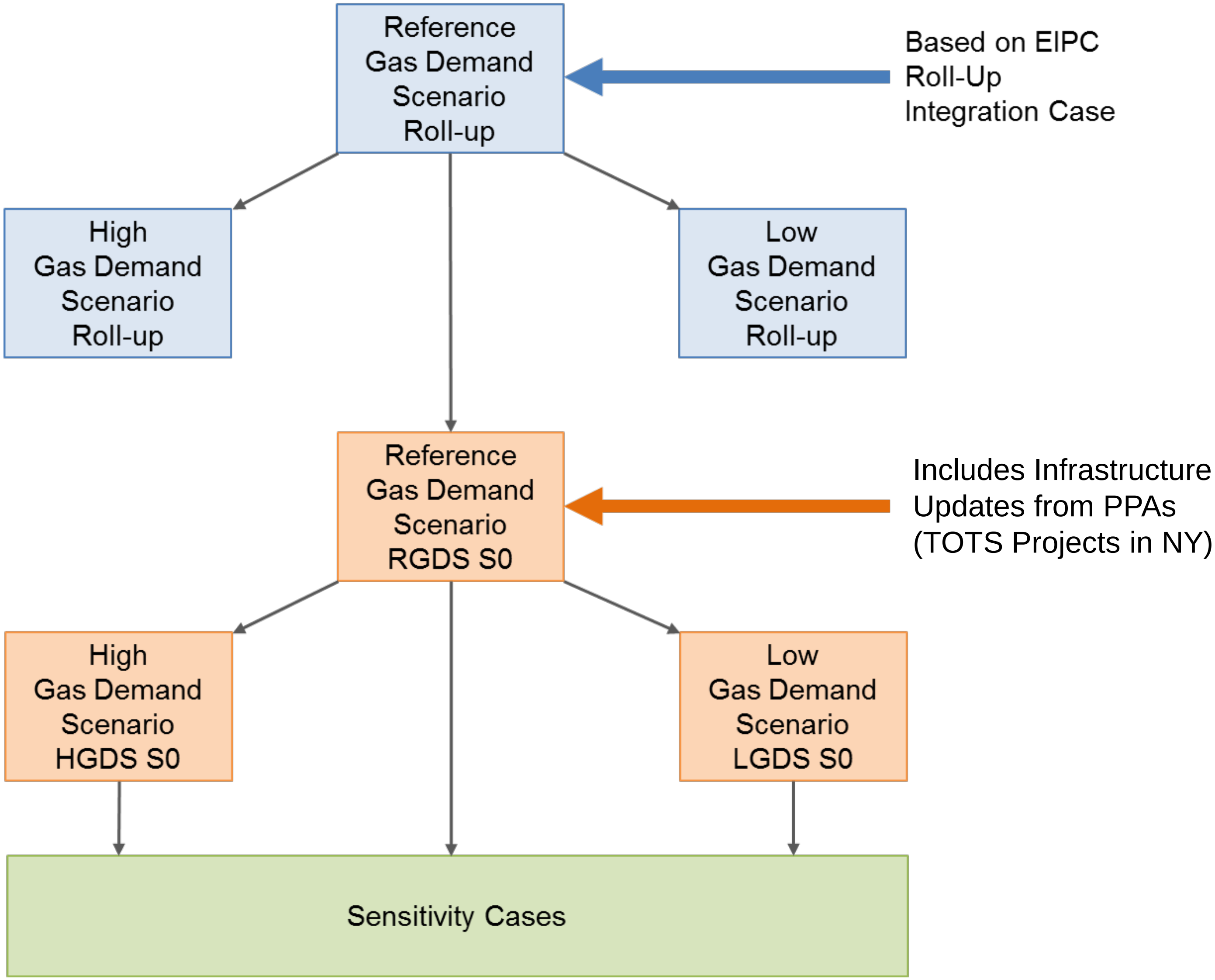
Modeling Systems Overview – Electric-Side



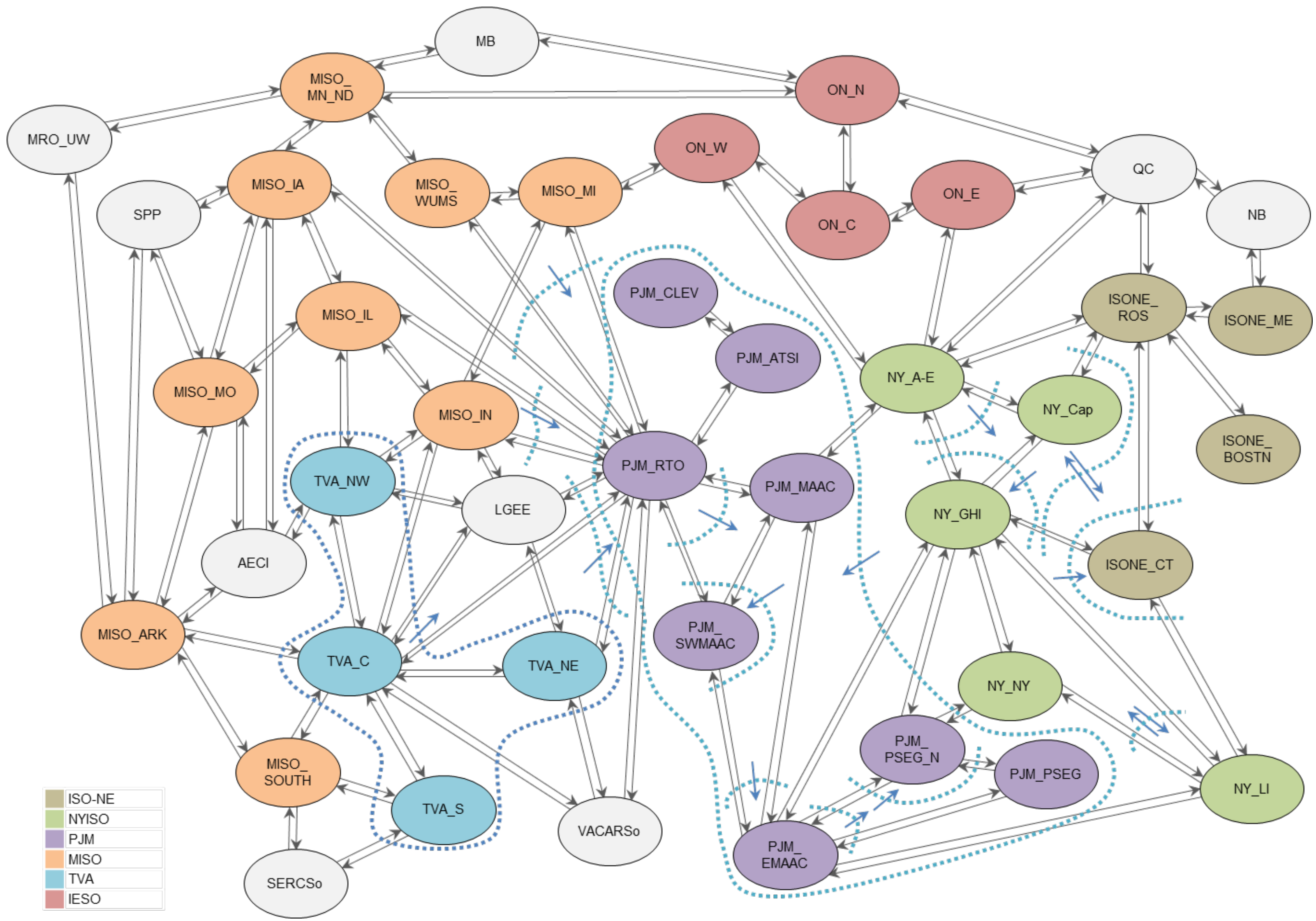
Modeling System Overview – Gas-Side



Scenarios and Sensitivities



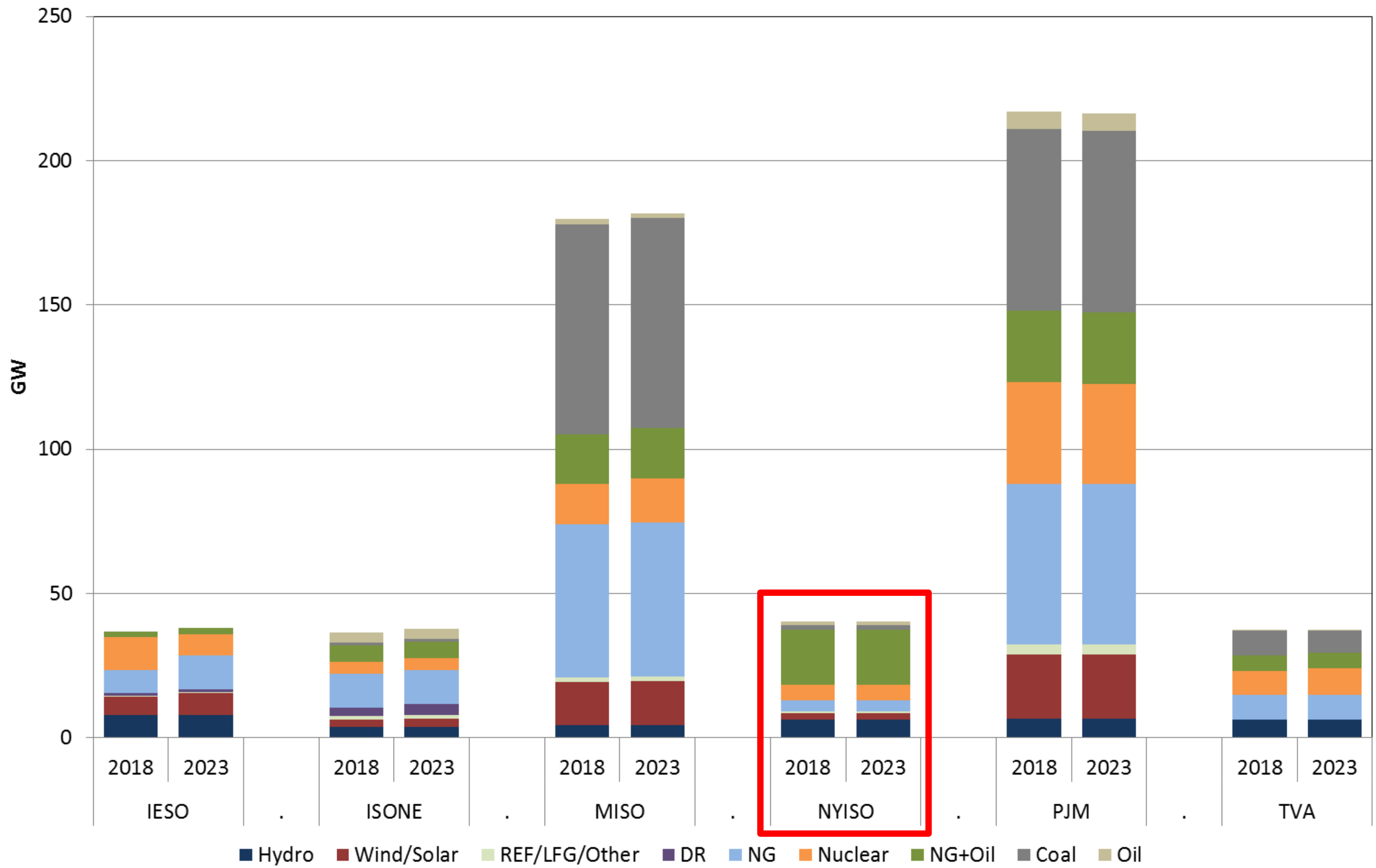
Transmission Topology



EIPC Eastern Interconnection Planning Collaborative

LEVITAN & ASSOCIATES, INC.

RGDS S0 Resource Mix



EIPC Eastern Interconnection Planning Collaborative

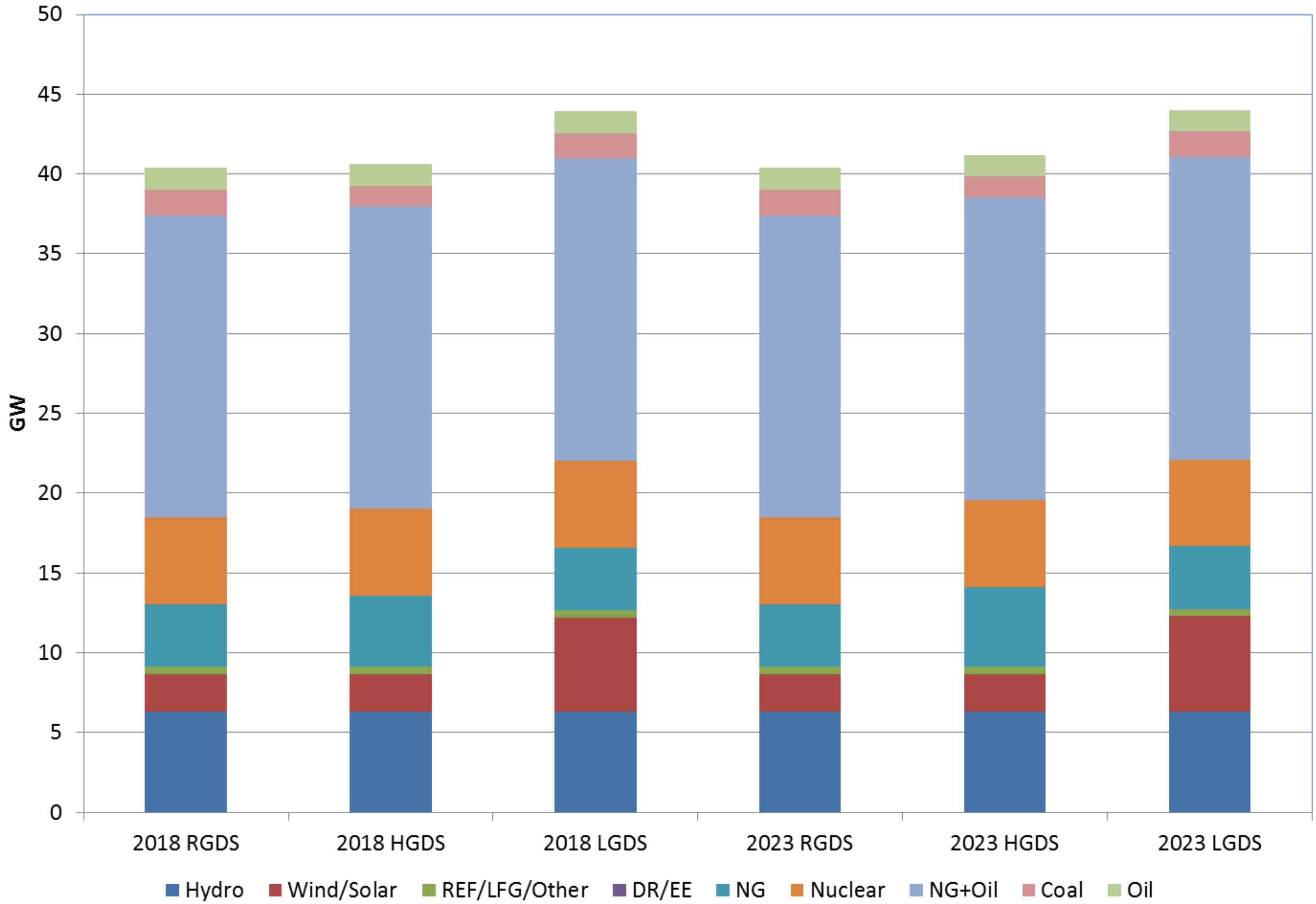
LEVITAN & ASSOCIATES, INC.

HGDS and LGDS Resource Mix Definition

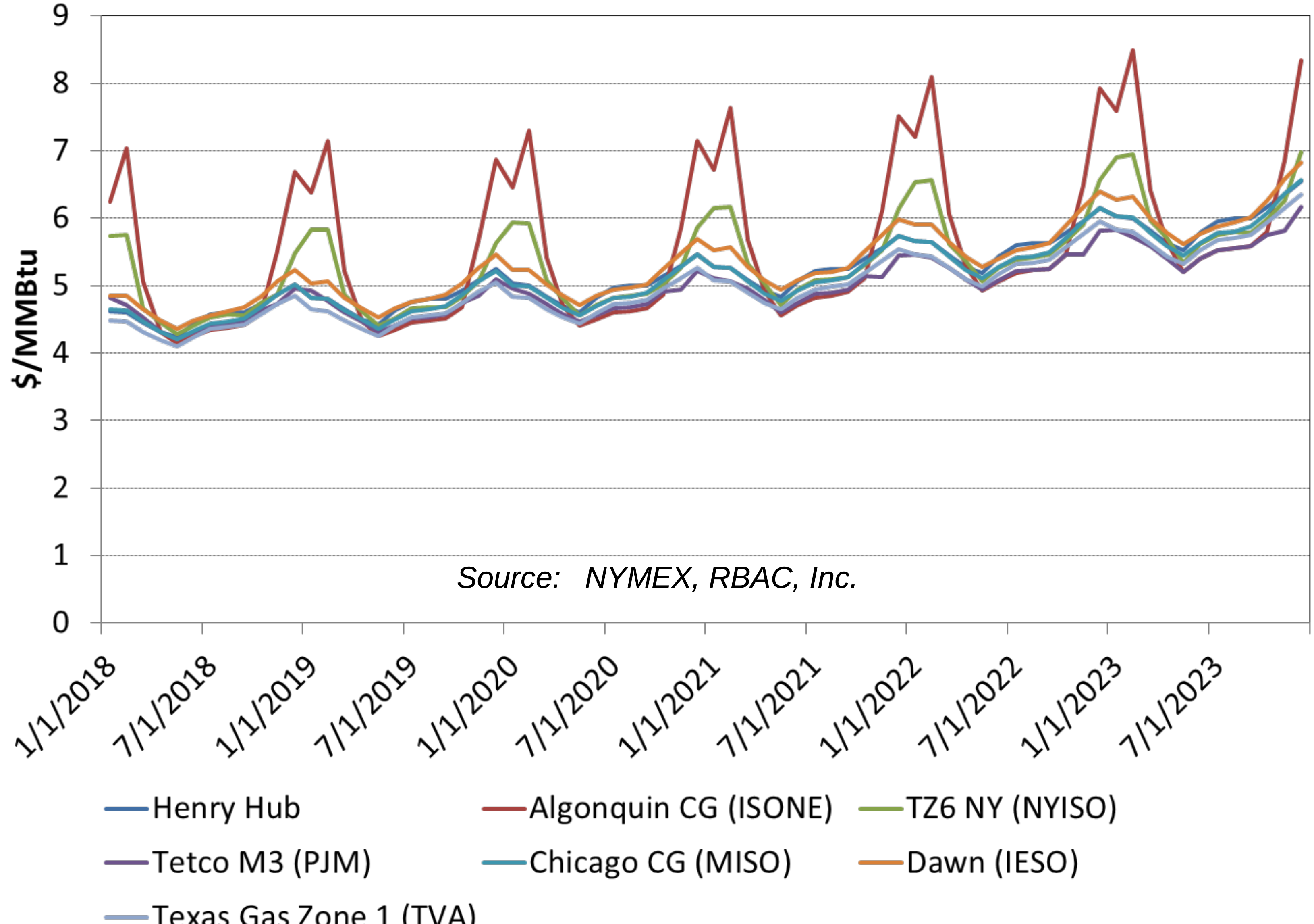
- High Gas Demand Scenario
  - Increased attrition of selected coal, oil and nuclear units, replaced by new gas-fired units
  - "At-risk" units identified by PPAs or selected based on published reports on potential coal retirements

- Low Gas Demand Scenario
  - Increased penetration of renewables and EE/DR
  - Primarily onshore wind added to meet RPS targets and 50% of non-binding renewable targets
  - Solar PV added where required by RPS targets
  - Lower electric load forecast reflects additional EE/DR

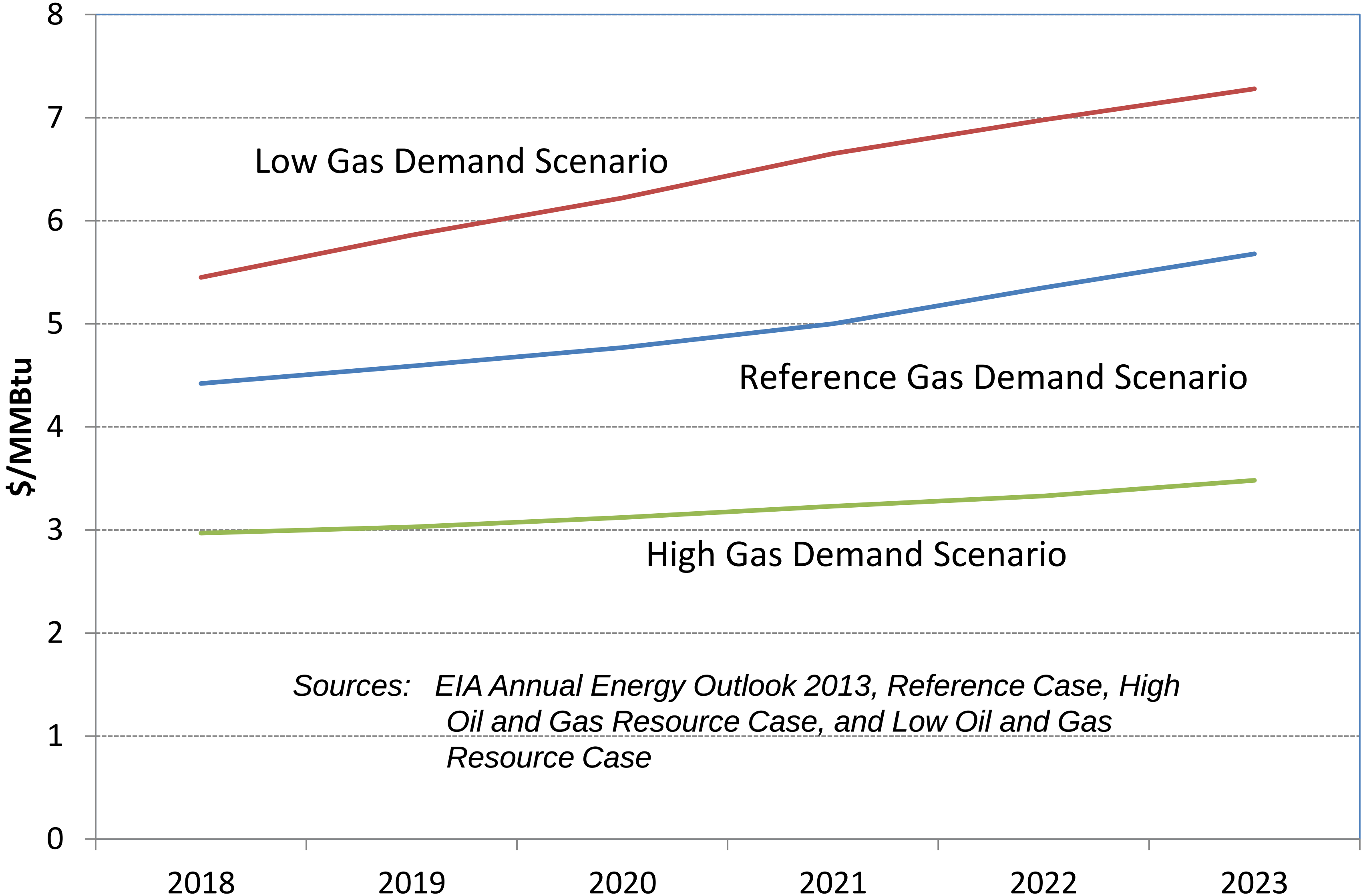
NYISO Resources by Scenario and Year



Gas Price Forecast at Representative Points



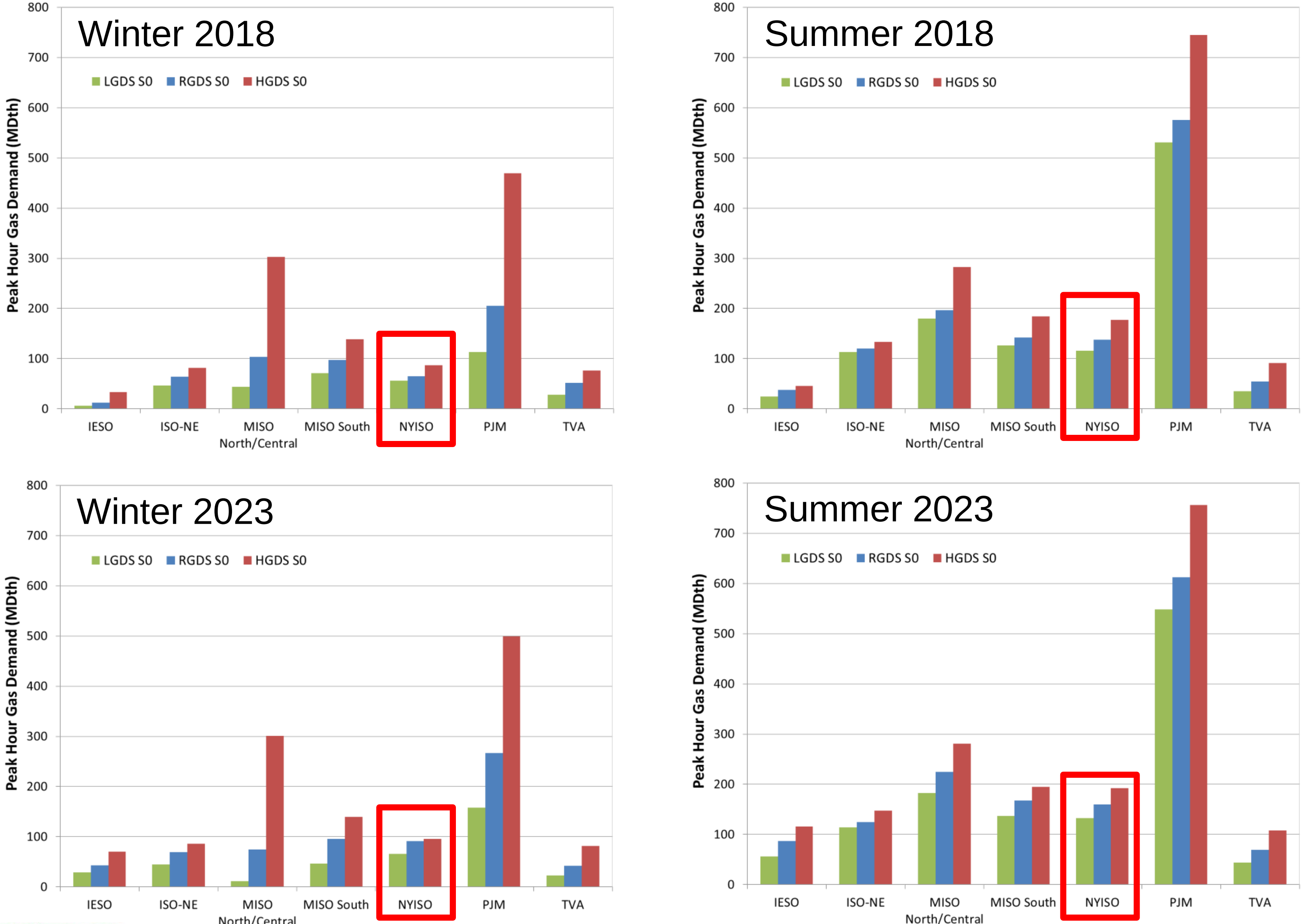
Gas Price Forecast (Henry Hub)



Environmental Assumptions

- Assume that retirement of coal- and oil-fired units in US reflects economic decisions driven by environmental requirements, including MATS, Clean Water Act 316(b), NAAQS, Coal Combustion Residual Rule, Regional Haze, Clean Air Act 111(d), etc.
  - No financial analysis of specific plants was conducted
- SO_2, NO_x emission allowance prices remain at current CAIR levels; assume no significant change under CSAPR
- CO_2 emission allowance prices remain consistent with current RGGI program; no change or expansion of footprint

Electric Sector Peak Hour Gas Demand



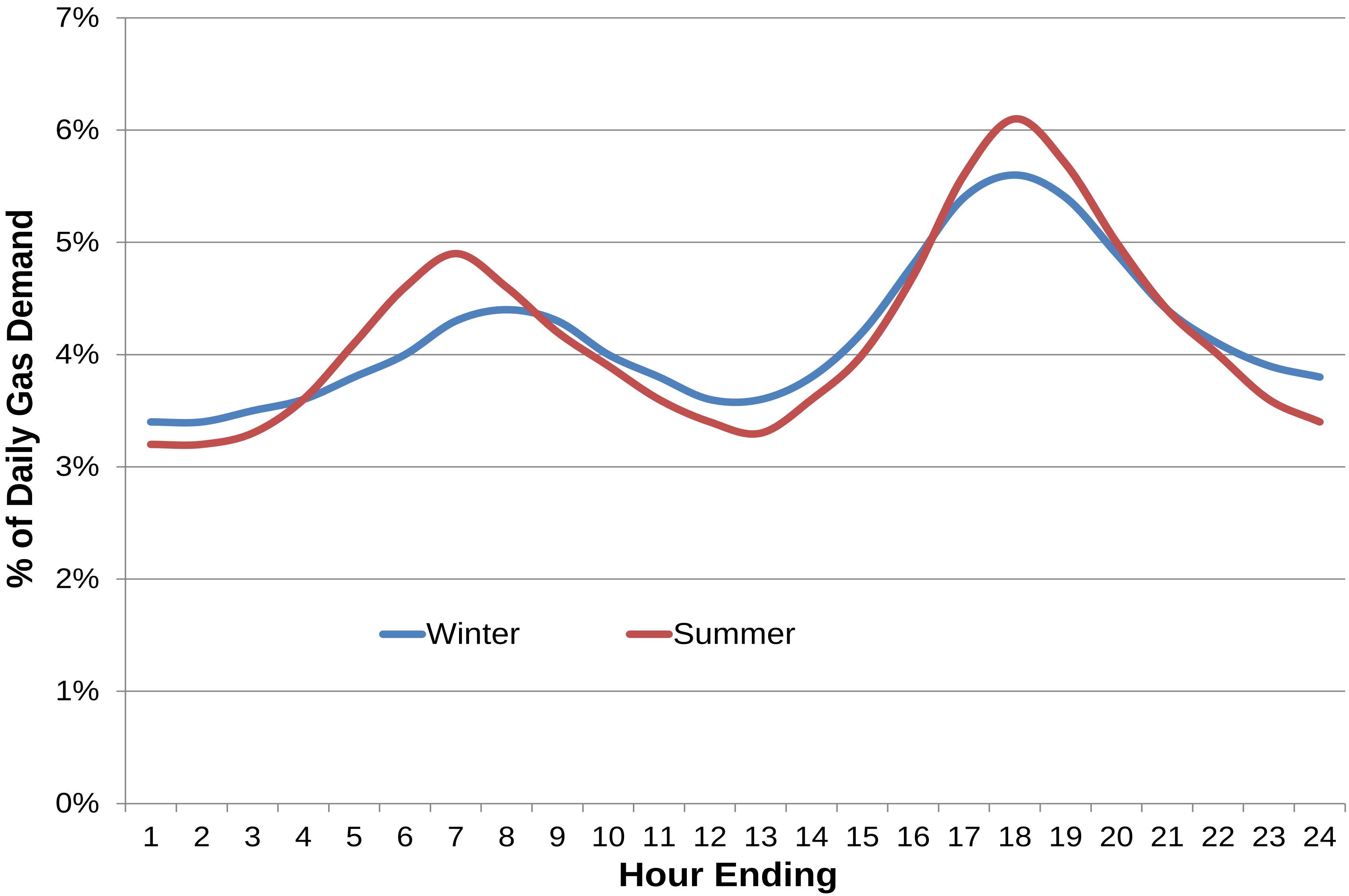
EIPC
Eastern Interconnection Planning Collaborative

LEVITAN & ASSOCIATES, INC.

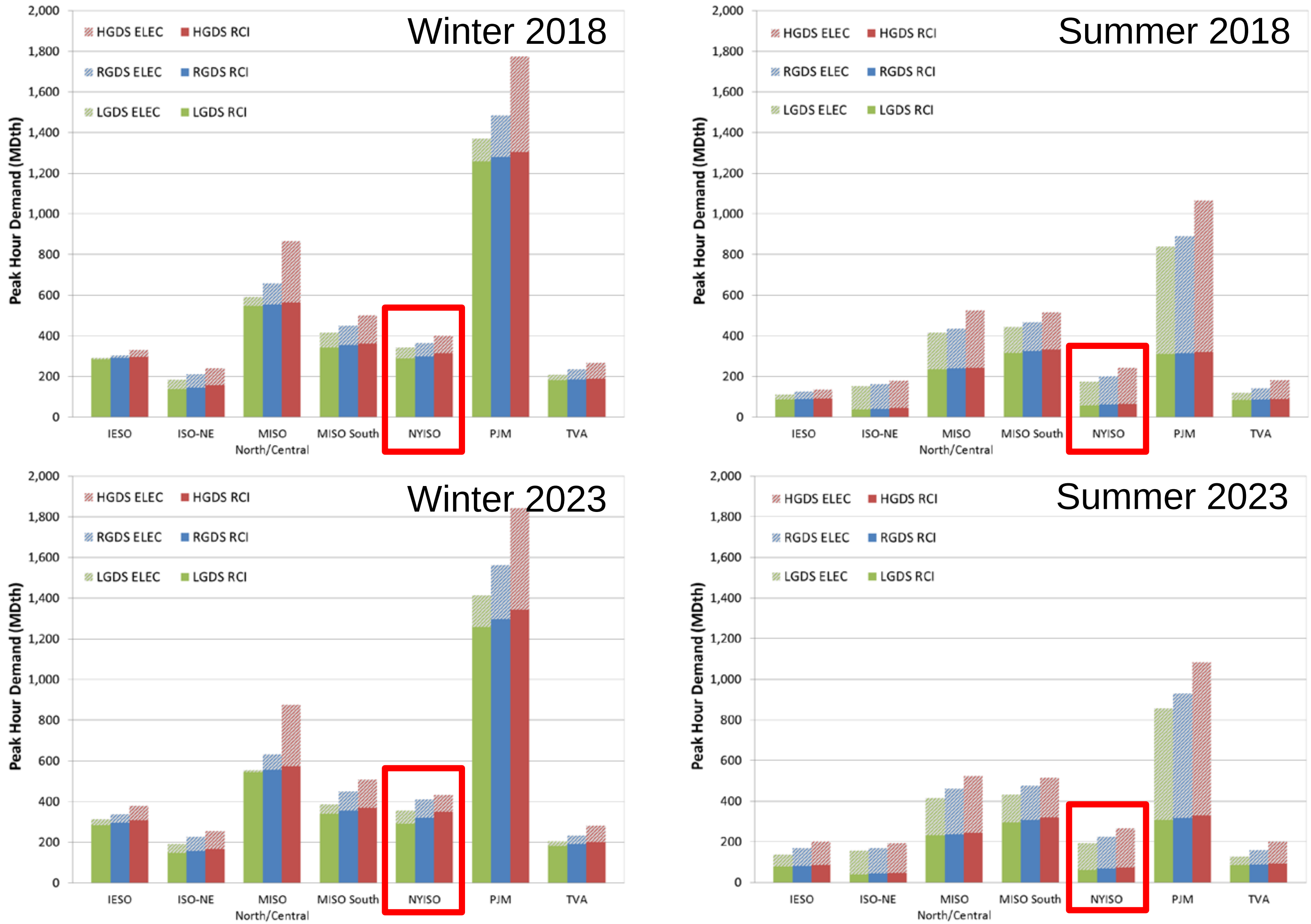
RCI Demand Forecast Development

- Based on historical data and published LDC forecasts
  - NYISO: 2013-14 Winter Supply Review (NYPSC Case No. 13-G-0206)
- Adjustment to coincident peak day values
  - Scaled by ratio of demand on Study Region coincident peak day to non-coincident peak demand
- Peak hour construct used to test infrastructure against maximum coincident requirements
  - Peak hour generation demand extracted from Aurora
  - Seasonal intraday peak hour percentage of daily demand applied to RCI forecasts

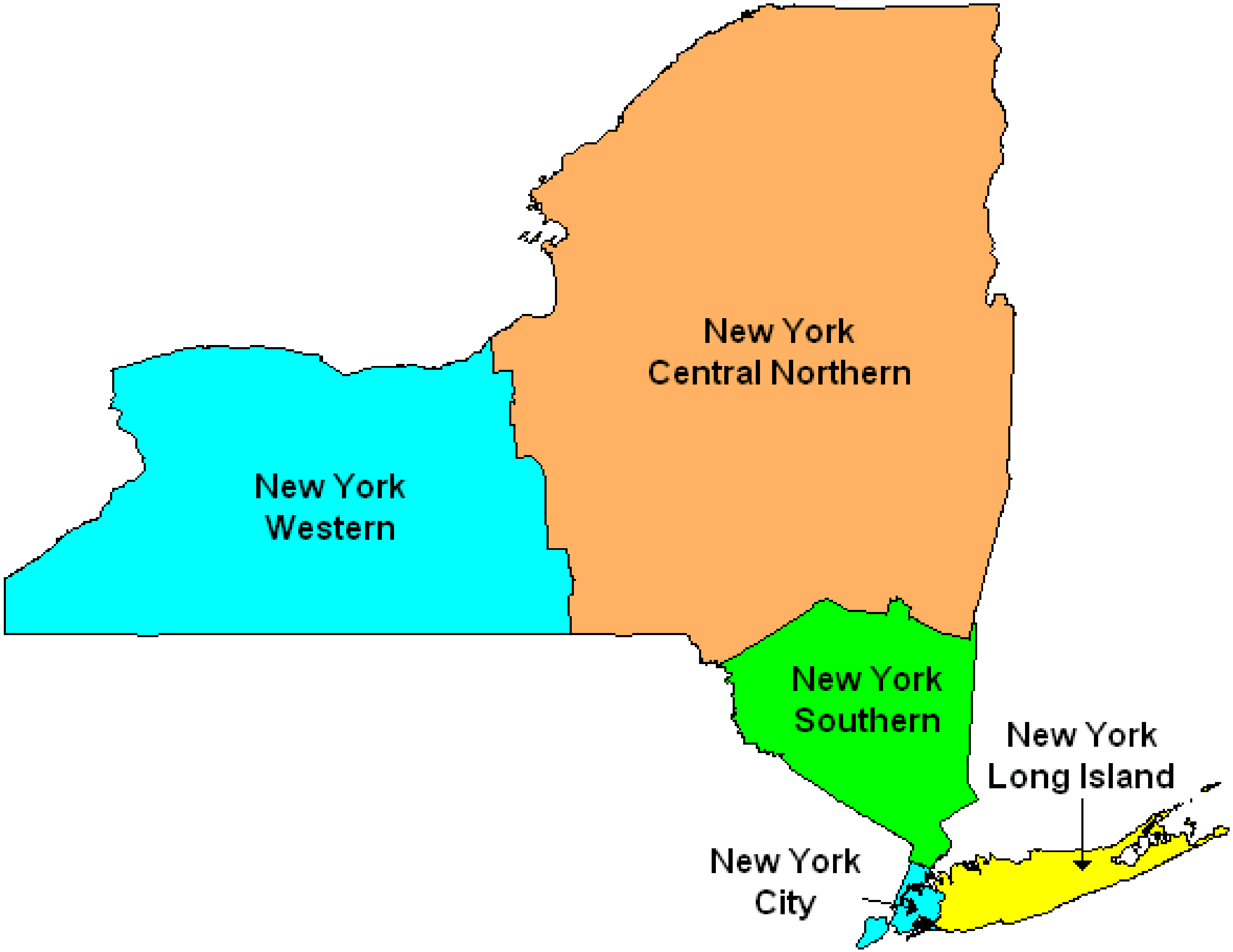
RCI Demand Forecast – Hourly Profile



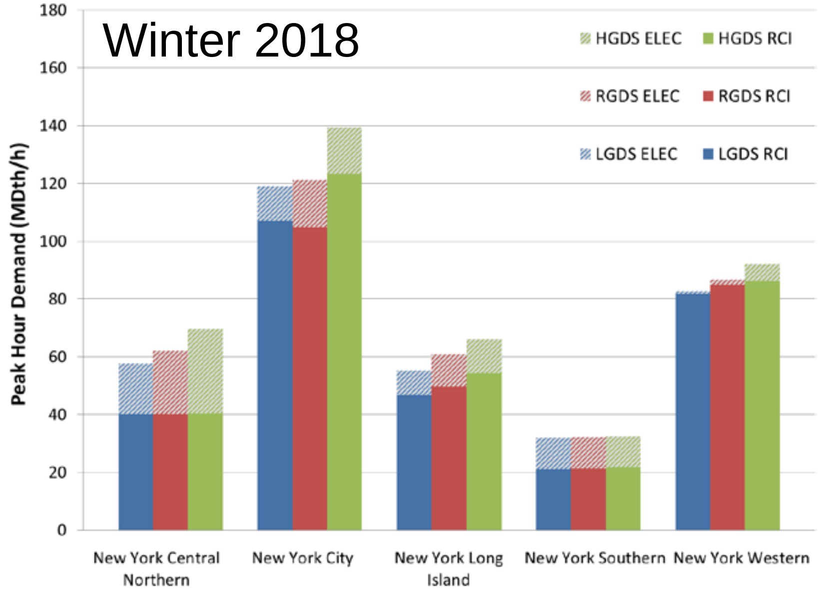
Total Peak Hour Gas Demand

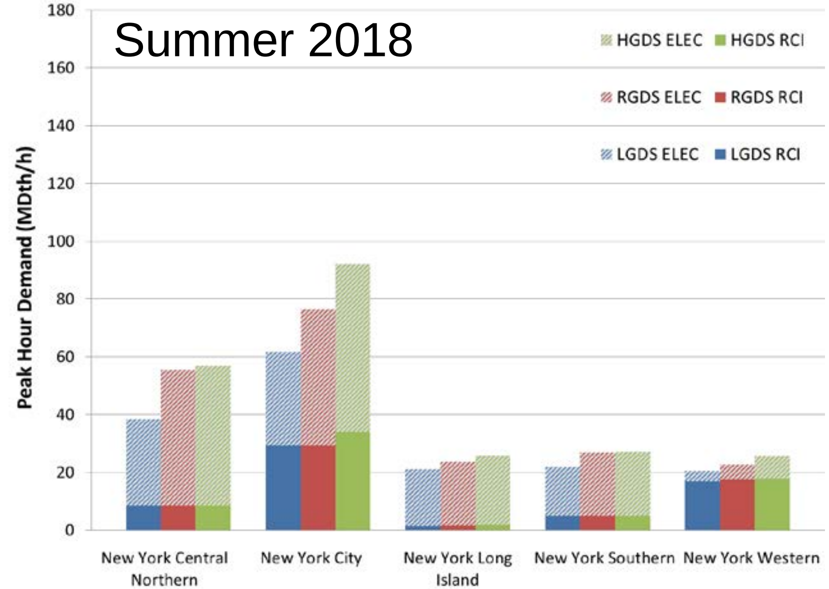


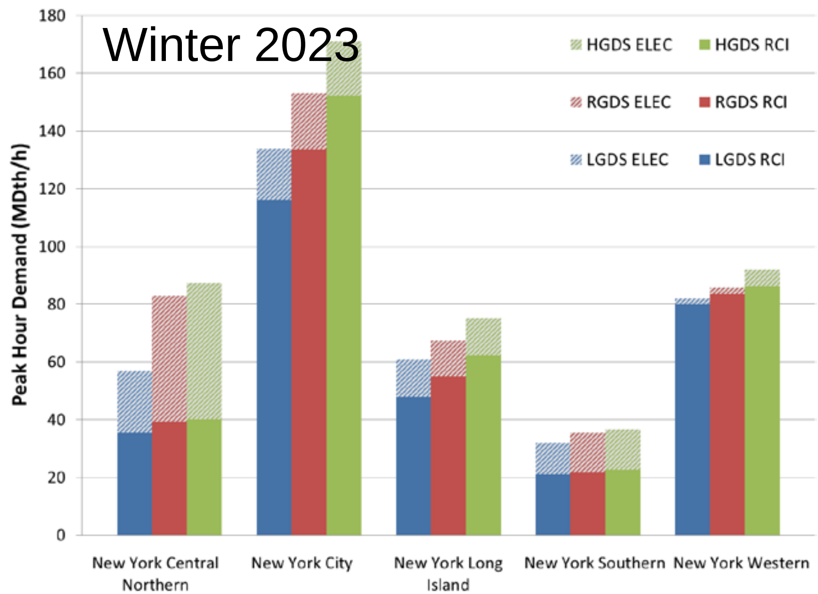
GPCM Locations in NYISO

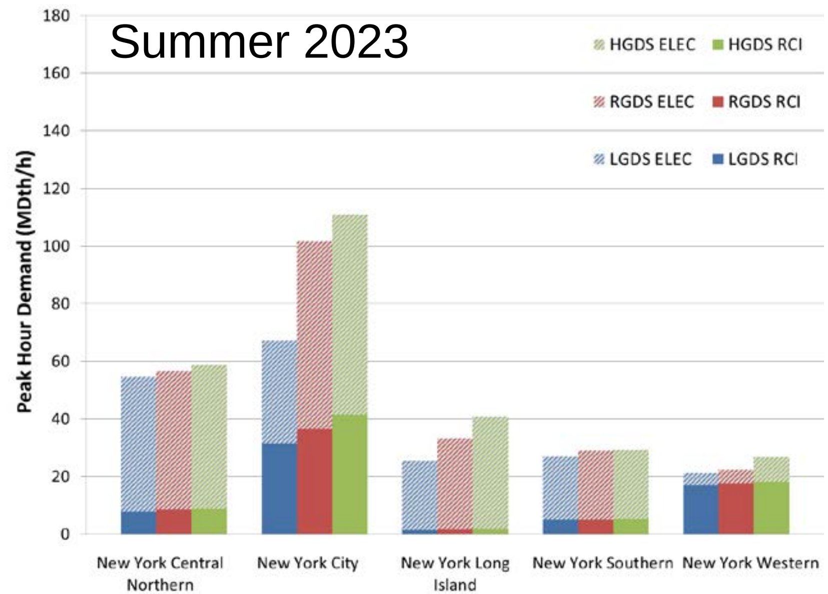


NYISO Peak Hour Demand by Location





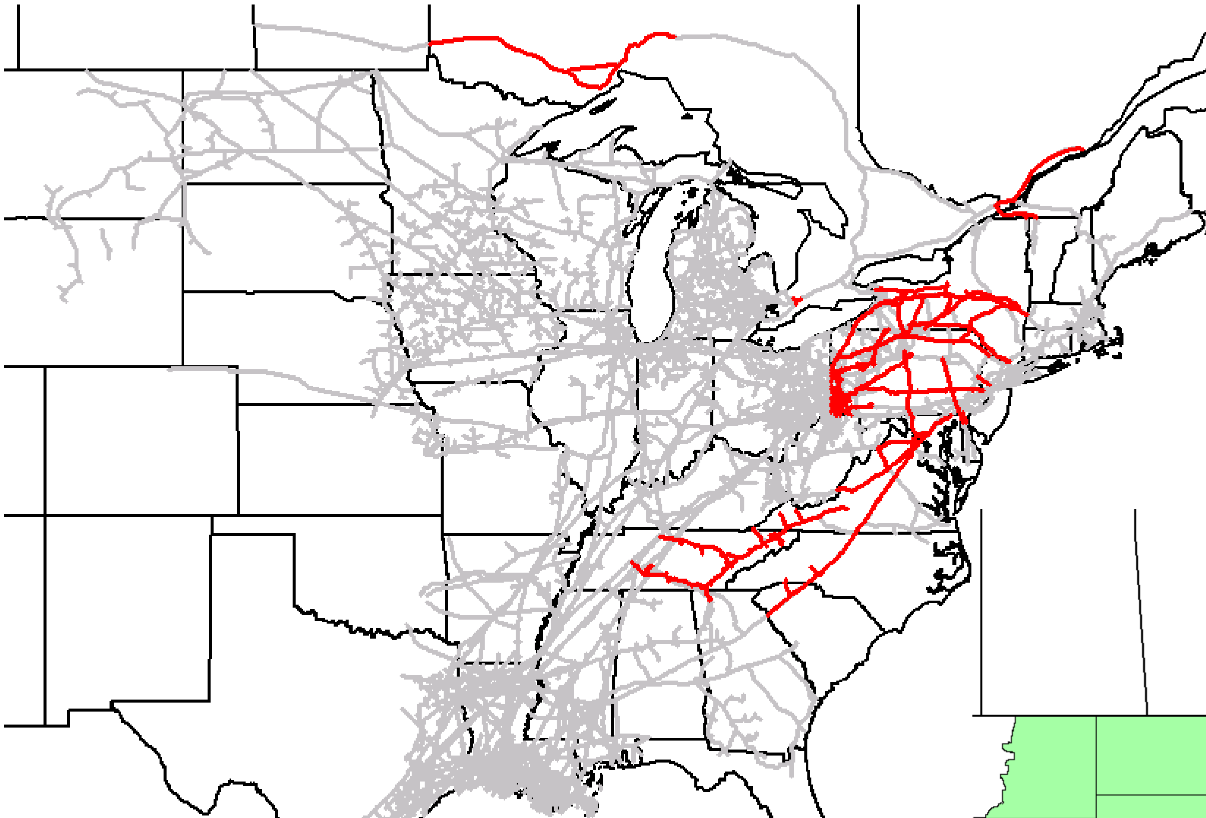




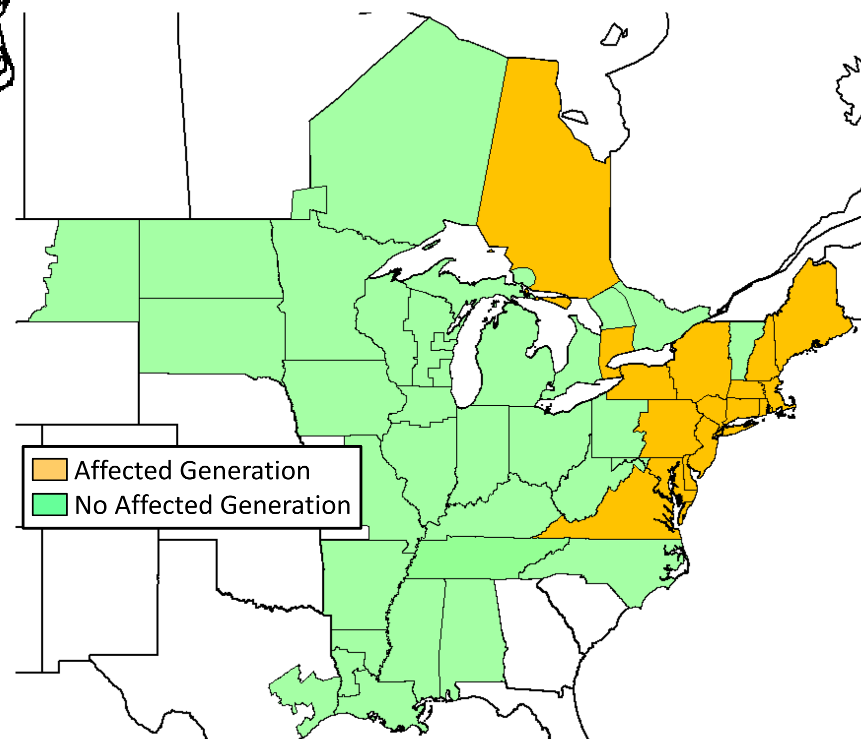
Infrastructure Expansions Relevant to NYISO

- Included in RGDS (agreements known by April 2014)
  - Algonquin: AIM, Atlantic Bridge
  - Constitution
  - Empire/NFG: Tuscarora Lateral, Northern Access 2015
  - Tennessee: Connecticut Expansion, Niagara Expansion
  - Texas Eastern: TEAM 2014
  - Transco: Northeast Connector, Rockaway Lateral
- Included in Sensitivity 13 (announced by April 2014)
  - CNYOG/Stagecoach: Northern Expansion
  - Dominion: New Market
  - Empire/NFG: Central Tioga County, Clermont to Transco, Northern Access 2016
  - Iroquois: South to North
  - Tennessee: Northeast Energy Direct

Constraints: Reference Demand Scenario Winter 2018



"Affected Generation" does not imply a risk to electric reliability



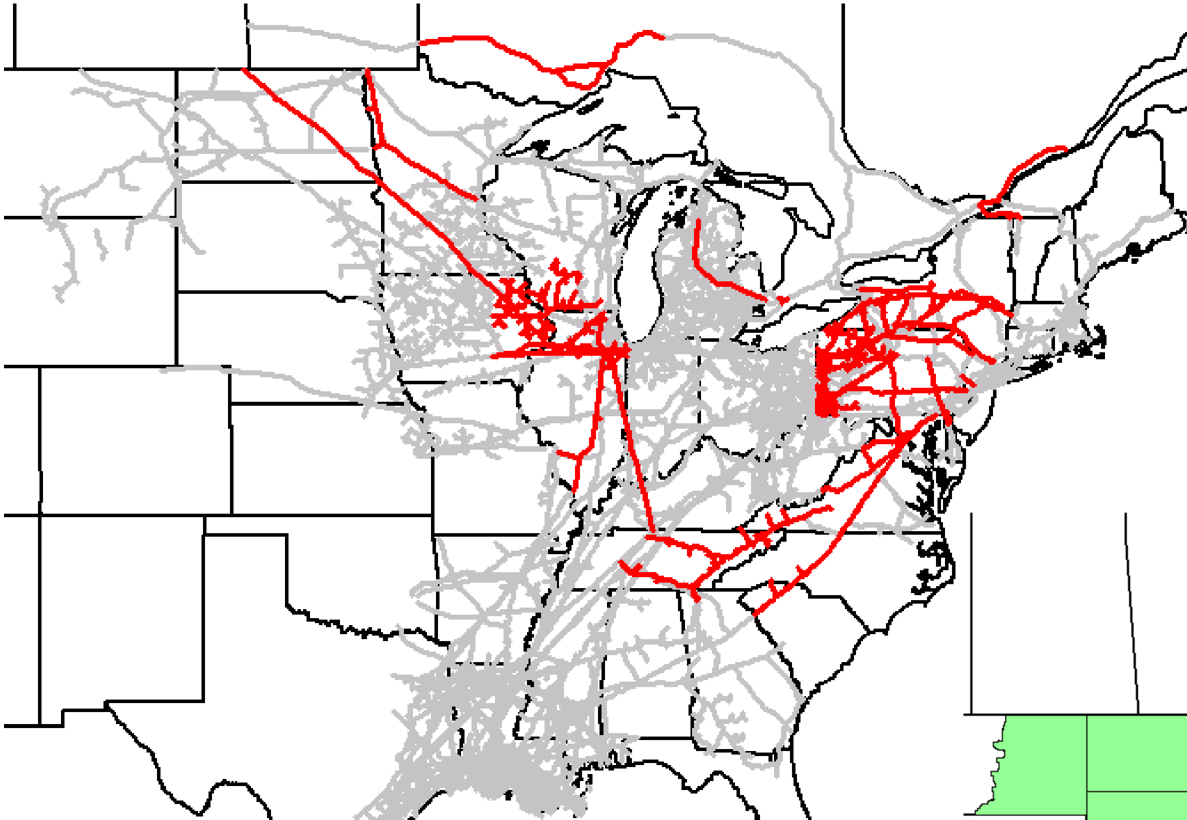
Peak Hour Unserved Generation Gas Demand: 165 MDth (27.6%)

Peak Hour Affected Generation: 21,707 MWh (26.8%)

EIPC Eastern Interconnection Planning Collaborative

LEVITAN & ASSOCIATES, INC.

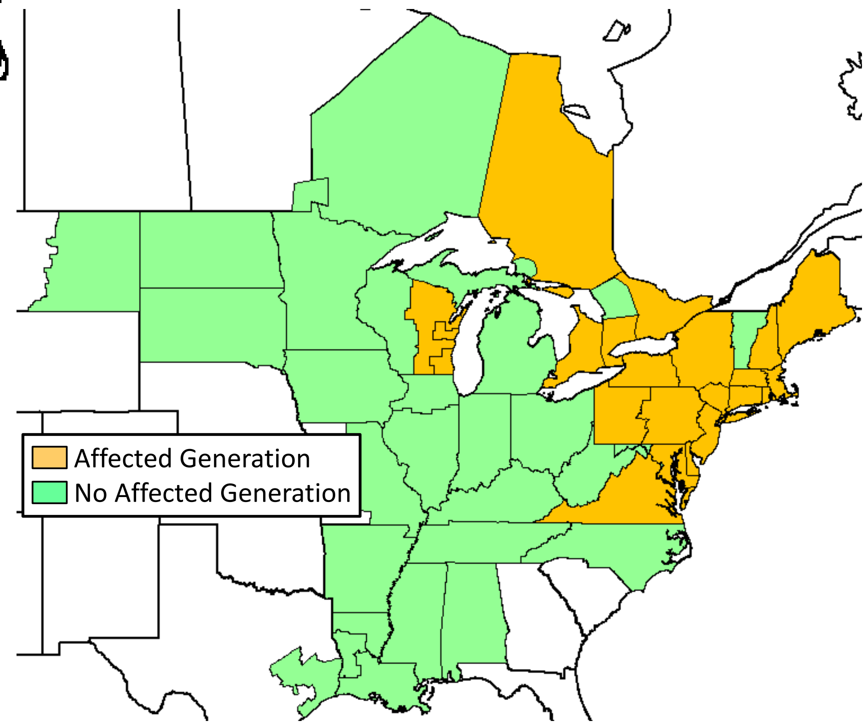
Constraints: High Demand Scenario Winter 2018



"Affected Generation" does not imply a risk to electric reliability

Peak Hour Unserved Generation Gas Demand: 351 MDth (29.4%)

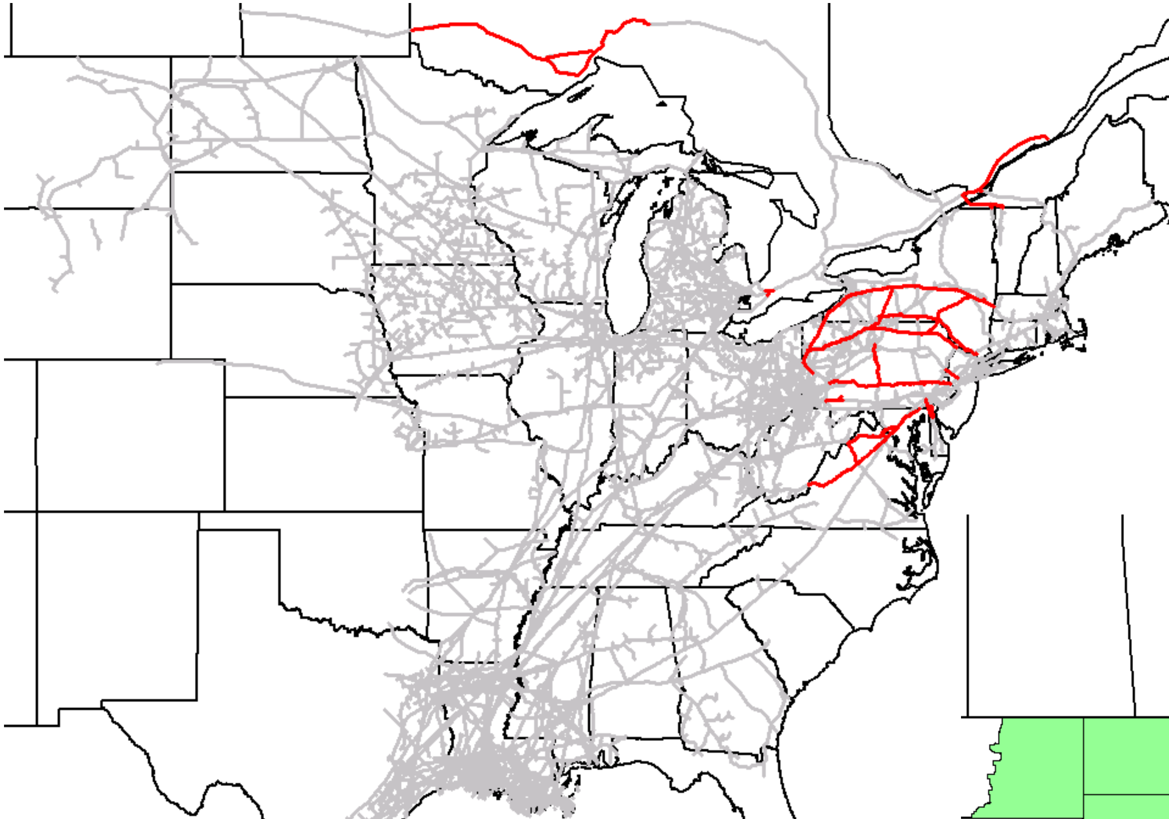
Peak Hour Affected Generation: 45,269 MWh (29.3%)



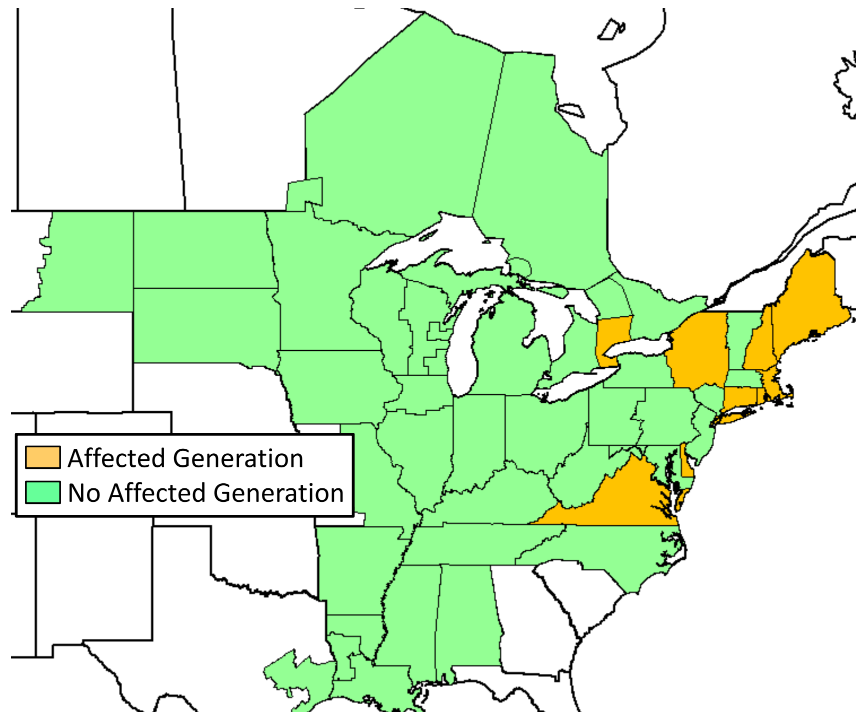
EIPC Eastern Interconnection Planning Collaborative

LEVITAN & ASSOCIATES, INC.

Constraints: Low Demand Scenario Winter 2018



"Affected Generation" does not imply a risk to electric reliability



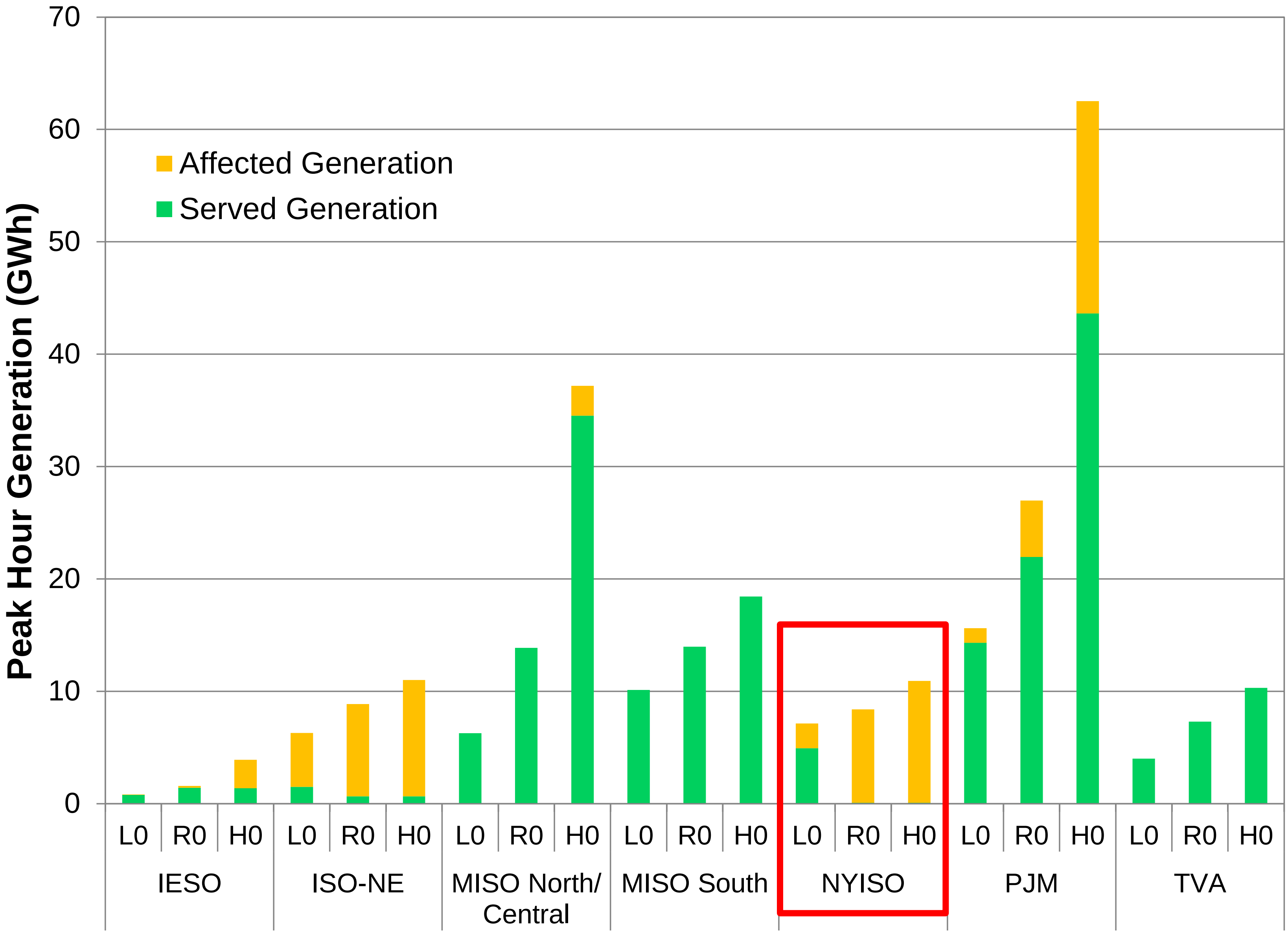
Peak Hour Unserved Generation Gas Demand: 64 MDth (17.6%)

Peak Hour Affected Generation: 8,350 MWh (16.6%)

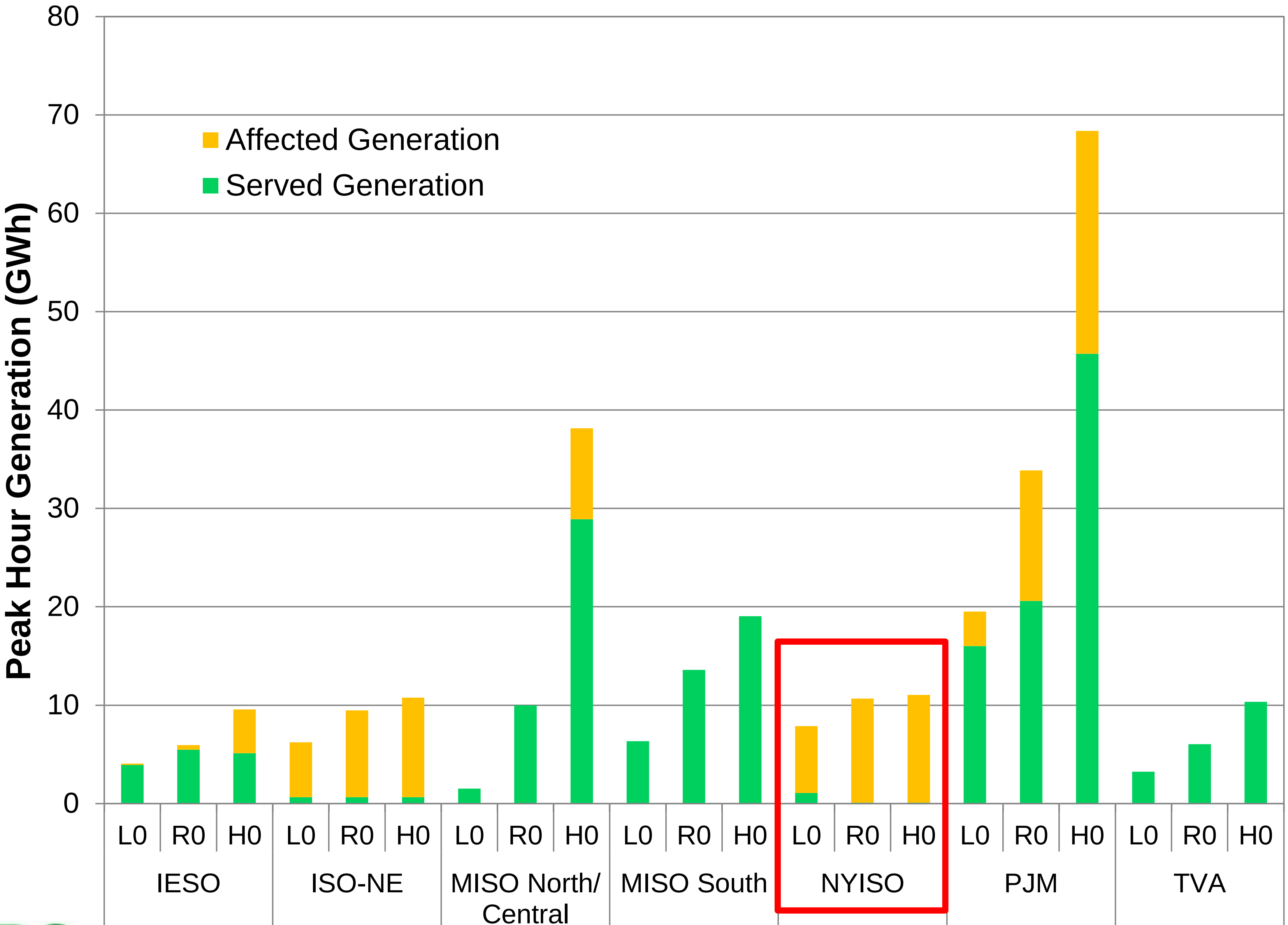
Highlights of NYISO Peak Hour Analysis Results

- Gas infrastructure is constrained in winter 2018 and 2023 under nearly all market conditions and resource mixes
- Despite large P/L buildout into downstate NY, nearly all pipelines have upstream segments that are fully utilized at the winter peak hour
- Constrained Transco segments in PJM also affect downstream generators located on Zones J and K
- Significant dual-fuel capacity mitigates constraints under high daily gas prices (Polar Vortex pricing)
- Expanded pipeline capacity to accommodate Marcellus materially decreases affected generation

Affected Generation in Winter 2018 Peak Hour



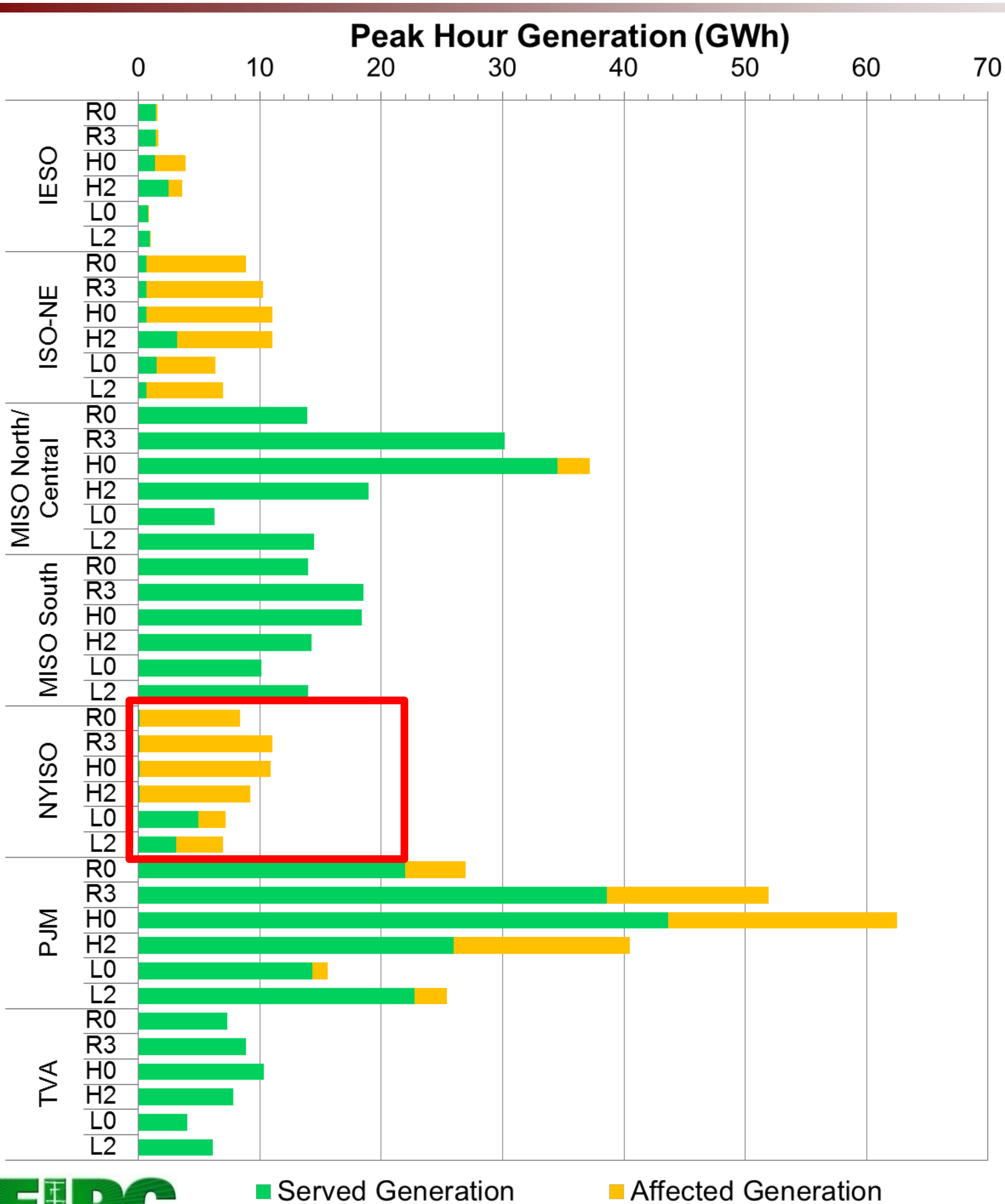
Affected Generation in Winter 2023 Peak Hour



EIPC Eastern Interconnection Planning Collaborative

LEVITAN & ASSOCIATES, INC.

Gas Price Sensitivities - Winter 2018

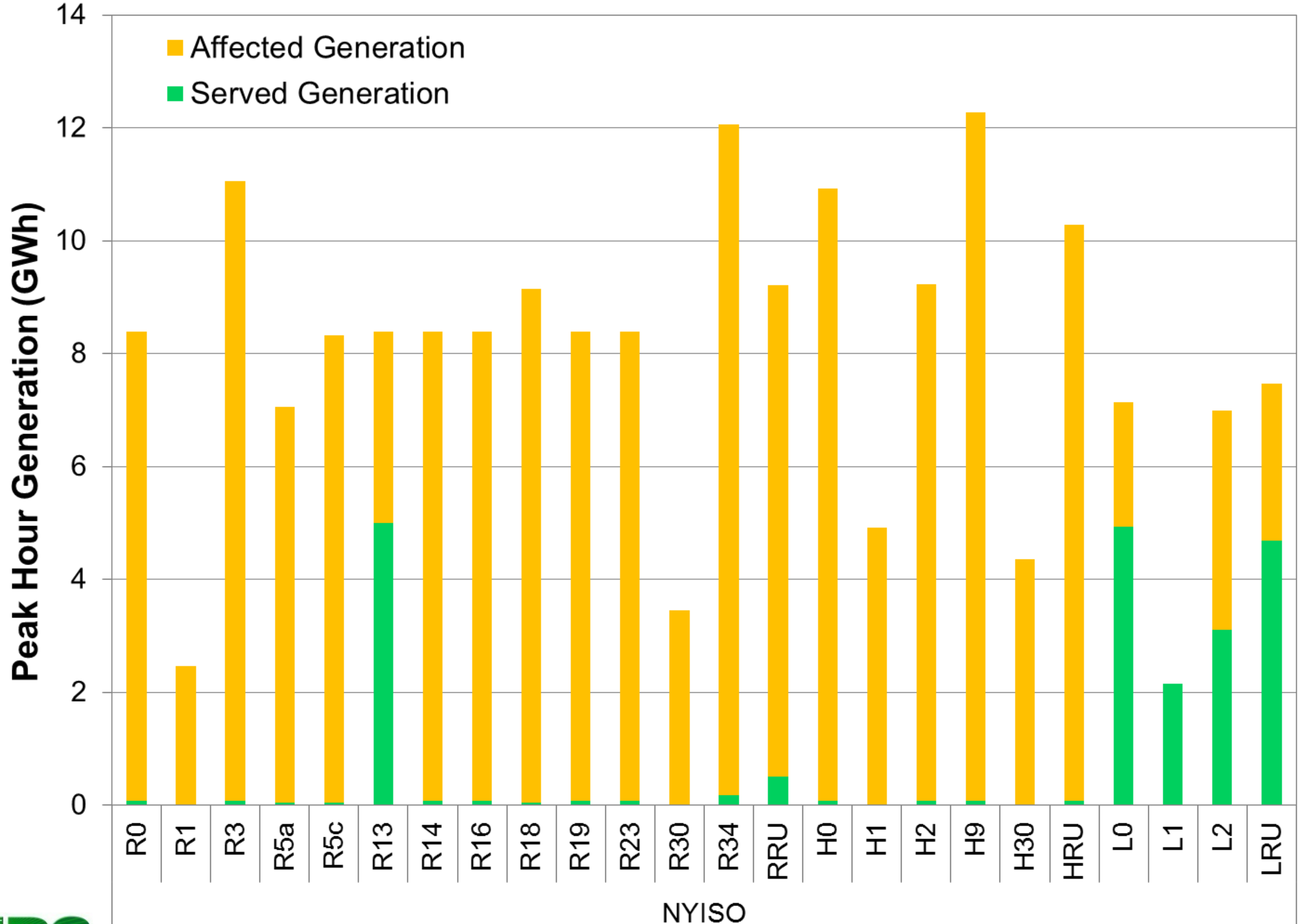


- Lower gas prices (R3) and higher demand (H0) increase affected generation
- Higher gas prices (L3) and lower demand (L0) decrease affected generation
- Dual fuel capacity in SE New York mitigates impact of gas constraints

Sensitivities Tested

Sensitivity	Description
S1 (R/H/L)	Apply market gas prices for peak winter day
S2 (H/L)	Apply RGDS gas prices to HGDS or LGDS
S3 (R)	Significantly lower delivered gas prices
S5a (R)	Deactivation of add'l coal and nuclear, replaced by wind and solar
S5b (R)	Deactivation of additional coal and nuclear, replaced by imports of Quebec hydropower
S5c (R)	Deactivation of additional coal and nuclear, replaced by EE/DR
S9 (H)	Ontario nuclear units scheduled to be refurbished instead reach the end of life after 2018 and before 2023; Indian Point 2 & 3 retire by end of 2015
S13 (R)	Increased infrastructure to enable additional Marcellus/Utica flows to neighboring PPAs
S14 (R)	Increased gas storage availability and deliverability
S16 (R)	Increased sendout from Canaport and Distrigas LNG terminals
S18 (R)	High electric load growth
S19 (R)	High industrial gas demand
S23 (R)	Increased LNG exports from U.S. terminals
S30 (R/H)	Bar gas use in dual fuel resources
S31 (R)	Very cold snap with 90/10 electric and RCI gas demands
S33 (R)	S31 + high forced outage rate for coal and oil units
S34 (R)	Maximum gas demand on electric sector
S36 (R)	S33 + Selected nuclear units unavailable
S37 (R)	S13 + Canaport converted to LNG export facility

All NYISO Sensitivities – Winter 2018



Frequency / Duration Analysis

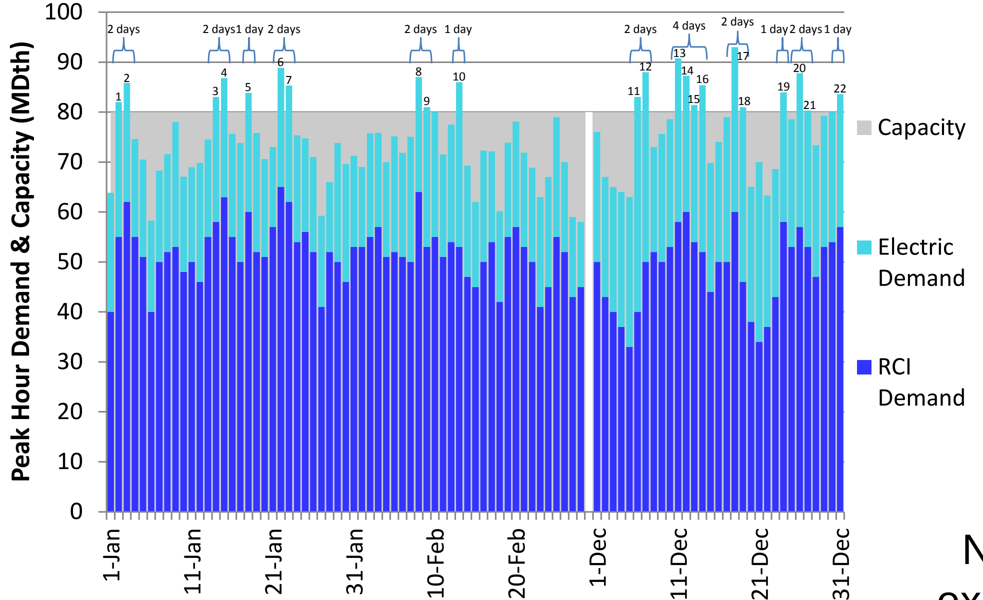
- F-D of seasonal constraints based on expected demand duration curves
  - Demand duration curves based on peak hour electric model results and historical RCI demand data
  - Duration curves for all demand provided through a constrained segment were combined to determine total daily peak hour demand
  - Daily peak hour conditions were analyzed for three winter and three summer months
  - Interconnection flows accounted for
- Forecast of RCI and electric gas demand is compared to the maximum flow capability of the segment to determine number and pattern of high congestion days
- Unserved demand allocated to genco loads

RGDS S0 Winter 2018: Frequency & Duration

Constraint	# of Events	Min. Duration (Days)	Max. Duration (Days)	Total # of Days
Columbia Gas VA/MD	12	1	5	23
Columbia Gas W PA/NY	11	1	5	21
Constitution	5	1	12	25
Dominion Eastern NY	6	1	6	15
Dominion Western NY	1	4	4	4
Dominion Southeast	7	1	12	22
East Tennessee Mainline	7	1	2	9
Eastern Shore	11	1	10	51
Empire Mainline	5	1	12	21
Millennium	4	1	59	83
NB/NS Supply	13	1	20	58
Tennessee Z4 PA	10	1	7	30
Tennessee Z5 NY	2	31	59	90
Texas Eastern M2 PA South	10	1	15	50
Texas Eastern M3 North	10	2	7	39
TransCanada Ontario West	5	1	5	12
TransCanada Quebec	9	1	14	30
Transco Leidy Atlantic	8	2	23	59
Transco Z5	3	1	7	9
Transco Z6 Leidy to 210	5	1	3	8
Union Gas Dawn	2	1	3	4

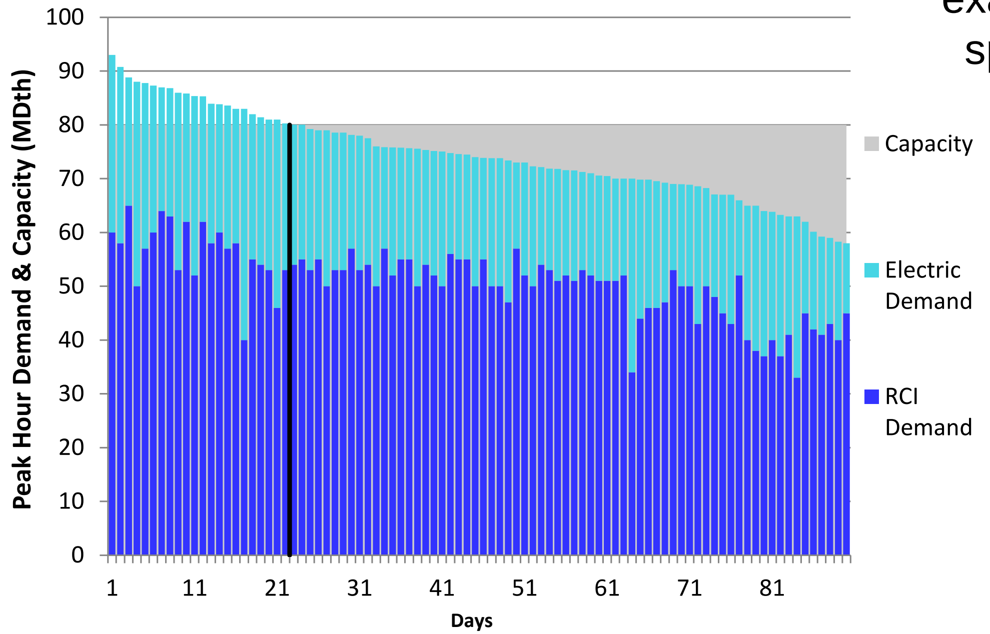
Frequency-Duration Results Format

Chronological Demand

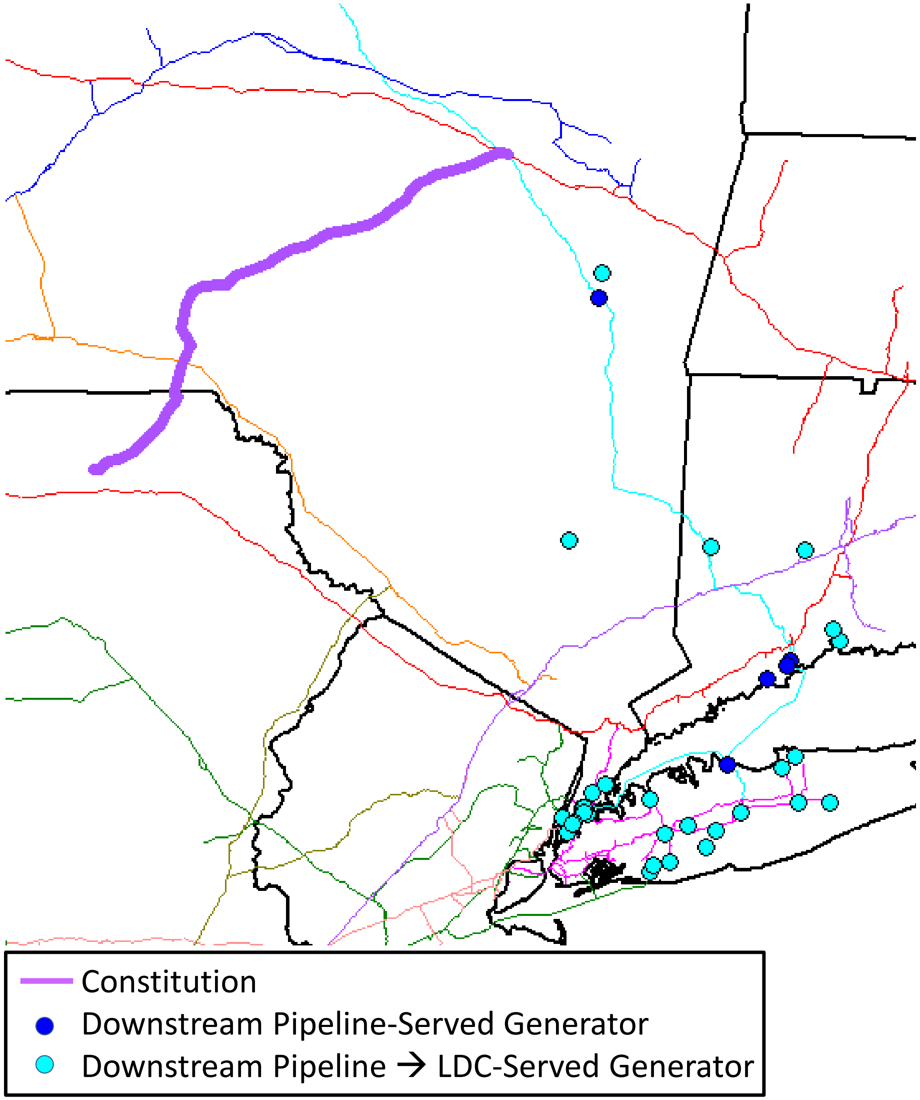


Note: Charts are examples, not for a specific segment

Descending Demand

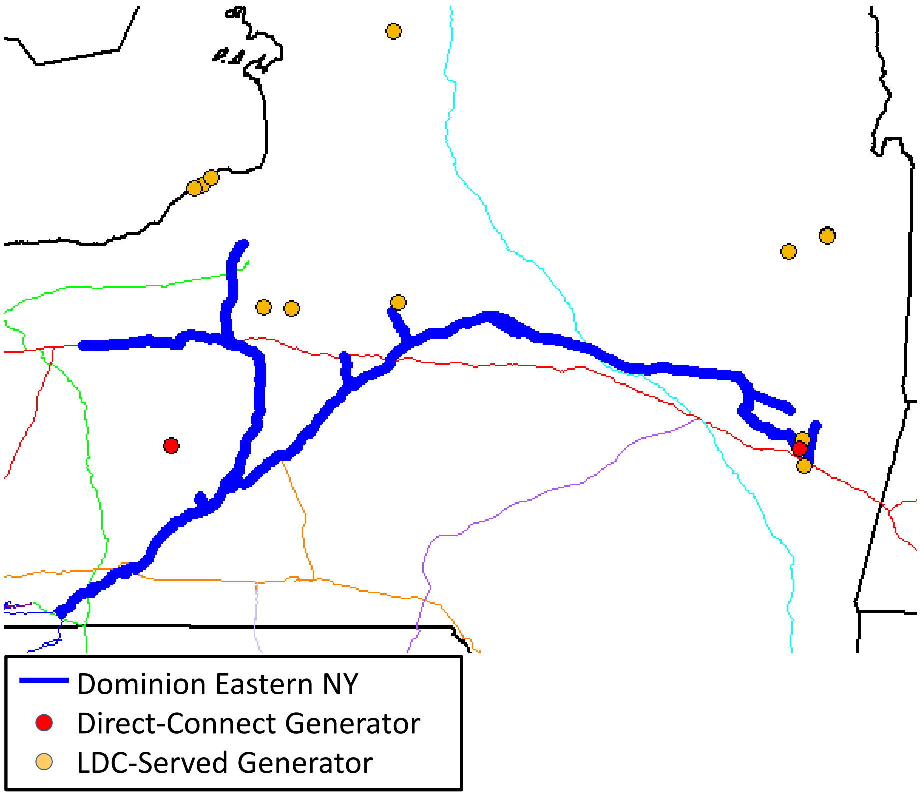


Winter 2018: Constitution



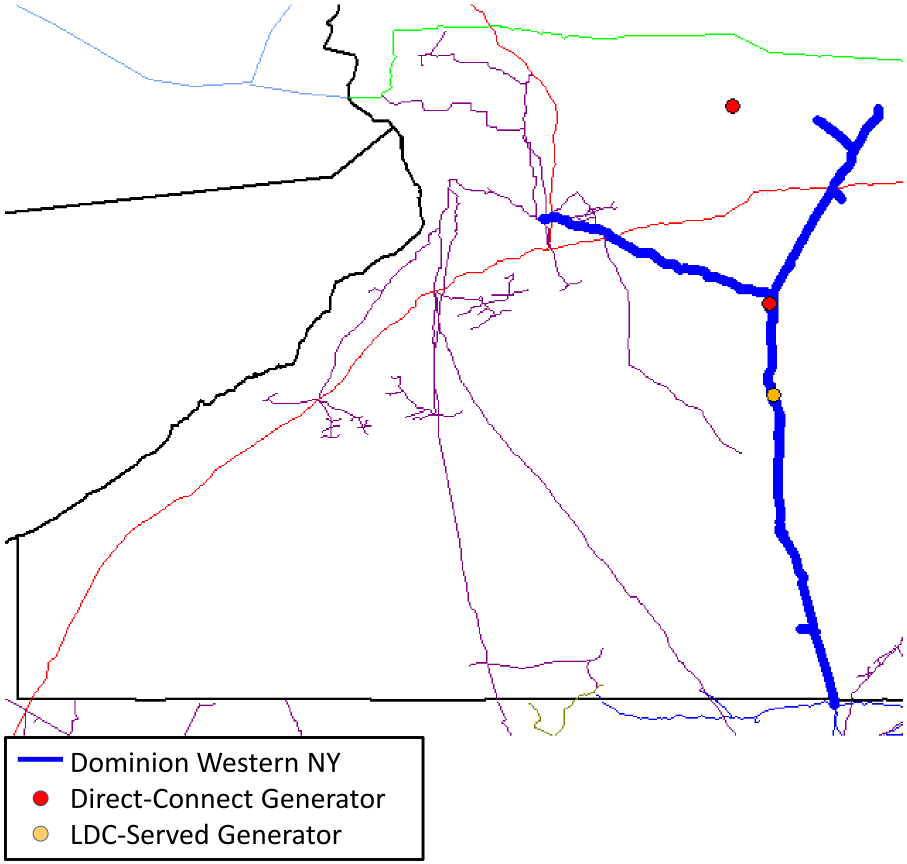
# of Events	Min. Duration (Days)	Max. Duration (Days)	Total # of Days
5	1	12	25

Winter 2018: Dominion Eastern NY



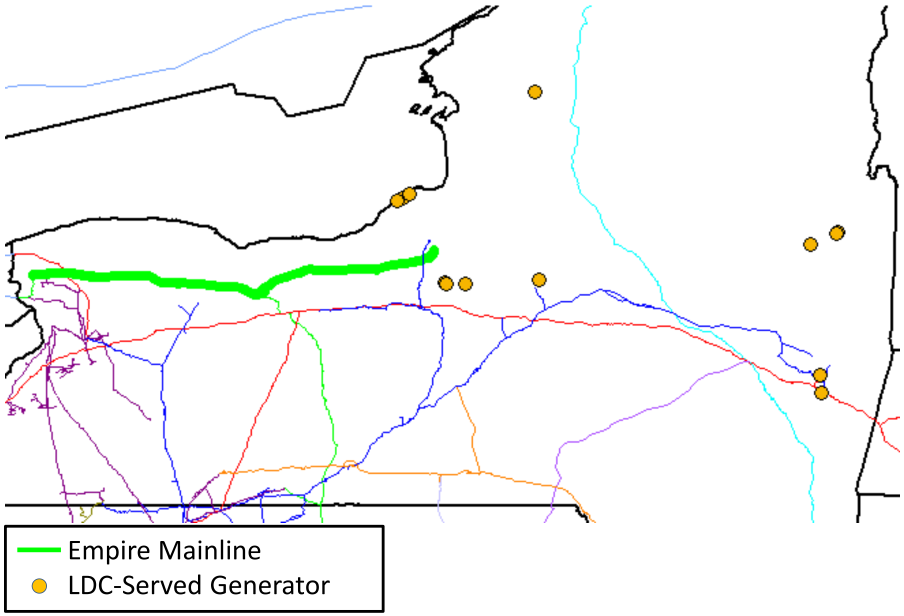
# of Events	Min. Duration (Days)	Max. Duration (Days)	Total # of Days
6	1	6	15

Winter 2018: Dominion Western NY



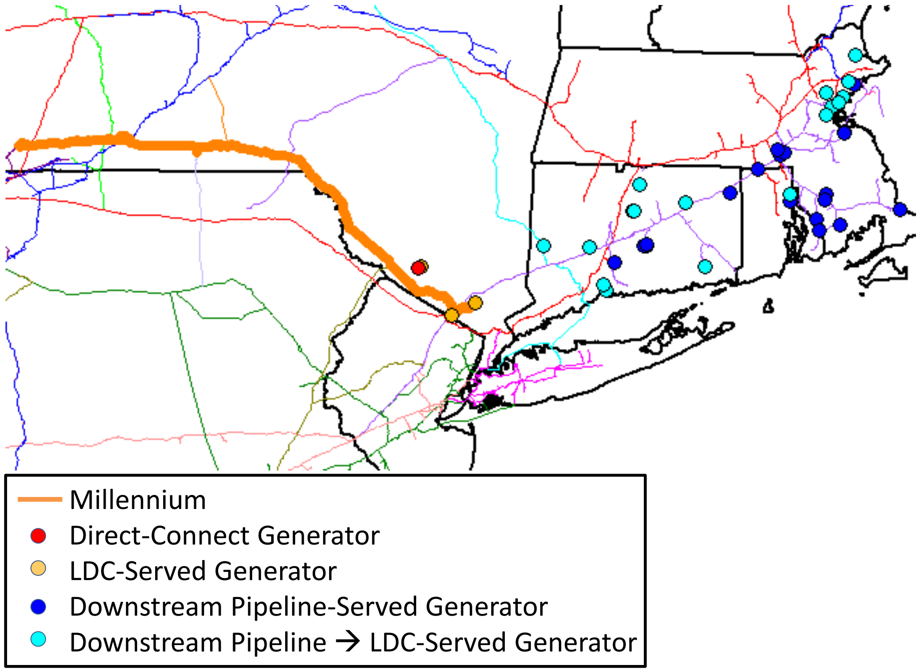
# of Events	Min. Duration (Days)	Max. Duration (Days)	Total # of Days
1	4	4	4

Winter 2018: Empire Mainline



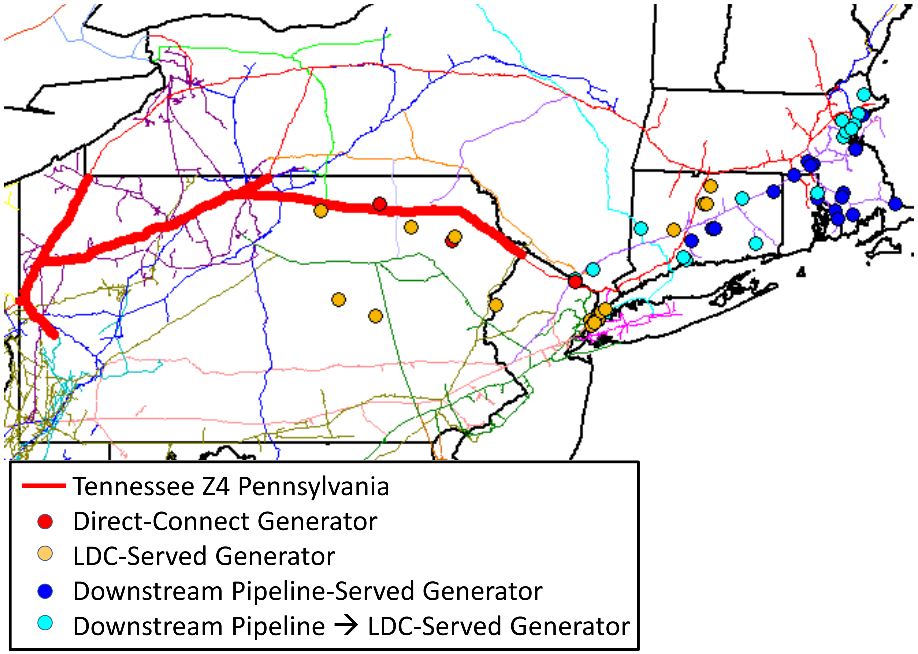
# of Events	Min. Duration (Days)	Max. Duration (Days)	Total # of Days
5	1	12	21

Winter 2018: Millennium



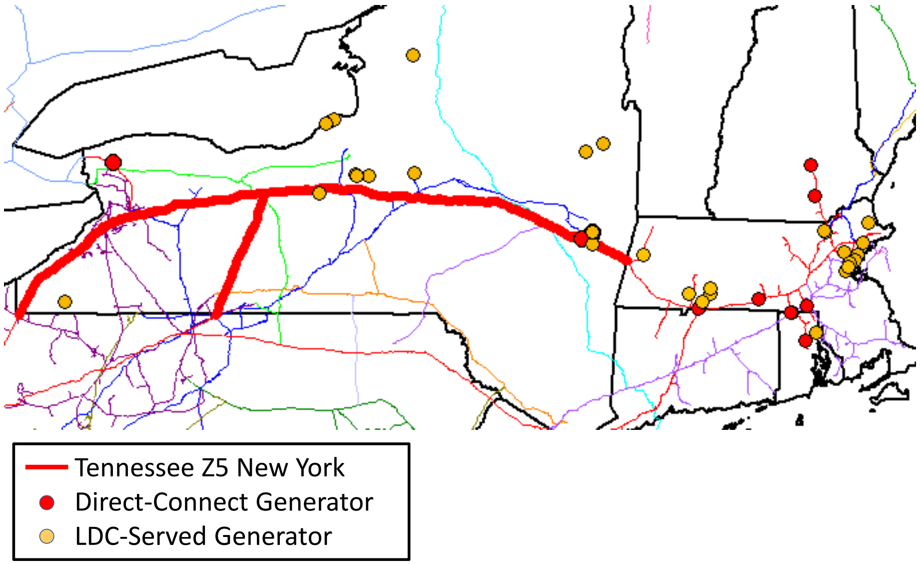
# of Events	Min. Duration (Days)	Max. Duration (Days)	Total # of Days
4	1	59	83

Winter 2018: Tennessee Z4



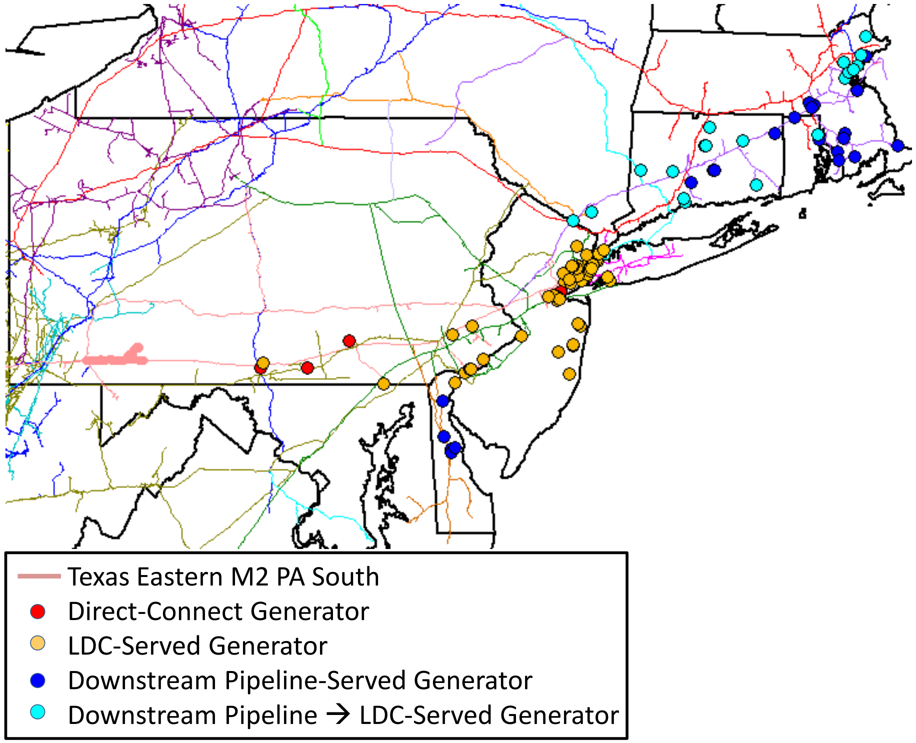
# of Events	Min. Duration (Days)	Max. Duration (Days)	Total # of Days
10	1	7	30

Winter 2018: Tennessee Z5 NY



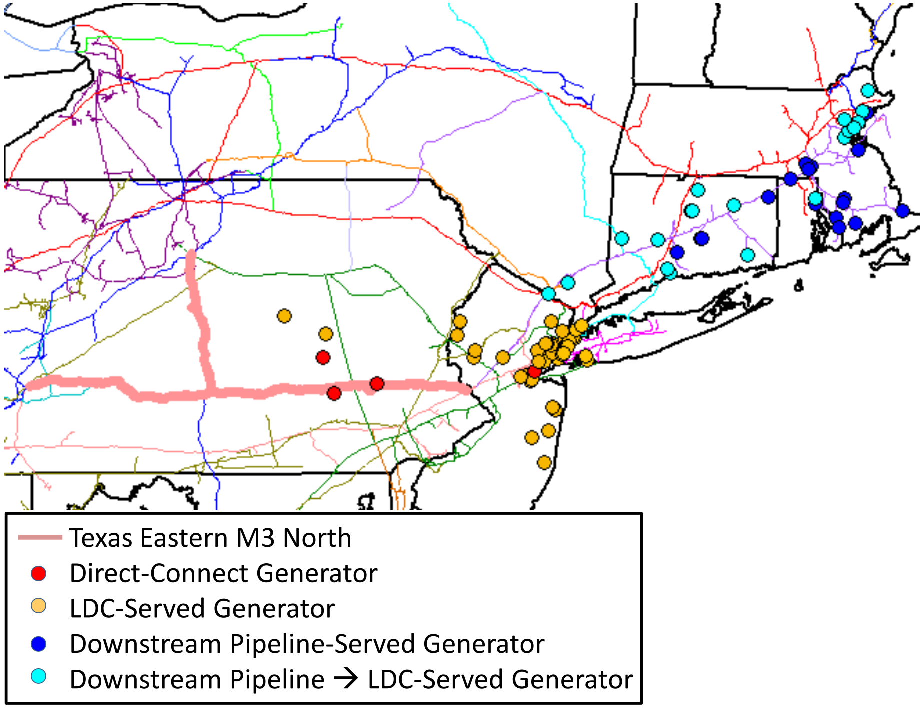
# of Events	Min. Duration (Days)	Max. Duration (Days)	Total # of Days
2	31	59	90

Winter 2018: Texas Eastern M2 PA



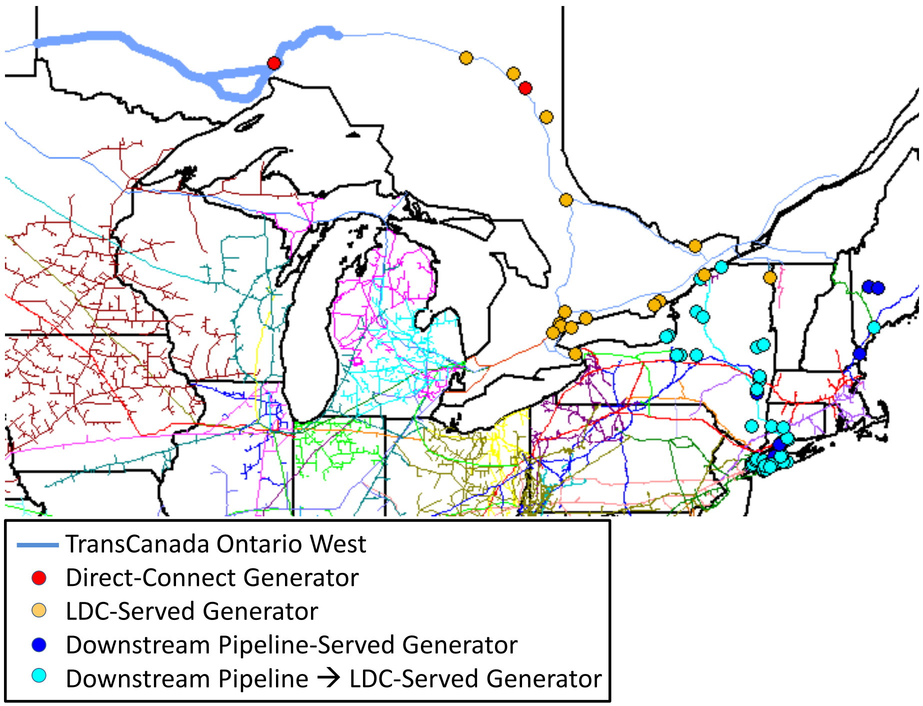
# of Events	Min. Duration (Days)	Max. Duration (Days)	Total # of Days
10	1	15	50

Winter 2018: Texas Eastern M3 North



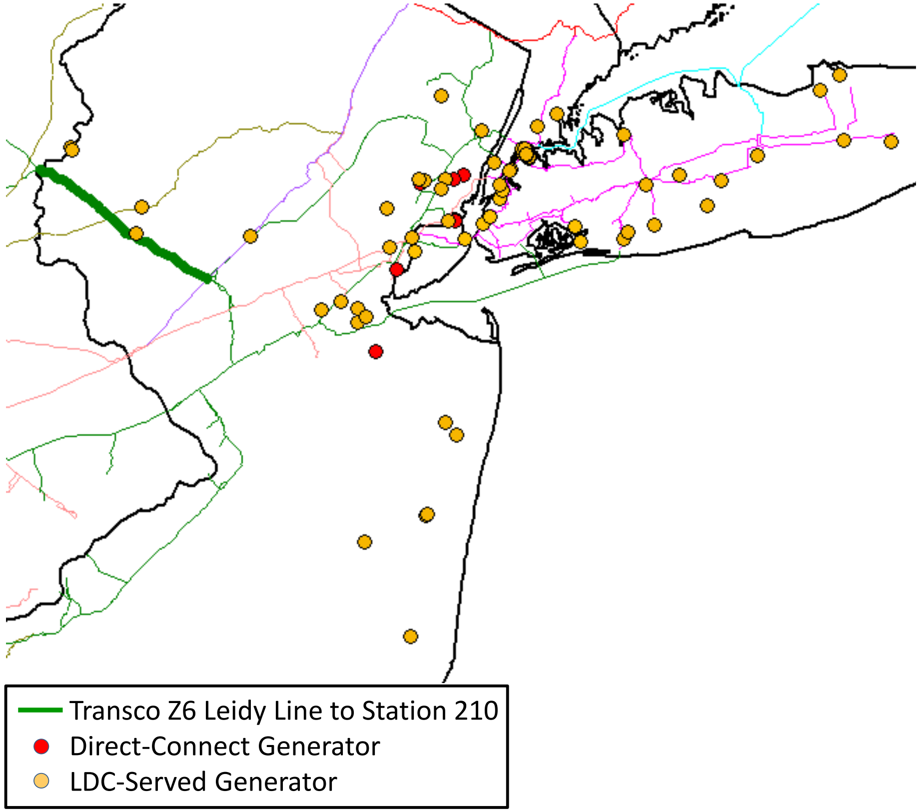
# of Events	Min. Duration (Days)	Max. Duration (Days)	Total # of Days
10	2	7	39

Winter 2018: TransCanada Ontario West



# of Events	Min. Duration (Days)	Max. Duration (Days)	Total # of Days
5	1	5	12

Winter 2018: Transco Leidy Line to Station 210



# of Events	Min. Duration (Days)	Max. Duration (Days)	Total # of Days
5	1	3	8

Risk Factors and Market Dynamics

Market Dynamic and/or Risk Factor	NYISO	IESO	ISO-NE	MISO North/ Central	MISO South	PJM	TVA
Transport Deficits	Red	Green	Red	Green	Green	Red	Green
New Pipeline Additions	Yellow	Yellow	Red	Green	Yellow	Green	Green
Proximity to Shale Gas	Yellow	Yellow	Red	Green	Yellow	Green	Yellow
Reversal-of-Flow	Green	Green	Red	Green	Yellow	Green	Green
Available Coal Output	Yellow	Green	Yellow	Red	Yellow	Red	Yellow
Nuclear Retirements/Delays	Yellow	Red	Green	Green	Green	Yellow	Green
LNG Import Constraints	Green	Green	Red	Green	Green	Yellow	Green
LNG Export Constraints	Green	Green	Green	Green	Yellow	Yellow	Green
Transmission Transfer Limits (Electric)	Green	Green	Green	Green	Yellow	Yellow	Green
Generator FT Entitlements	Yellow	Green	Yellow	Yellow	Yellow	Yellow	Green
Generator Reliance on Non-Firm Arrangements	Red	Green	Red	Green	Green	Red	Green
Dual Fuel Capability	Green	Yellow	Green	Yellow	Yellow	Yellow	Green
Renewables Penetration	Yellow	Green	Yellow	Yellow	Green	Yellow	Green

Legend	Negligible or no impact on affected generation (Green)	Low to moderate impact on affected generation (Yellow)	High impact on affected generation (Red)

Risk Factors and Market Dynamics

Market Dynamic and/or Risk Factor	NYISO	IESO	ISO-NE	MISO North/ Central	MISO South	PJM	TVA
Transport Deficits							

- Deficits in Capital District, LHV, downstate NY recur throughout peak heating season in response to RCI demand

Market Dynamic and/or Risk Factor	NYISO	IESO	ISO-NE	MISO North/ Central	MISO South	PJM	TVA
Generator Reliance on Non-Firm Arrangements							

- NYISO generators largely rely on non-firm transportation arrangements, particularly on the NYFS

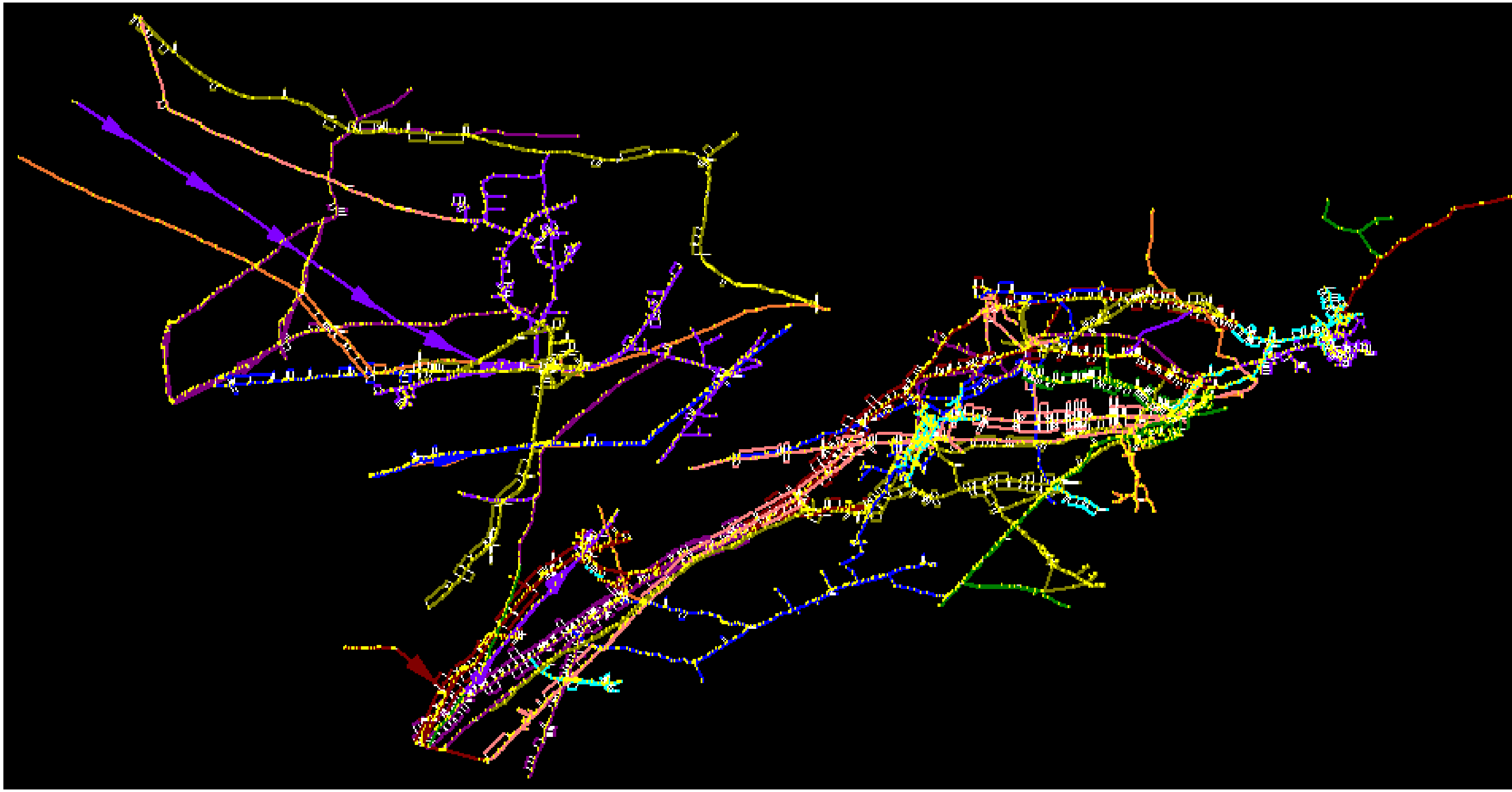
Target 3

Natural Gas and Electric System Contingency Analysis

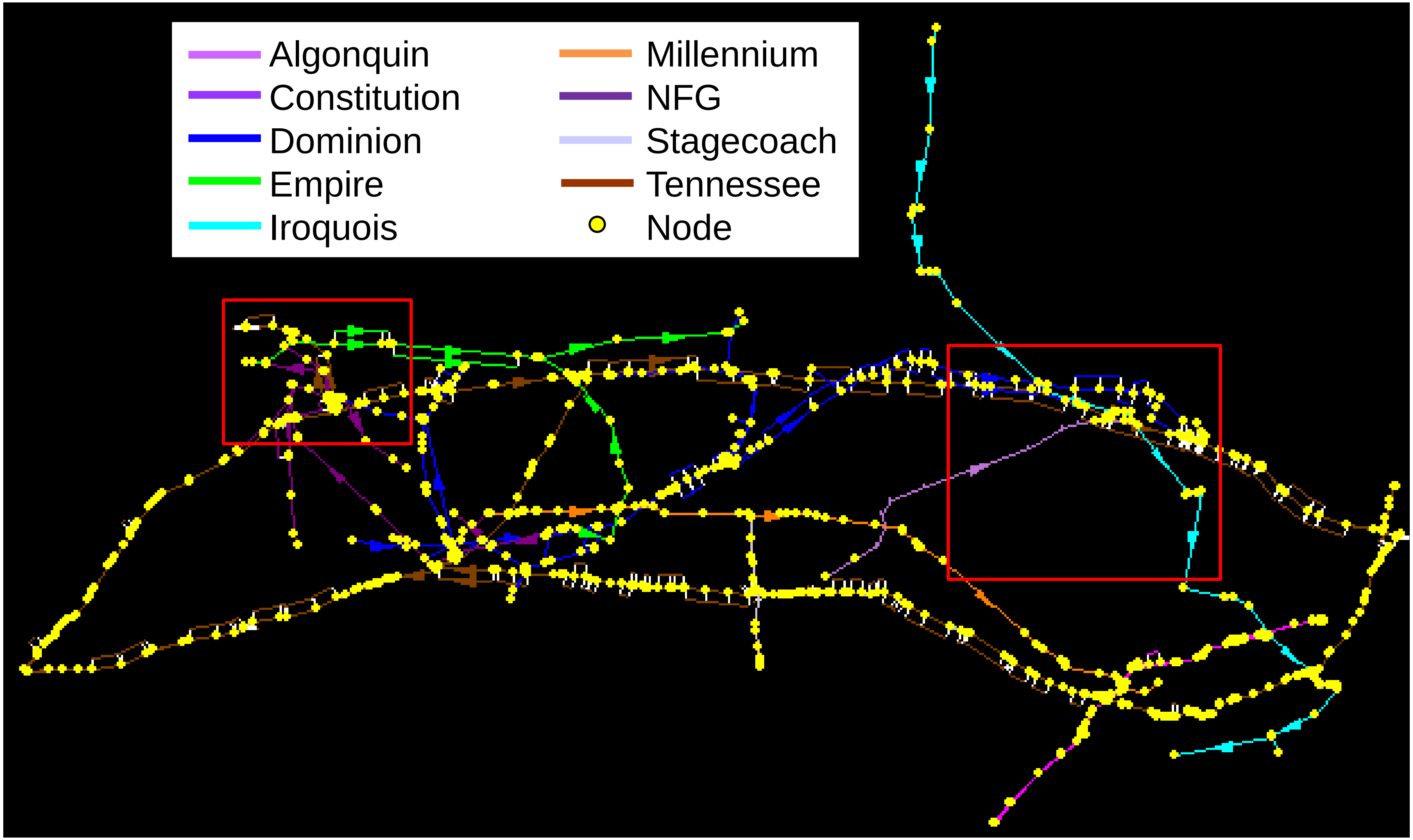
Contingency Analysis Approach

- Emphasis is placed on the physical capability of the consolidated network of pipeline and storage infrastructure to maintain service to RCI and generation customers post-contingency
  - Pipeline contractual obligations are not modeled, *i.e.*, on par post-event
  - Generator and RCI demands not differentiated, revealing the outer bound re the post-contingency sustainability of service
- Identify plants that trip off line due to delivery pressures below 485 psig, and the time interval between the contingency event and the pressure trigger
- Affected generation following a contingency is **NOT** tantamount to unserved electric energy (mitigation measures are available)
- MISO South not hydraulically modeled due to its robust available capacity
- LDC assessments either included in hydraulic models or evaluated by LDC separately

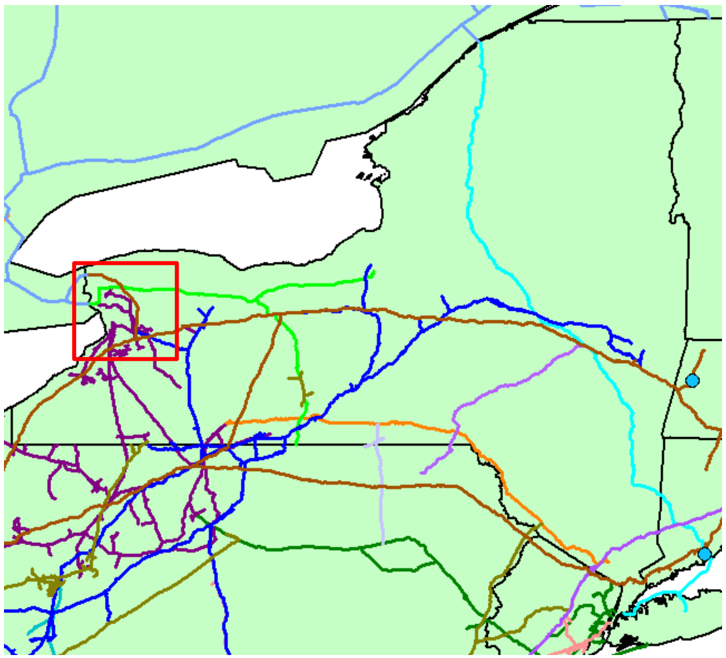
Hydraulic Model Study Region Footprint

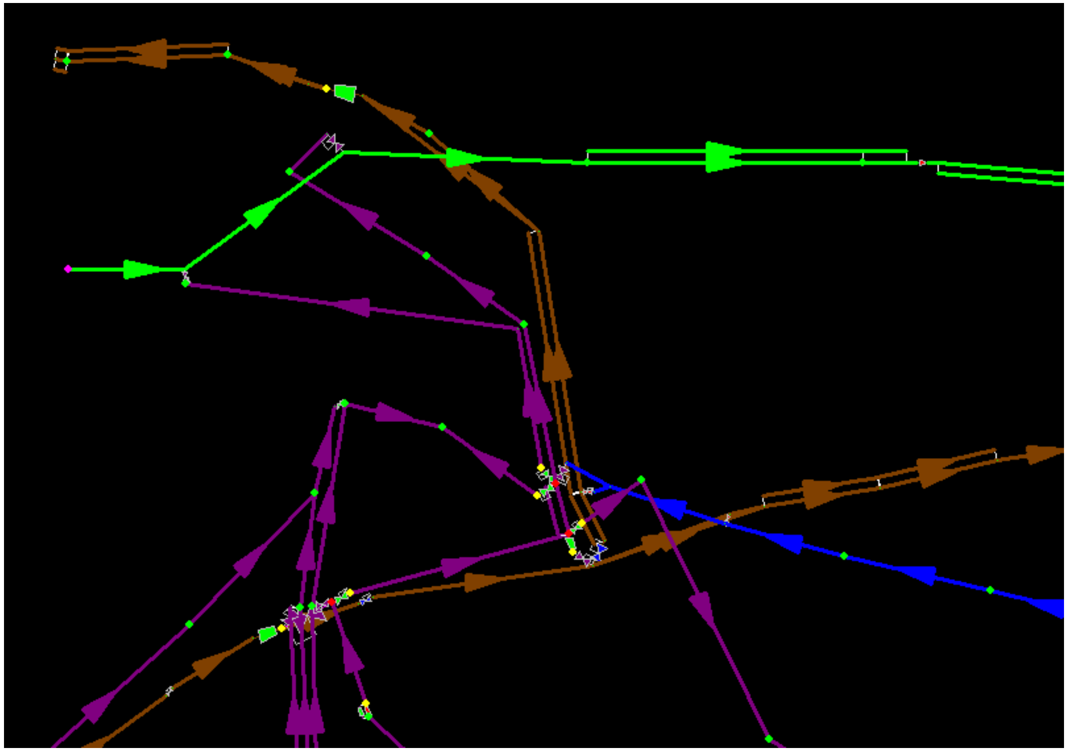


NYISO Hydraulic Model



NYISO Hydraulic Model – Niagara Area

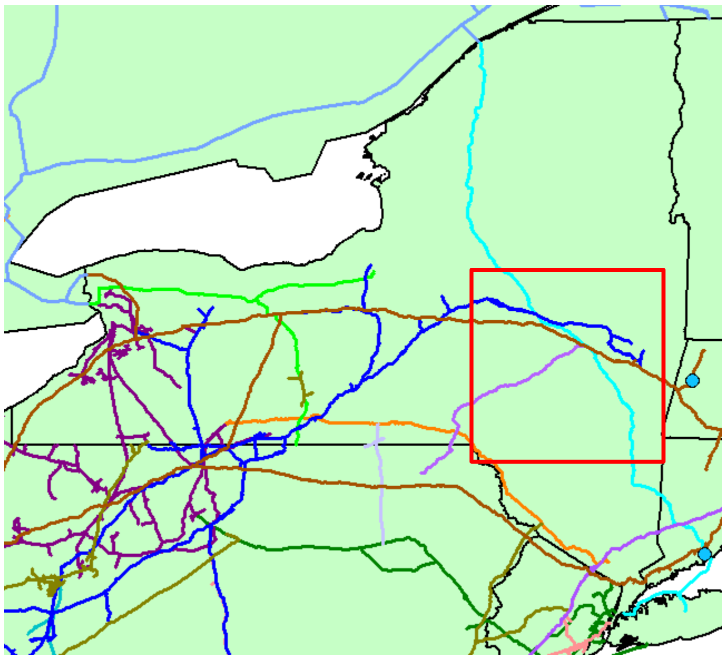


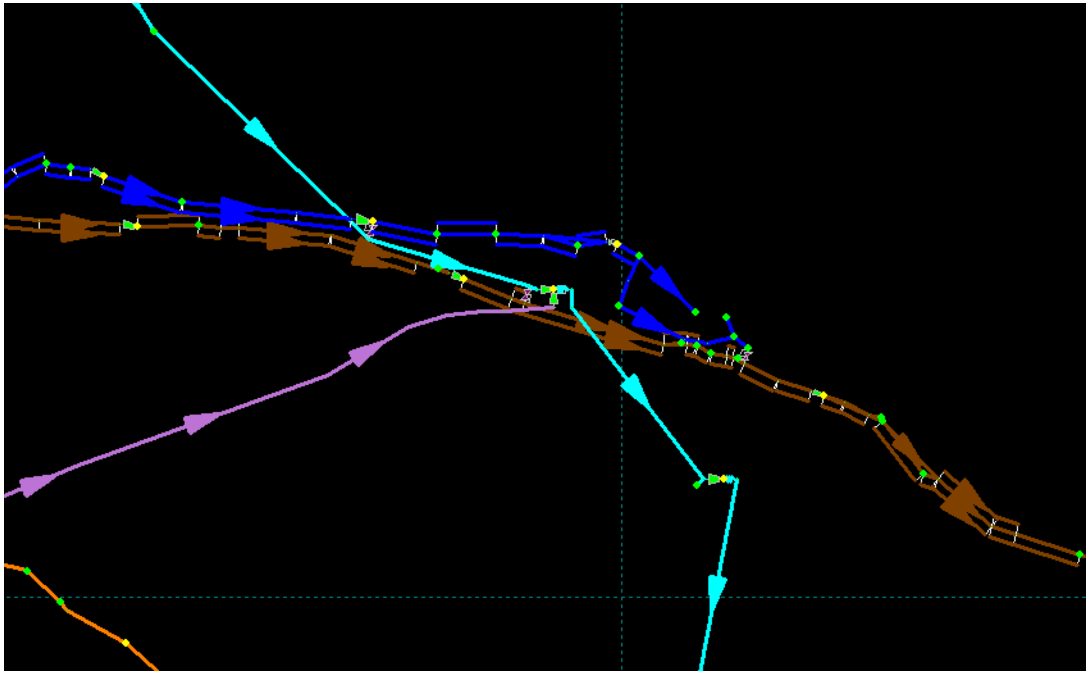


EIPC
Eastern Interconnection Planning Collaborative

LEVITAN & ASSOCIATES, INC.

NYISO Hydraulic Model – Wright Area





EIPC
Eastern Interconnection Planning Collaborative

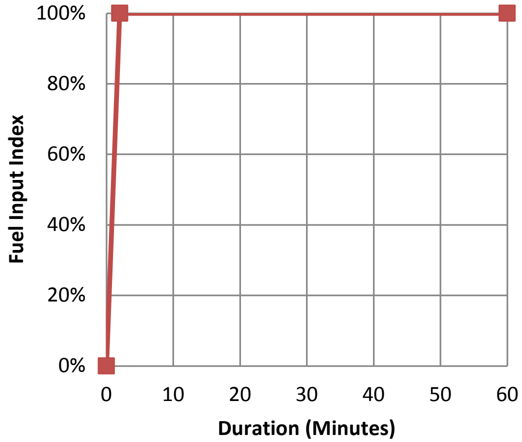
LEVITAN & ASSOCIATES, INC.

Target 3 Gas Demand Profile Inputs

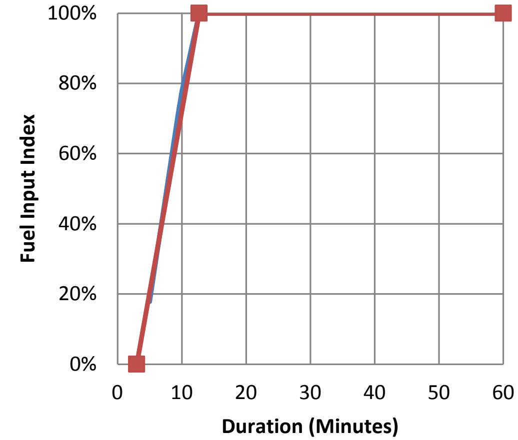
- Pre- and post-contingency hourly gas use profiles derived from AURORAxmp chronological production cost model based on reference and high gas demand scenarios
- Sub-hourly ramping profiles developed for each gas-fired technology type
- Intraday RCI demand profile developed in Target 2 applied to all RCI loads across the Study Region

Sub-Hourly Ramping Profiles by Technology Type

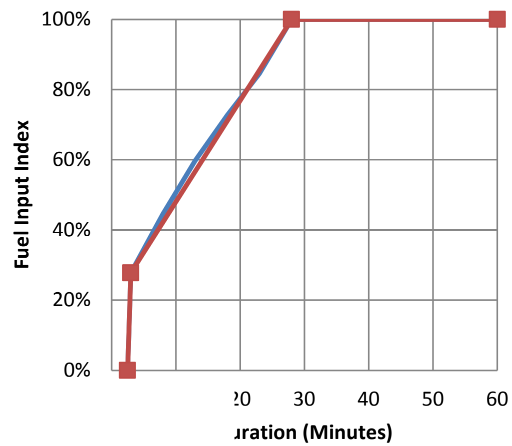
Internal Combustion



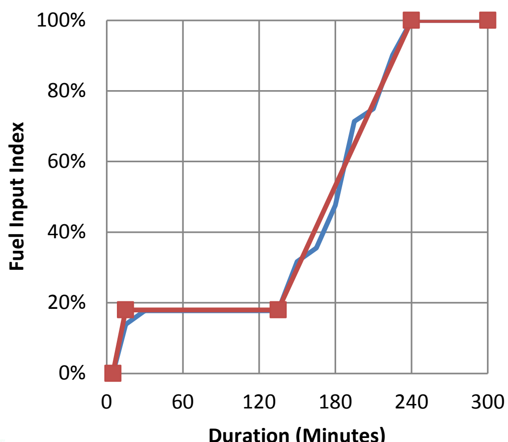
Small SCGT



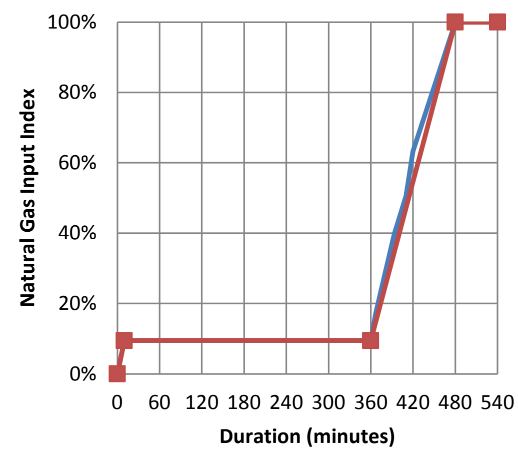
Large SCGT



CCGT



Steam Generator



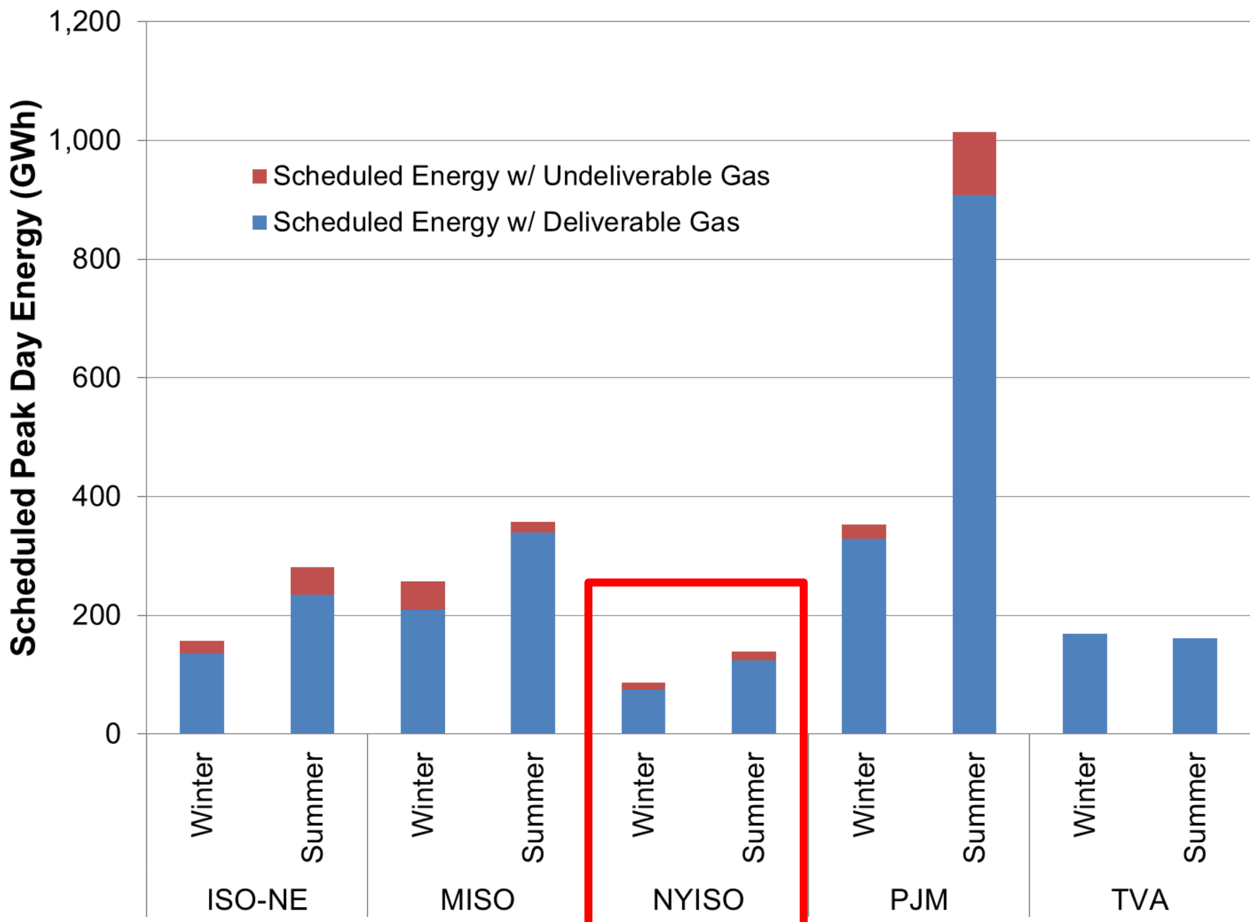
NYISO Generation Gas Demand by Pipeline

Pipeline	RGDS W18 (MDth)	RGDS S18 (MDth)	HGDS W18 (MDth)	HGDS S18 (MDth)	RGDS W23 (MDth)	RGDS S23 (MDth)
Algonquin	0	0	0	2	0	2
Dominion	72	229	208	396	445	396
Empire	138	140	151	142	132	138
Iroquois	56	300	56	401	95	389
Millennium	205	206	222	218	326	300
NFG	11	18	11	23	12	22
Tennessee	156	240	173	269	143	223
Total	**637**	**1,133**	**820**	**1,450**	**1,153**	**1,469**

Note: Does not include NYFS demands

Baseline Hydraulic Results: RGDS 2018

- Prior to any contingency, baseline pressure and flow evaluated within each PPA-specific consolidated model to determine whether full gas volumes are deliverable

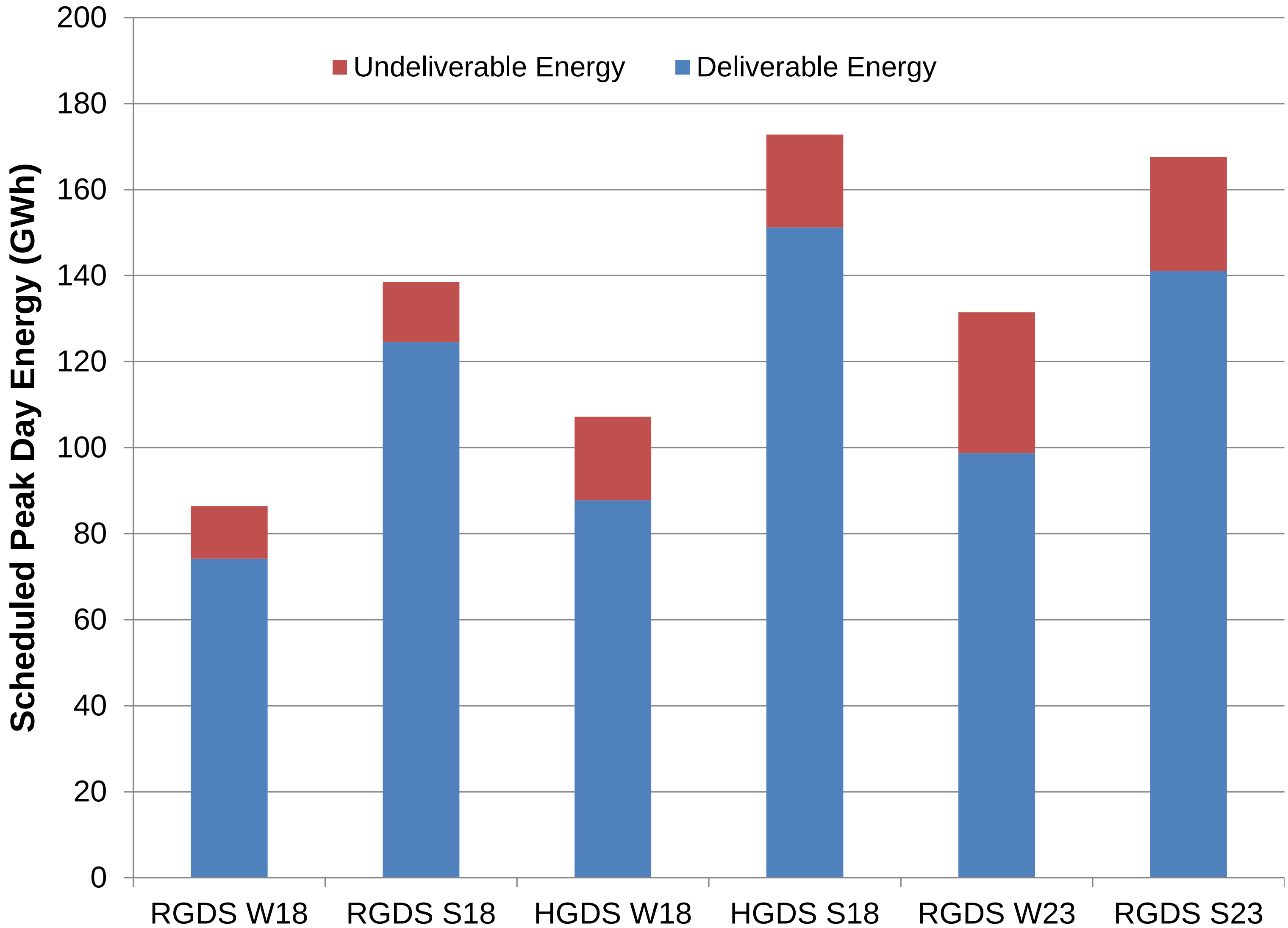


Note: Does not include NYFS

EIPC Eastern Interconnection Planning Collaborative

LEVITAN & ASSOCIATES, INC.

Baseline Hydraulic Results - NYISO



Note: Does not include NYFS

Contingency Selection

- Postulated contingencies reflect low probability, high impact events
- Selected pipeline segments exhibited congestion effects based on Target 2 results
- Identify 2-5 gas-side contingencies and 3-8 electric-side contingencies in each of six PPAs
  - Gas-side contingencies include compressor outages, pipeline ruptures, and loss of major storage deliverability
  - Electric-side contingencies include loss of transmission and major generator(s)
- Use WinTran over the 24 post-contingency hours to quantify affected generation and time-to-trip intervals

Results of Gas-Side Contingencies – Winter 2018

- Severity of the contingency event impacts characterized by short time-to-trip intervals and large quantity of affected generation
- ISO-NE exhibited most severe impacts
  - Most affected generation not dual fuel capable
- PJM (MAAC area) and NYISO (LHV / downstate) exhibited isolated pockets of affected generation
  - Substantial portion of affected generation is dual fuel capable
- MISO (North/Central), PJM (rest of RTO), TVA, IESO have less affected generation
  - Consolidated pipeline network and storage facilities provides resiliency

Results of Gas-Side Contingencies – Summer 2018

- Outside of ISO-NE and the EMAAC and SWMAAC parts PJM, network of pipeline and storage infrastructure results in negligible affected generation

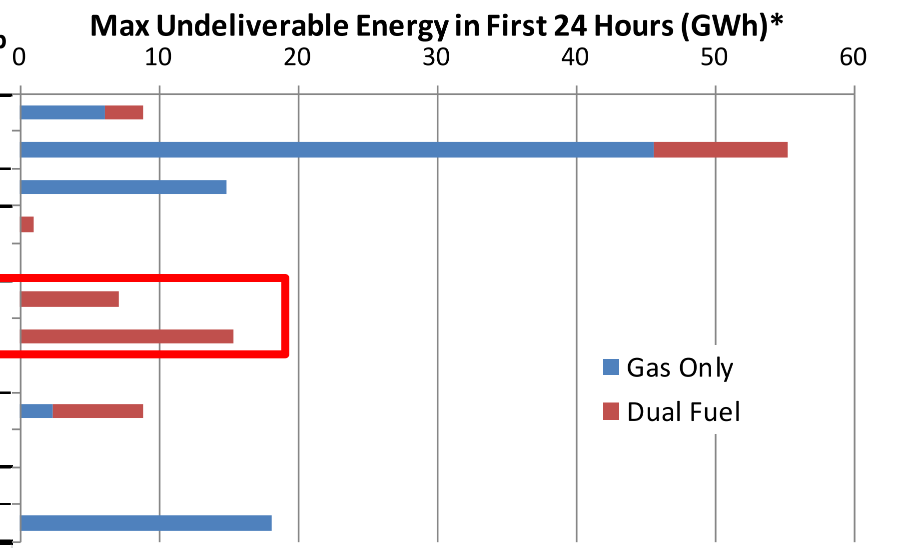
- In ISO-NE, pipeline pressure limitations potentially constrain availability of gas-fired units
  - Redispatch of other units and other electric system operator actions can mitigate impacts

Contingency Results Summary by Type

Reference Scenario, Winter 2018

Gas-Side Contingencies

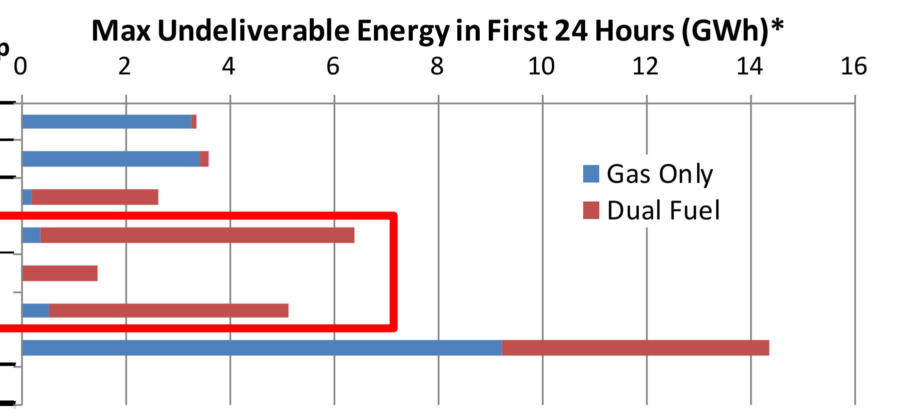
PPA	Type	# Tested	Shortest Time to Trip (h:m:s)
ISO-NE	Compression	3	3:52:47
	Line Break	3	0:11:03
	Supply	2	0:00:00
MISO	Compression	3	9:17:42
	Line Break	3	18:53:42
NYISO	Compression	3	12:22:51
	Line Break	3	0:54:20
PJM	Compression	1	None
	Line Break	6	0:03:00
	Storage	1	None
TVA	Compression	3	None
	Line Break	3	4:21:49



* Scheduled energy with undeliverable gas

Electric-Side Contingencies

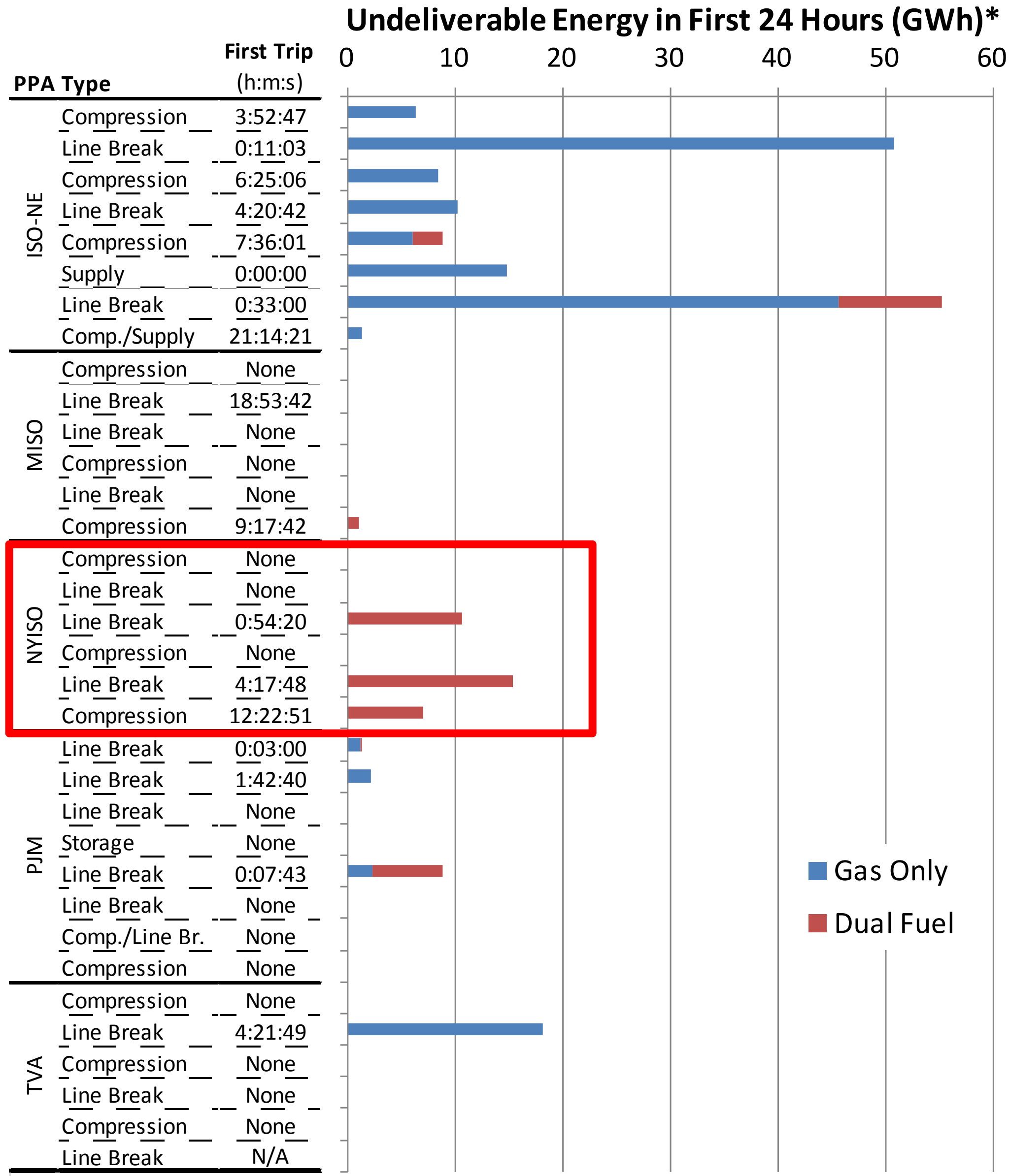
PPA	Type	# Tested	Shortest Time to Trip (h:m:s)
ISO-NE	Generation	3	None
	Transmission	2	None
MISO	Generation	8	None
NYISO	Generation	3	10:48:17
	Transmission	2	None
	Gen + Trans	1	10:50:37
PJM	Generation	3	2:45:10
TVA	Generation	5	None



* Scheduled energy with undeliverable gas

Individual Gas-Side Contingency Results

Reference Scenario, Winter 2018

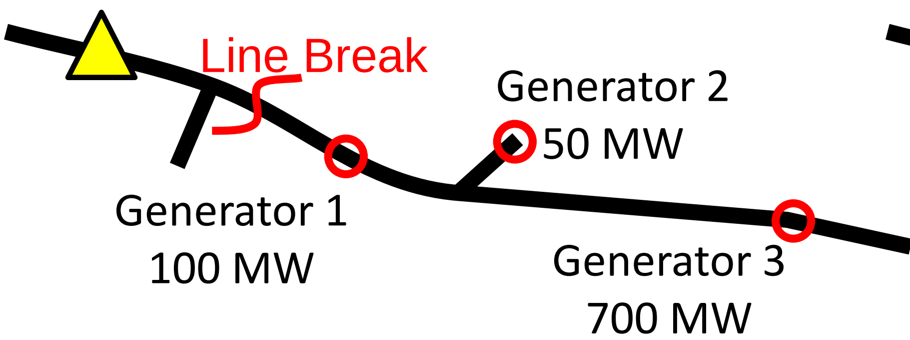


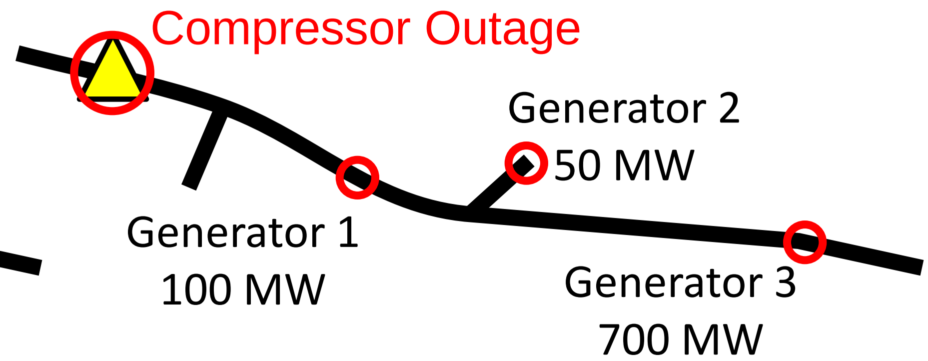
* Scheduled energy with undeliverable gas

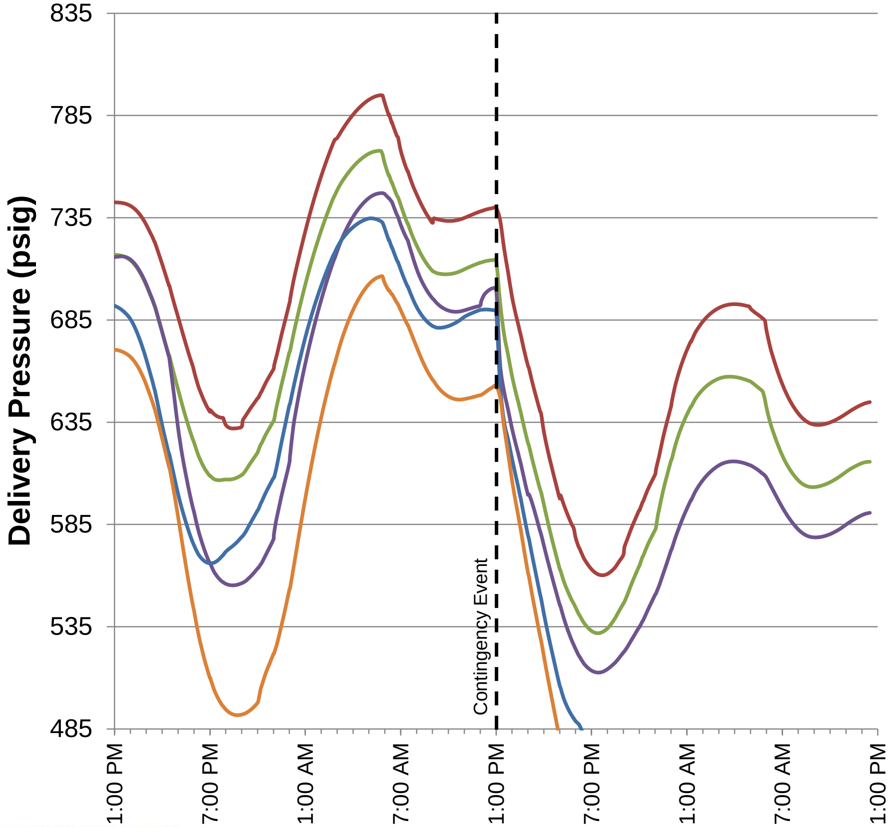
Eastern Interconnection Planning Collaborative

LEVITAN & ASSOCIATES, INC.

Example Contingency Result Outputs







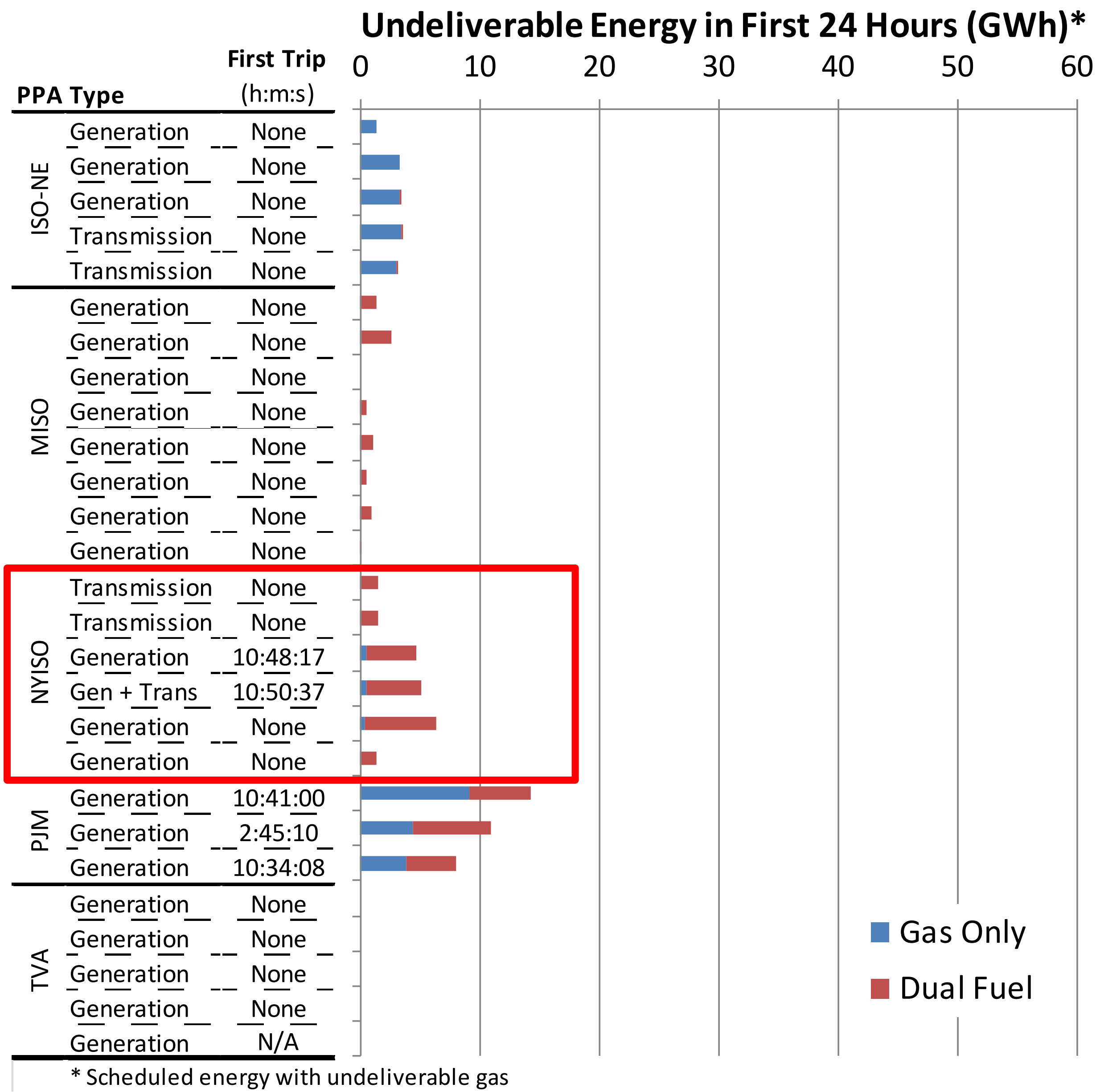
Plant	Time to Trip Following Contingency (h:m:s)	Scheduled Energy (MWh)	Undeliverable Energy (MWh)	Undeliverable Energy (%)
Plant 1	N/A	5,000	0	0
Plant 2*	3:30:00	2,500	2,200	88%
Plant 3	N/A	10,000	0	0
Plant 4*	N/A	15,000	0	0
Plant 5*	N/A	315	0	0
Plant 6	N/A	600	0	0
Plant 7	N/A	750	0	0
Plant 8	4:48:41	5,000	4,000	80%
Total			4,000 (gas only) 2,200 (dual fuel)	

Results of Electric-Side Contingencies

- Electric contingencies are largely less impactful than gas contingencies
- For RGDS W2018, results show
  - Affected generation in ISO-NE, NYISO and PJM happens many hours after the event
  - Dual-fuel capable units in MAAC portion of PJM and NYISO lessen impacts
  - Negligible affected generation in MISO, none in TVA
- For RGDS S2018, results show
  - Delivery pressures do not drop below thresholds
  - Incremental affected generation is limited to plants that are undeliverable in the baseline

Individual Electric-Side Contingency Results

Reference Scenario, Winter 2018



EIPC Eastern Interconnection Planning Collaborative

LEVITAN & ASSOCIATES, INC.

LDC Contingency Analysis Approach

- Evaluation at specific temperatures rather than peak day
  - On a peak day, interruptible service typically not available to generators
- Evaluation by LAI (Central Hudson Gas & Electric, New Jersey Natural Gas, Public Service Electric & Gas, Washington Gas Light)
  - LDCs provided hydraulic details of segments that serve generation
  - Segments added to regional hydraulic models
  - Results and assessment reviewed with LDCs
- Evaluation by LDC (Con Edison, National Grid, Baltimore Gas & Electric, Nicor Gas, Peoples Gas, Enbridge Gas, Union Gas)
  - LAI provided generator gas demands to LDCs
  - LDCs provided results to LAI
  - Assessment reviewed with LDCs

Contingency Mitigation

- Intrinsic – Gas operator actions included as part of the model solutions
  - Use of line-pack
  - Increased interconnect flows from neighboring pipelines
  - Increased utilization of spare horsepower from downstream compression stations
  - Reversal-of-flow across key pipeline segments
- Extrinsic – Considered in the analysis but not included in the model solutions
  - Electric redispatch and switching to dual fuel
  - Communication initiatives among the PPAs, pipelines and/or LDCs
  - Select pipeline tariff innovations
  - Continued efforts to promote harmonization of gas day and electric day scheduling procedures

Target 4

Fuel Assurance: Dual Fuel Capability and Firm Transportation Alternatives

Primary Findings

- *New* gas-fired plants are expected to use ULSD as the primary back-up fuel
- Anticipated heavy reliance on ULSD represents a major change in the distillate oil market – ULSD supply chain is robust
- Air permits typically cap oil use to 720 hours, but some permits have established lower annual hourly limits
- At most locations, the cost of dual-fuel capability is much less expensive than the incremental cost of FT to satisfy the fuel assurance objective

Fuel Assurance Analysis Approach

- Identify constrained locations across the Study Region from Target 2 F-D results
  - NYISO locations: NYC, Long Island, LHV, Capital District
- Define gas turbine technology types in SC and CC mode
- Design cost model to account for regional differences in dual-fuel capability and incremental FT
  - Account for non-firm transportation costs
  - Account for local facility improvements where applicable

Incremental FT Cost Inputs

- Identification of a pipeline path from a production basin to plant location
- FT reservation rates for incremental capacity
- Avoided cost of non-firm transportation
- Lateral as proxy for LDC transportation costs (where applicable)
- # of days with interrupted non-firm service (Target 2)

Incremental FT Paths for NYISO Locations

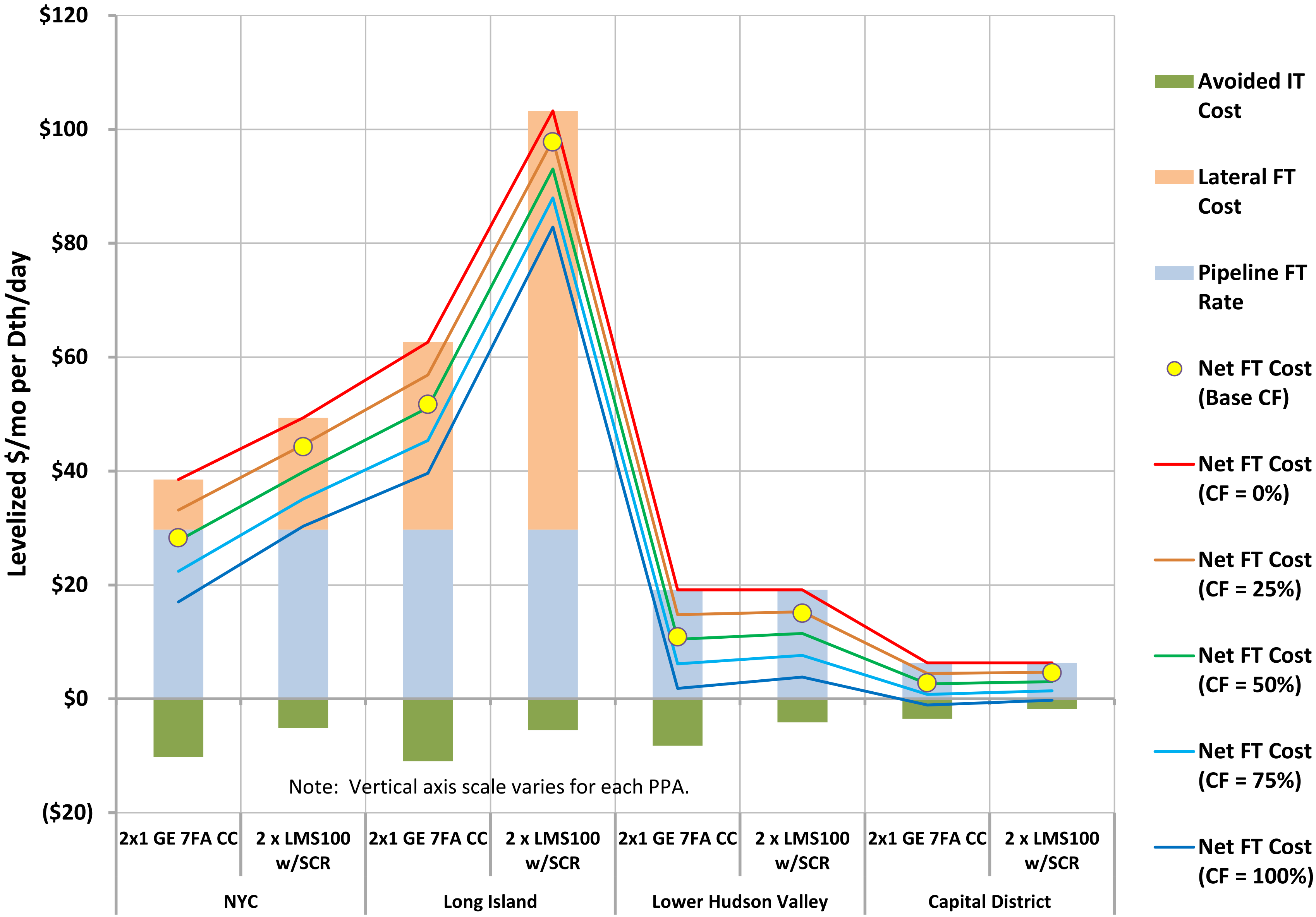
Location	Pipeline	Expansion Project	FERC Docket	Total Rate ($/Dth-mo.)	Supply Basin
New York City	Constitution	New pipeline	CP13-499	30.72*	Marcellus/Utica
	Iroquois				
Long Island	Constitution	New pipeline	CP13-499	30.72*	Marcellus/Utica
	Iroquois				
Lower Hudson Valley	Millennium	Hancock Compressor	CP13-14	19.77**	Marcellus/Utica
Capital District	Tennessee	Northeast Supply Diversification	CP11-30	6.52	Marcellus/Utica

* For both Long Island and New York City, the total rate is the sum of the Constitution rate filed in CP13-499 plus the current effective tariff rate on Iroquois.

** The most recent project on Millennium, the Hancock Compressor Station Project, did not lead to an increase in rates. Therefore the FT-1 rate was utilized.

Location	Pipeline Connection	LDC Connection Proxy Project	Length (miles)	Estimated Cost (2018$ MM)
New York City	Iroquois	Eastchester Extension	0.8 (onshore) / 1.7 (marine)	$69.2
Long Island	Iroquois	Eastern Long Island Expansion	12 (onshore) / 17 (marine)	$259.0

Net Cost of FT – NYISO Locations



Dual-Fuel Capability Permitting

- Limitations on back-up fuel use
  - Air permit conditions limit annual hours on oil – most common limit is 720 but some recent permits are less
  - Local zoning conditions govern construction of on-site oil storage tanks, tanker truck delivery routes
- Converting gas-only to dual-fuel requires permit modifications
  - May require existing pollution controls to be upgraded
  - Cost to retrofit typically higher than to incorporate dual-fuel capability at initial construction
- Air permits comply with state/federal NSR/PSD rules
  - Attainment v. non-attainment locations for pollutants
  - Best Achievable Control Technology / Lowest Achievable Emission Rate standards

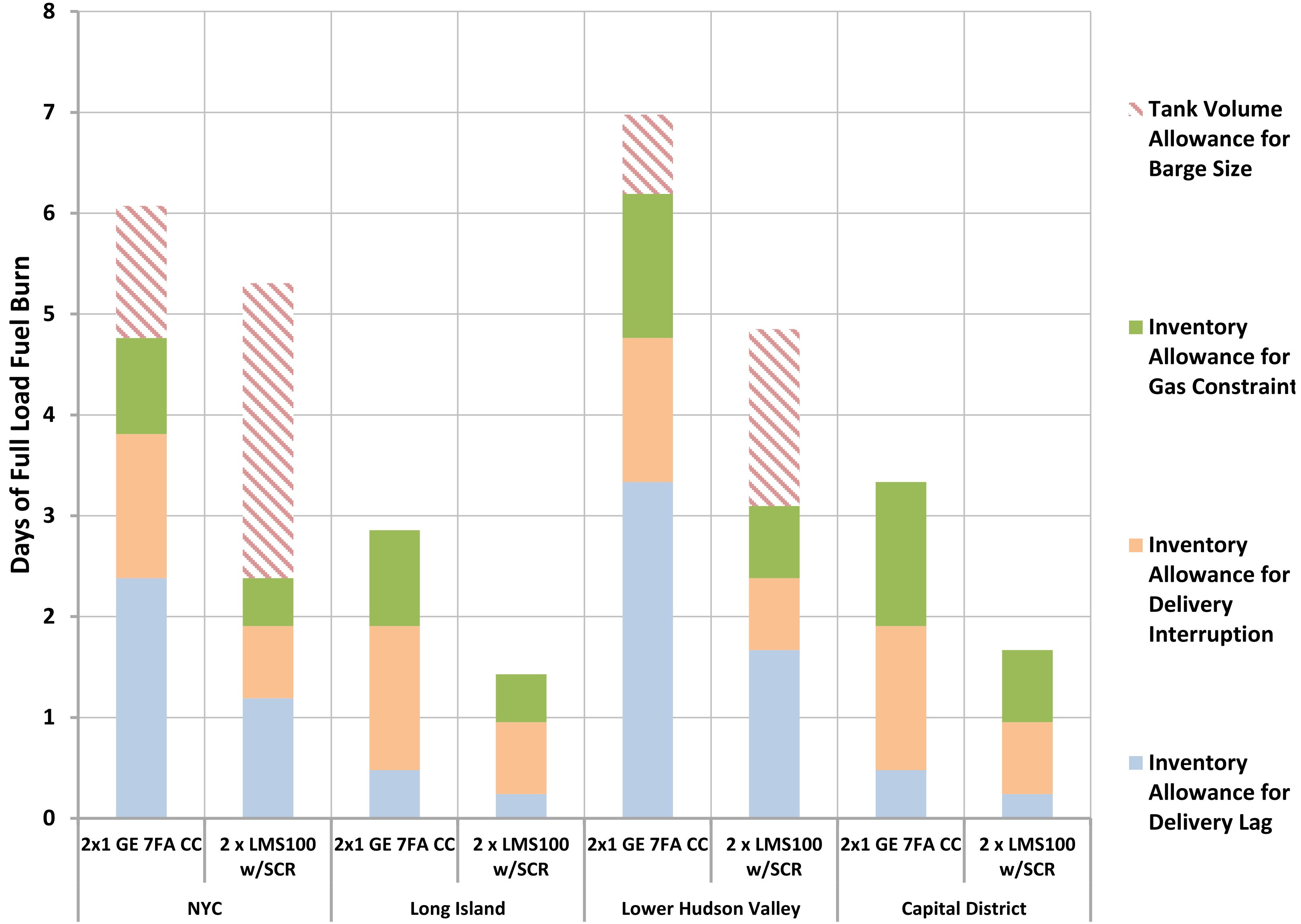
Dual-Fuel Capability Cost Inputs

- ULSD logistics by location
  - Depot identification
  - Transport mode (truck or barge)
  - New price based on rack price, shipping, demurrage
  - Labor cost factor and tax rates
  - Permit restrictions
- Target inventory and fuel storage tank volume
  - Expressed in days of full load burn
  - Location-specific variables
    - Severity of natural gas delivery constraint
    - Delivery lag (order to receipt) and potential weather delays
    - Expected capacity factor when operating on ULSD
    - Tank volume allowance for “lumpy” barge delivery size

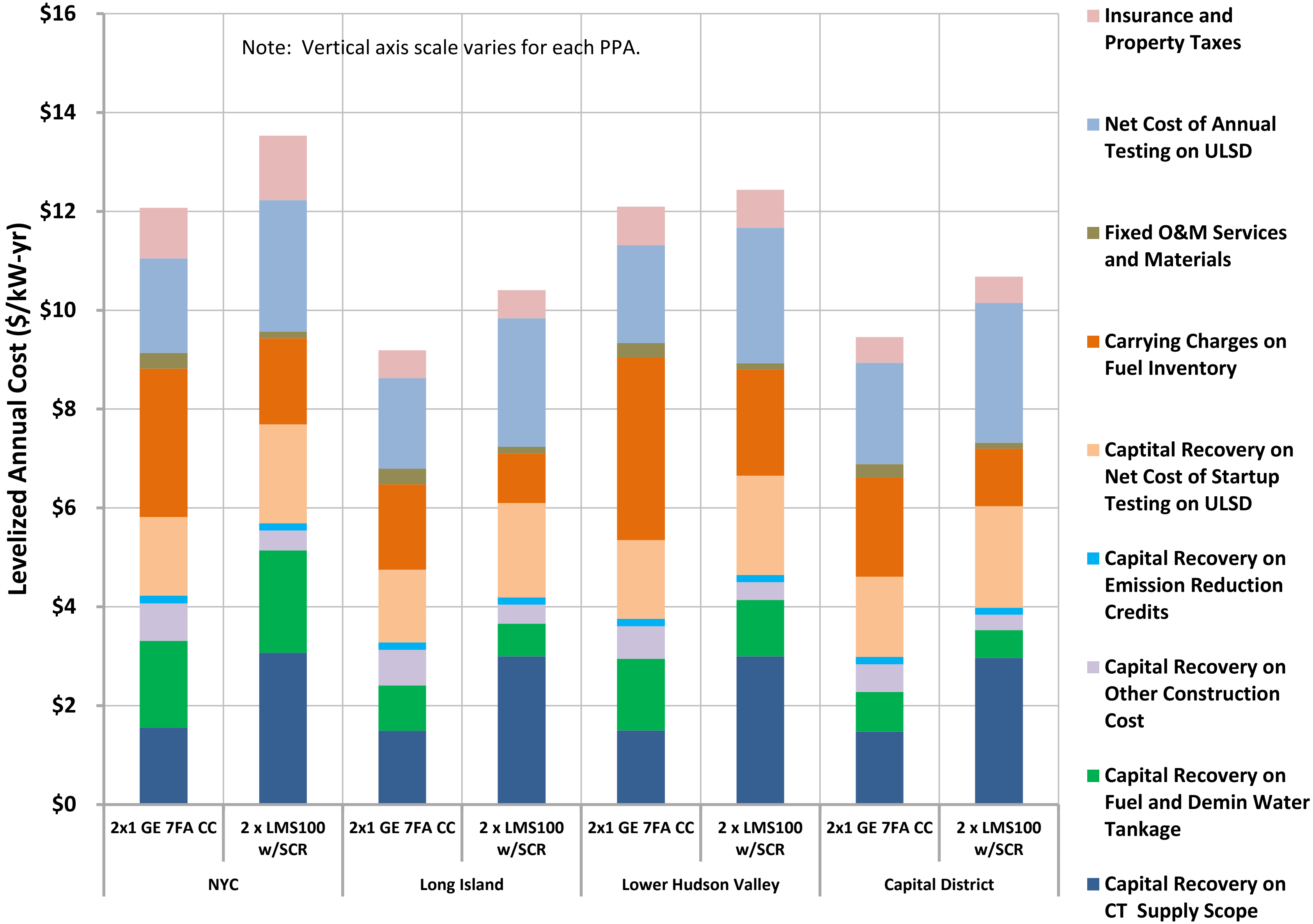
ULSD Logistics by NYISO Location

Location	Depot Location	Rack Price ($/gal)	Delivery Mode	Delivery Cost ($/gal)
New York City	NY Harbor	$2.74	Barge	$0.00
Long Island	Inwood, NY	$2.78	Truck	$0.05
Lower Hudson Valley	NY Harbor	$2.74	Barge	$0.05
Capital District	Albany, NY	$2.80	Truck	$0.04

Fuel Tank Size Calculations – NYISO Locations



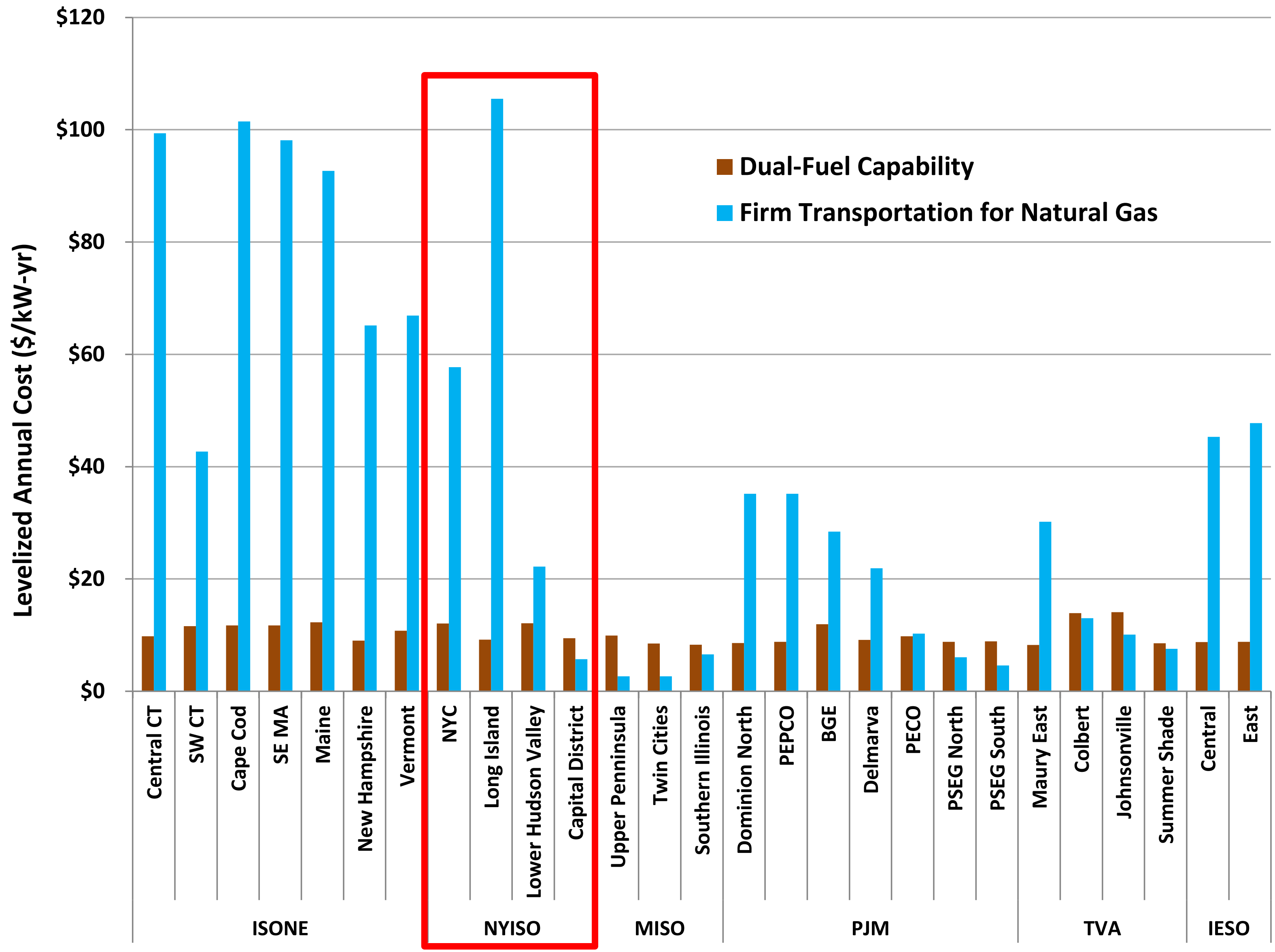
Dual Fuel Cost Details for NYISO Locations



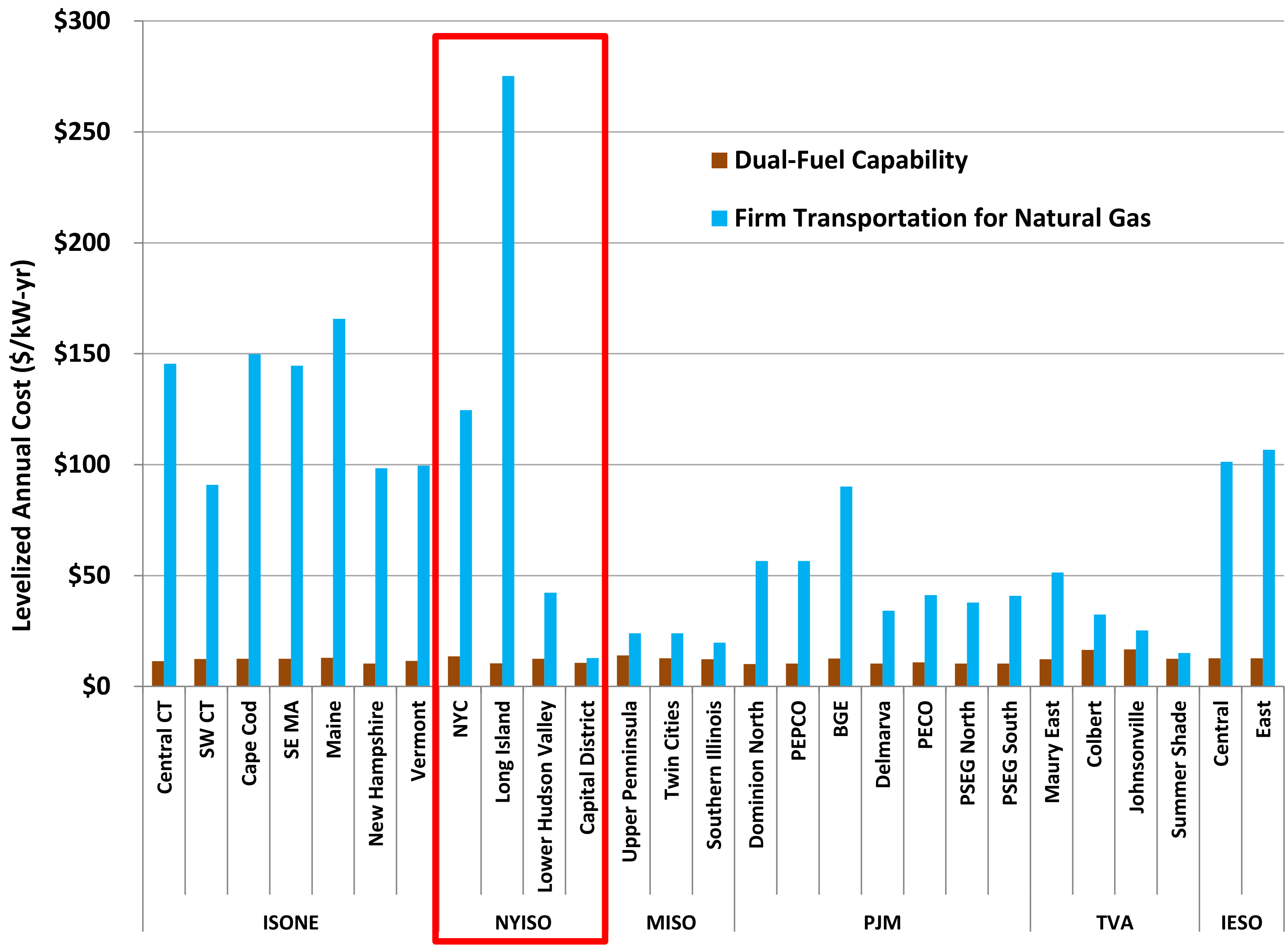
Fuel Assurance Analysis Results

- Cost of dual-fuel capability generally similar across locations
  - Variations between barge- and truck-supplied locations
- Cost of incremental FT varies across Study Region
  - Expensive in New England due to existing bottlenecks
  - Expensive at the local level (NYFS, in particular)
- Dual-fuel capability typically much lower cost for a new combined-cycle (CC) plant than FT; far more pronounced for simple cycle (SC) plants
  - LDC-served generators additionally incur local facility improvement costs
  - Restrictive environmental permit requirements limit liquid fuel usage
  - Structural changes continue to improve ULSD replenishment logistics

Fuel Assurance Analysis: Combined Cycle



Fuel Assurance Analysis: Simple Cycle



Study Limitations

- Fuel assurance from PPAs' perspective
- No quantification of wholesale energy price effects with incremental FT v. dual-fuel capability
- Other factors affecting generators' willingness to invest in incremental FT
  - Different performance on gas v. ULSD
  - Profit margin, incl. potential hits to EBITDA
  - Margin recoupment from FT capacity release
  - Increased permitting difficulty to store and burn ULSD
  - Penalty avoidance as a capacity resource