Attachment IV

Exhibit 25

Alternative Methods for Determining LCRs

Zachary Stines
Associate Market Design Specialist

Installed Capacity Working Group

September 28, 2017, NYISO

NEW YORK INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY

Agenda

- **Phase 2: Refining the Methodology**
  - Accounting for Unavailability
  - Preliminary Results and Assumptions
  - Optimization Results with Preliminary Transmission Security
- **Phase 3: Market Simulations**
  - Initial Results
- **Phase 4: Defining Process**
  - Timeline
- **Next Steps**
- **Questions**

Phase 2: Transmission Security

NEW YORK INDEPENDENT SYSTEM OPERATOR

N-1-1 Transmission Security

- Required by NERC, NPCC, and NYSRC for designing the system
- N-1-1 analysis is performed using a NYCA coincident peak powerflow case
  - Snapshot in time: A single NYCA-wide generator dispatch to secure all Bulk Power Transmission Facilities (BPTFs)
- A reliability criteria violation is identified when any allowable re-dispatch of the system cannot alleviate a thermal overload
  - If overloads occur, system is dispatched to minimize overloads

Transmission Security Methodology

- N-1-1 analysis was conducted to determine the transmission security import limits into each Locality
- These import limits were used to determine the minimum available capacity required for each Locality
- To translate this minimum available capacity into a market requirement the methodology needs to account for capacity unavailability
- To account for capacity unavailability, the 5-year zonal EFORd was used to calculate minimum locational capacity requirements

Example Calculation

Transmission Security Requirements	Formula	Zone X
Load Forecast (MW)	[A] = Given	12,000
Transmission Security Import Limit (MW)	[B] = Given	1,500
Transmission Security UCAP Requirement (MW)	[C] = [A]-[B]	10,500
Transmission Security UCAP Requirement (%)	[D] = [C]/[A]	87.5%
5 Year EFORd (%)	[E] = Given	8.0%
Transmission Security ICAP Requirement (MW)	[F] = [C]/(1-[E])	11,413
Transmission Security LCR Floor (%)	[G] = [F]/[A]	**95.1%**

NEW YORK INDEPENDENT SYSTEM OPERATOR

Accounting for Unavailability

Translation to account for Unavailability

- **Unavailability is accounted for in**
  - Previous study on locational requirements[1]
    - Established the historical basis for the 80% in-city requirement
  - Other ISO/RTOs (*i.e.*, ISO-NE)

[1]"In-City Capacity Requirement Study", Stone & Webster, 1996

NEW YORK INDEPENDENT SYSTEM OPERATOR

ISO-NE Local Sourcing Requirements

- Local Sourcing Requirements (LSR) for an import-constrained zone is the amount of capacity needed to satisfy "*the higher of*" either (i) the Local Resource Adequacy (LRA) or (ii) the Transmission Security Analysis (TSA)[2]

[2]"ISO New England Installed Capacity Requirement, Local Sourcing Requirements and Capacity Requirement Values for the System-Wide Capacity Demand Curve for the 2019/20 Capacity Commitment Period", ISO New England Inc., January 2016 , available at: https://www.iso-ne.com/static-assets/documents/2016/01/icr_values_2019_2020_report_final.pdf

DRAFT – FOR DISCUSSION PURPOSES ONLY

ISO-NE Transmission Security Analysis

- A deterministic reliability screen of a transmission import-constrained area
- Determines the requirements of the sub-area in order to meet its load through internal generation and import capacity

NEW YORK INDEPENDENT SYSTEM OPERATOR

ISO-NE Transmission Security Analysis

$$TSA\ Requirement = \frac{(Need - Import\ Limit)}{1 - (Assumed\ Unavailable\ Capacity/Existing\ Resources)}$$

- Explicitly accounts for the unavailability of capacity prior to making it a market requirement
- The forced outage of fast-start (peaking) generation is based on an assumed value of 20% for the analysis instead of being based on historical five-year average generating unit performance

NEW YORK INDEPENDENT SYSTEM OPERATOR

NYISO Transmission Security Methodology Proposal

- Based on
  - Peak load within the locality (*i.e.*, need)
  - N-1-1 import limit into the locality
  - Locality 5 year EFORd (*i.e.*, unavailability)
- Determines the minimum capacity market requirement for the localities
- These minimum market requirements are used as LCR floors within the optimization

Preliminary Results and Assumptions

Preliminary Transmission Security LCR Floors

Transmission Security Requirements	G-J	Zone J	Zone K
Load Forecast (MW)	16,061	11,670	5,427
Transmission Security Import Limit (MW)	3,250	3,250	400
Transmission Security UCAP Requirement (MW)	12,811	8,420	5,027
Transmission Security UCAP Requirement (%)	79.76%	72.15%	92.63%
5 Year EFORd (%)	10.50%	9.99%	10.06%
Transmission Security ICAP Requirement (MW)	14,314	9,355	5,589
Transmission Security LCR Floor (%)	**89.12%**	**80.16%**	**102.99%**

*Values are preliminary and subject to change

NEW YORK INDEPENDENT SYSTEM OPERATOR

Preliminary Transmission Security LCR Floors

	Zone J LCR	G-J LCR	Zone KLCR
Preliminary Transmission Security LCR Floors	80.16%	89.12%	102.99%

- These values are preliminary and subject to change
- These preliminary floors are used in the market simulation analysis and will be utilized in the consumer impact assessment

Overview of Preliminary Analysis

- Analyzed the N-1-1 thermal transfer limits for the NYCA interfaces associated with the G-J, Zone J, and Zone K Localities
- Used the final Summer 2017 Operating base case
  - Rebuilt case to conduct the N-1-1 analysis
  - PARS and Generation Dispatch maintained initial schedule in analysis

Line Rating Assumptions

- The G-J Locality and Zone K were calculated assuming Long Term Emergency (LTE) ratings
  - Consistent with NYISO Normal Operating and planning criteria
- Zone J was calculated assuming Normal line ratings
  - Based on NYSRC Local Reliability Rule (G1)

Boundary Assumptions

- The analysis calculates the N-1-1 transmission security import limits using the NYCA bulk power transmission facilities (BPTF) into each Locality
  - Zone J: Dunwoodie South interface
  - Zone K: ConEd-LIPA interface
  - G-J: UPNY-SENY interface
- The external transmission facilities are not incorporated in the analysis since these facilities cannot meet the Locality capacity requirements

NEW YORK INDEPENDENT SYSTEM OPERATOR

UPNY-SENY

Name	Line ID	Voltage (kV)
Mohawk (Zone E) – Hudson Valley (Zone G)		
Coopers Corners-Middletown*	CCRT34	345
Coopers Corners-Dolson Ave*	CCDA42	345
West Woodbourne 115/69	T152	115/69
Capital (Zone F) – Hudson Valley (Zone G)		
Athens-Pleasant Valley*	91	345
Leeds-Pleasant Valley*	92	345
*Leeds-Hurley Ave.	301	345
Hudson-Pleasant Valley*	12	115
Blue Stores E-Pleasant Valley*	13-987	115
Blue Stores W-Pleasant Valley*	8	115
*Feura Bush-North Catskill	2	115

* Indicates the metered end of the circuit

NEW YORK INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY

Dunwoodie South

Name	Line ID	Voltage (kV)
Dunwoodie (Zone I) – NYC (Zone J)		
*Dunwoodie-Mott Haven	71	345
*Dunwoodie-Mott Haven	72	345
Sprain Brook-Tremont*	X28	345
*Sprain Brook-West 49th Street	M51	345
*Sprain Brook-West 49th Street	M52	345
*Sprain Brook-Academy	M29	345
*Dunwoodie-Sherman Creek	99031	138
*Dunwoodie-Sherman Creek	99032	138
*Dunwoodie-East 179th Street	99153	138
Long Island (Zone K) – NYC (Zone J)		
*Lake Success-Jamaica	903	138
*Valley Stream-Jamaica	901L_M	138

* Indicates the metered end of the circuit

ConEd – LIPA

Name	Line ID	Voltage (kV)
Dunwoodie (Zone I) – Long Island (Zone K)		
*Dunwoodie-Shore Road	Y50	345
*Sprain Brook-East Garden City	Y49	345
NYC (Zone J) – Long Island (Zone K)		
Jamaica-Valley Stream*	901L_M	138
Jamaica-Lake Success*	903	138

* Indicates the metered end of the circuit

Treatment of UDRs

- UDRs are treated as supply-side resources and at a level consistent with their elections
- UDRs are not considered as part of the import capability when calculating the N-1-1 import limits

NEW YORK INDEPENDENT SYSTEM OPERATOR

N-1-1 Base Case

- Updated Summer 2017 Operating base case
  - Inclusion of transmission and generation facility additions and retirements
- All system elements modeled as in service
- All generation represented

NEW YORK INDEPENDENT SYSTEM OPERATOR

Contingencies

- **In the N-1-1 analysis**
  - 1st Contingency: Removal of the most limiting single element contingency
  - 2nd Contingency: NPCC defined contingency

Zone J Contingencies

Limiting Element	Rating	Limiting Contingency
(2) Mott Haven – Rainey (Q11) 345 kV	@NORM 707 MW L/O	Mott Haven – Rainey (Q12) 345 kV
(3) Mott Haven – Rainey (Q11) 345 kV	@NORM 707 MW L/O	(SB: Sprain Brook 345 RS4) Sprain Brook – W. 49th St. (M52) 345 kV Sprain Brook 345/138 Transformer BKS6

Zone K Contingencies

Limiting Element	Rating	Limiting Contingency
Dunwoodie – Shore Rd. (Y50) 345 kV	@LTE 914 MW[3] L/O	Sprain Brook – East Garden City (Y49) 345 kV
Dunwoodie – Shore Rd. (Y50) 345 kV	@LTE 914 MW[3] L/O	New Bridge – Duffy Ave. (501) 345 kV

[3] LIPA rating for Y50 circuit is based on 70 % loss factor and rapid oil circulation.

G-J Contingencies

Limiting Element	Rating	Limiting Contingency
(1) Leeds – Pleasant Valley (92) 345 kV	@LTE 1538 MW L/O	Athens – Pleasant Valley (91) 345 kV
(2) Leeds – Pleasant Valley (92) 345 kV	@LTE 1538 MW L/O	(SB: East Fishkill 345 #5) Roseton – East Fishkill (RFK305) 345 kV East Fishkill 345/115 kV Transformer BK1

NEW YORK INDEPENDENT SYSTEM OPERATOR

Optimization with Transmission Security

Base Case with Transmission Security Limits

Scenario	Zone J LCR	Zone K LCR	G-J LCR	Cost ($ million)
Current LCR Methodology	81.4%	103.2%	91.3%	$4,441.90
Refined Optimized Methodology without Transmission Security Limits (TSL)	78.0%	105.3%	91.5%	$4,402.89
Refined Optimized Methodology with Transmission Security Limits (TSL)	80.16%	104.15%	90.71%	$4,424.37

NEW YORK INDEPENDENT SYSTEM OPERATOR

Base Case with Transmission Security Limits

Scenario	Zone J LCR	Zone K LCR	G-J LCR
Current LCR Methodology	9,495 MW	5,603 MW	14,664 MW
Refined Optimized Methodology without Transmission Security Limits (TSL)	9,102 MW	5,715 MW	14,696 MW
Refined Optimized Methodology with Transmission Security Limits (TSL)	9,355 MW	5,652 MW	14,570 MW

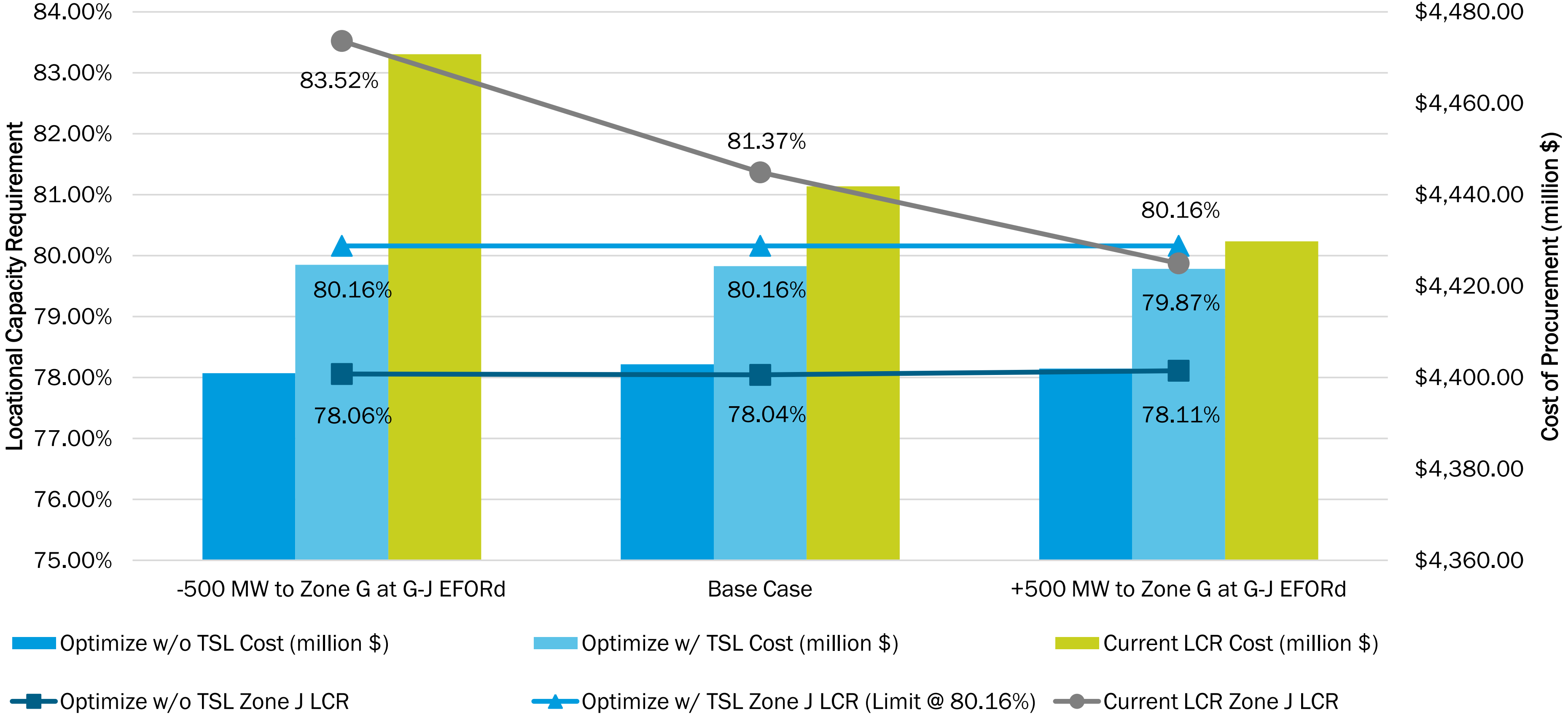
Phase 3: Market Simulations

Market Simulation Sensitivities

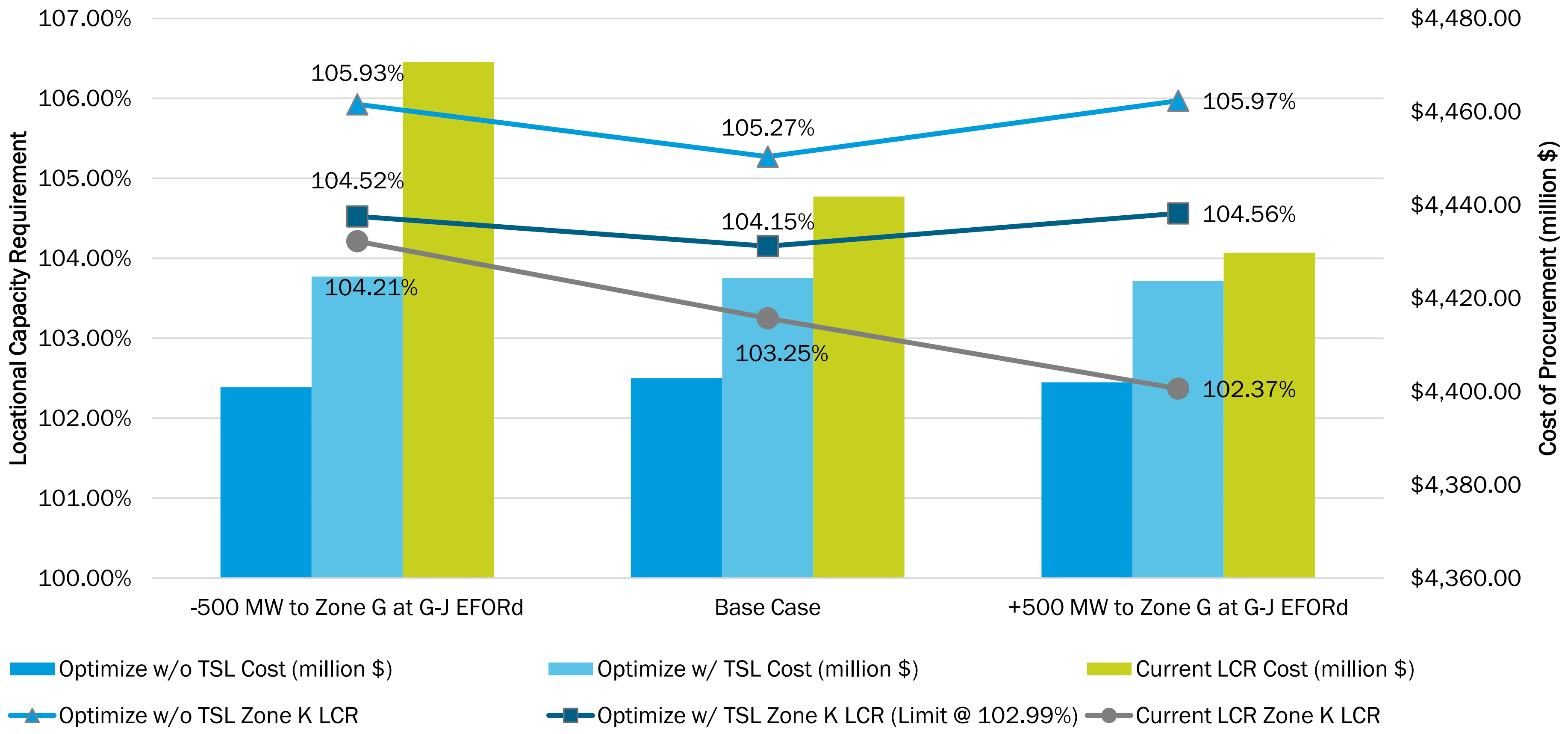
- +/- 500 MW to Zone G at G-J EFORd
- +/- 500 MW to Zone J at J EFORd
- +/- 500 MW to Zone K at K EFORd
- +/- 500 MW to Zone F at F EFORd

Market Simulations: +/- 500 MW to Zone G

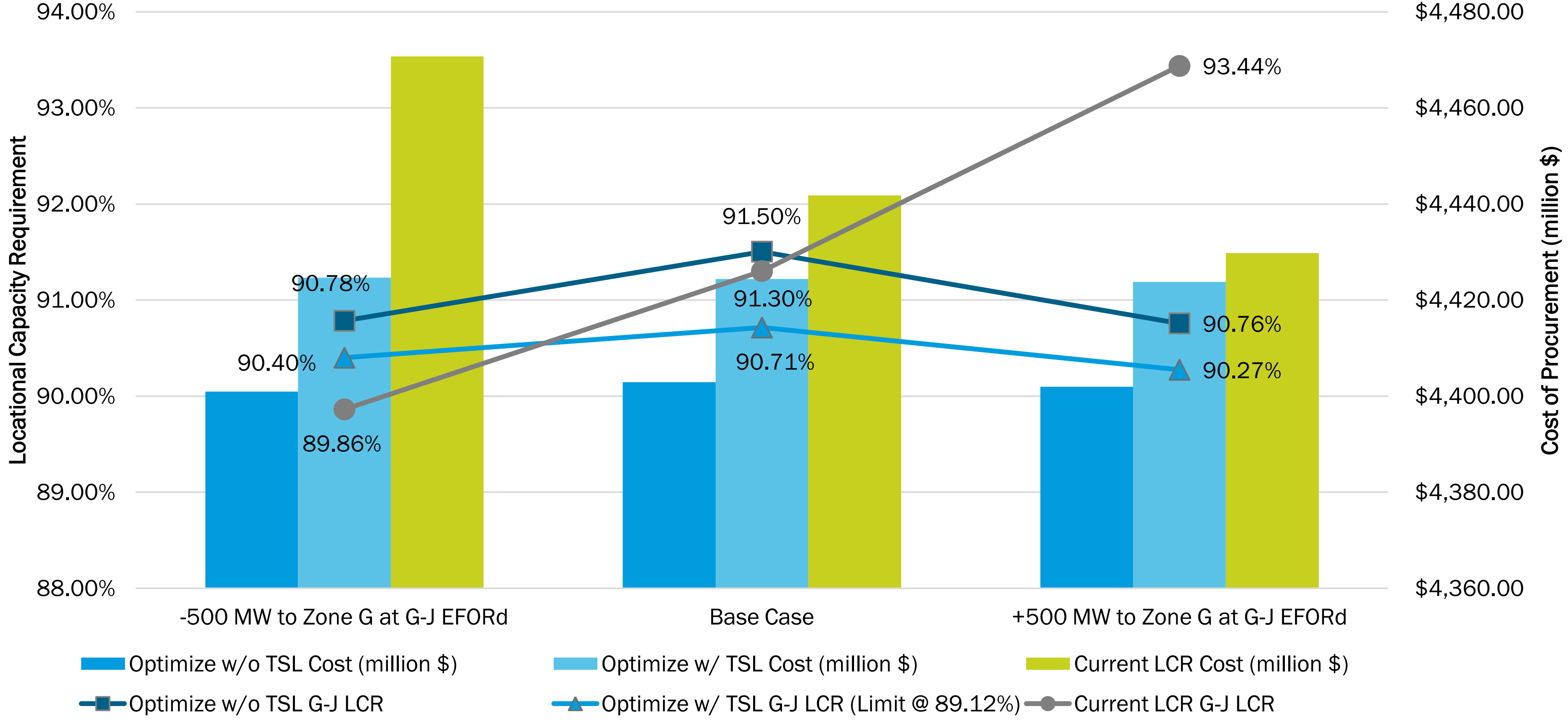
Addition and Removal of Capacity from Zone G Zone J LCR



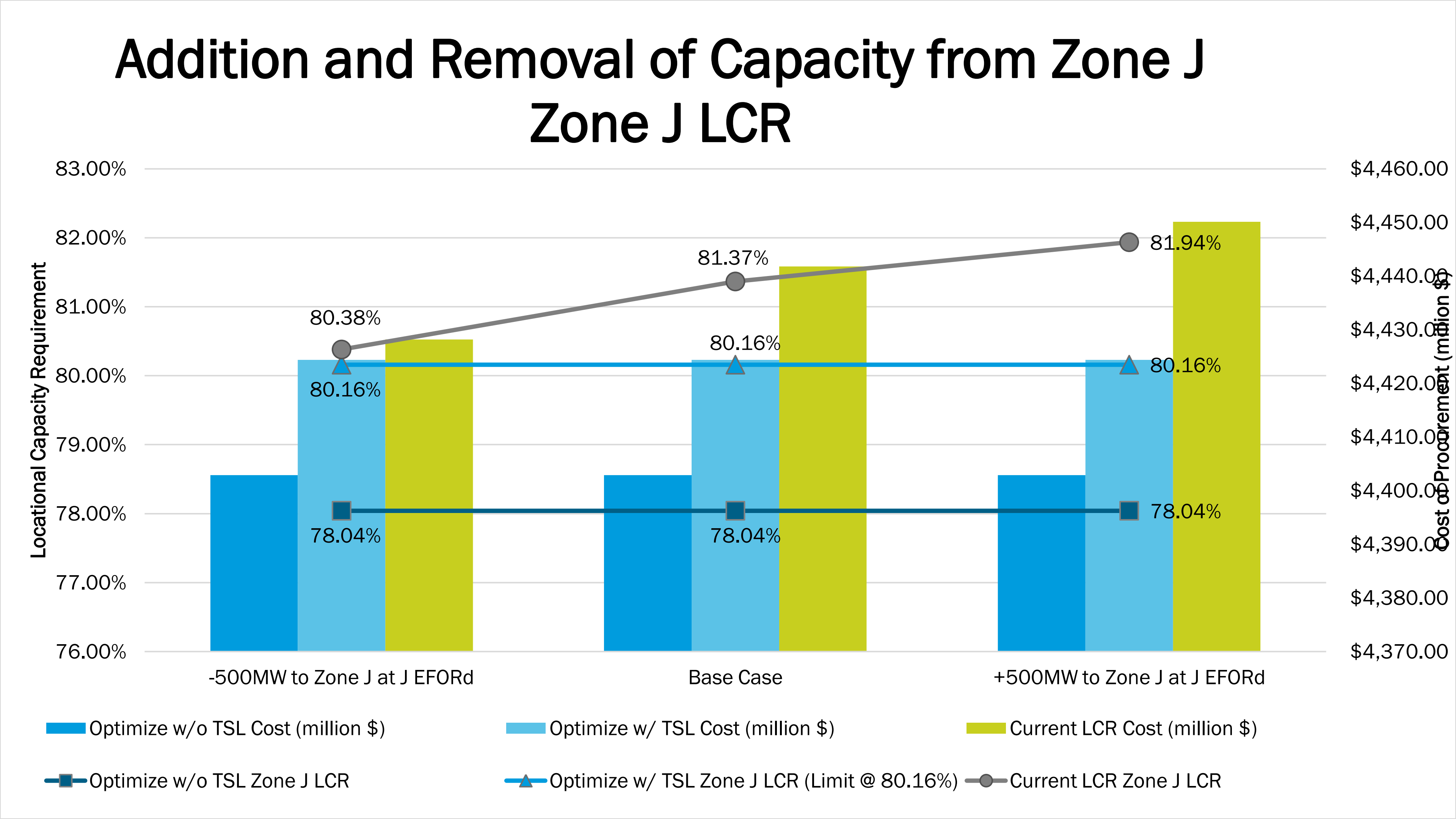
Addition and Removal of Capacity from Zone G Zone K LCR



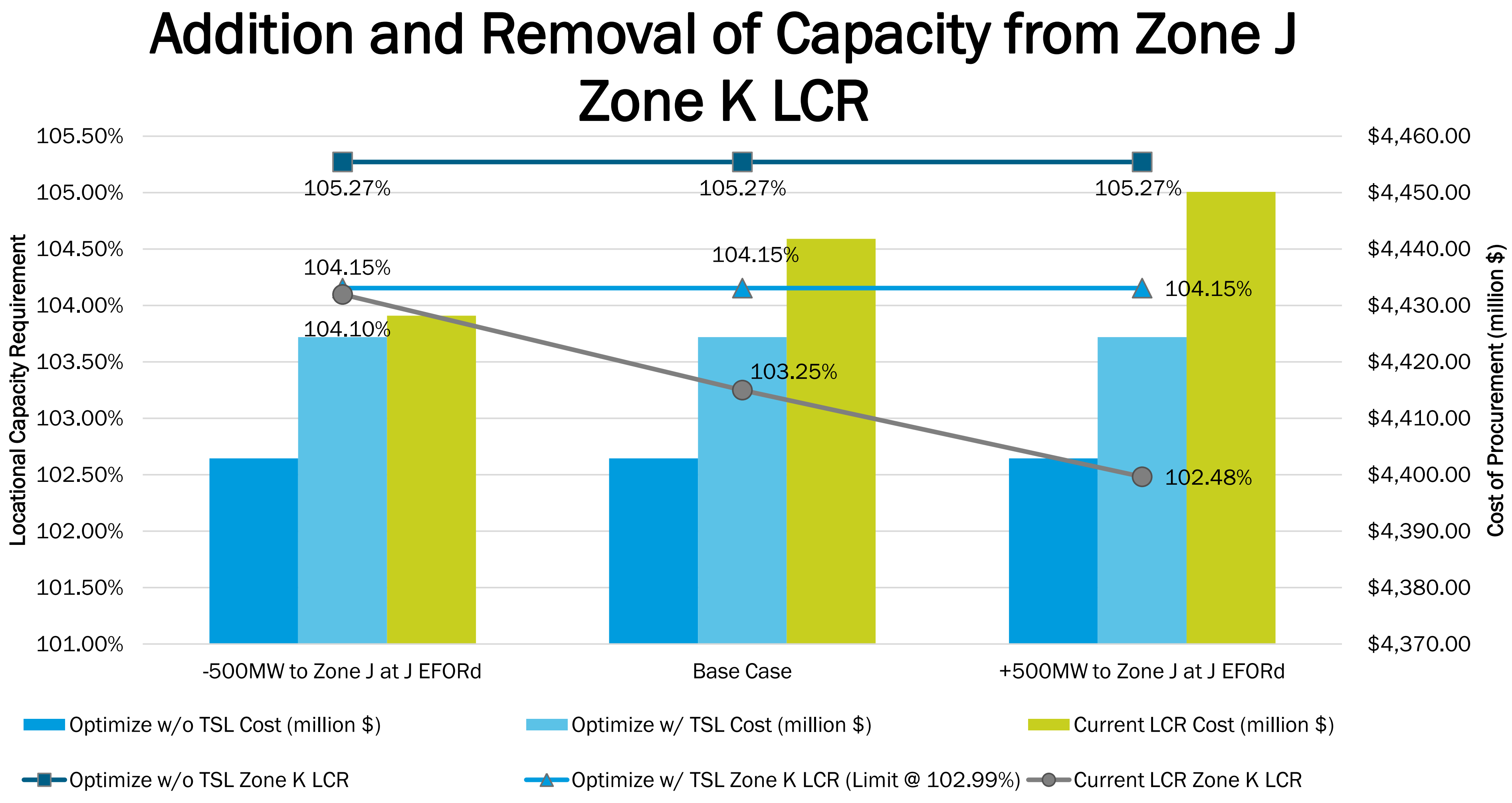
Addition and Removal of Capacity from Zone G
G-J LCR

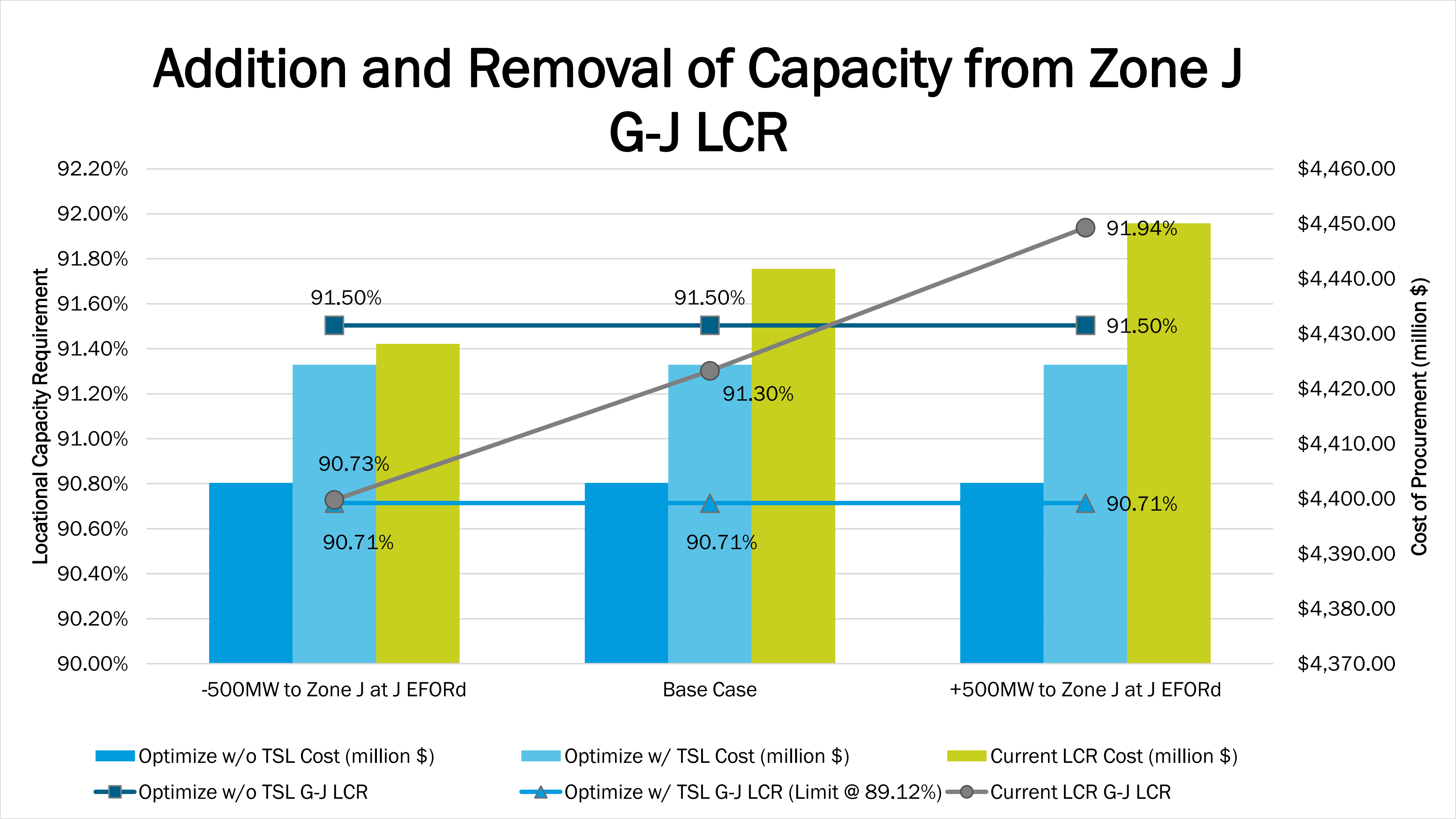


Market Simulations: +/- 500 MW to Zone J

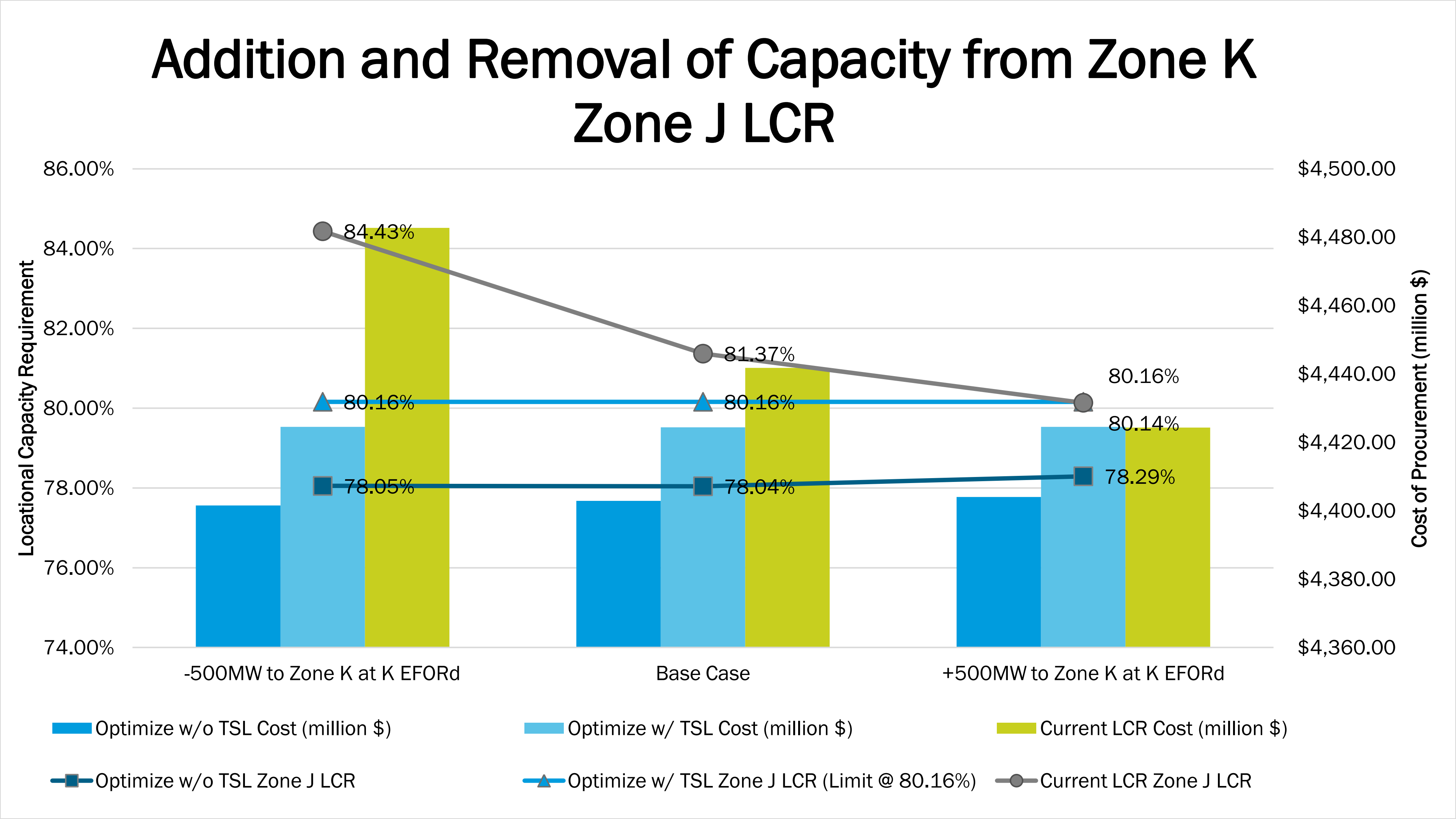


Addition and Removal of Capacity from Zone J
Zone J LCR
83.00%
82.00%
81.00%
80.00%
79.00%
78.00%
77.00%
76.00%
Locational Capacity Requirement
$4,460.00
$4,450.00
$4,440.00
$4,430.00
$4,420.00
$4,410.00
$4,400.00
$4,390.00
$4,380.00
$4,370.00
Cost of Procurement (million $)
80.38%
81.37%
81.94%
80.16%
80.16%
80.16%
78.04%
78.04%
78.04%
-500MW to Zone J at J EFORd
Base Case
+500MW to Zone J at J EFORd
Optimize w/o TSL Cost (million $)
Optimize w/ TSL Cost (million $)
Current LCR Cost (million $)
Optimize w/o TSL Zone J LCR
Optimize w/ TSL Zone J LCR (Limit @ 80.16%)
Current LCR Zone J LCR

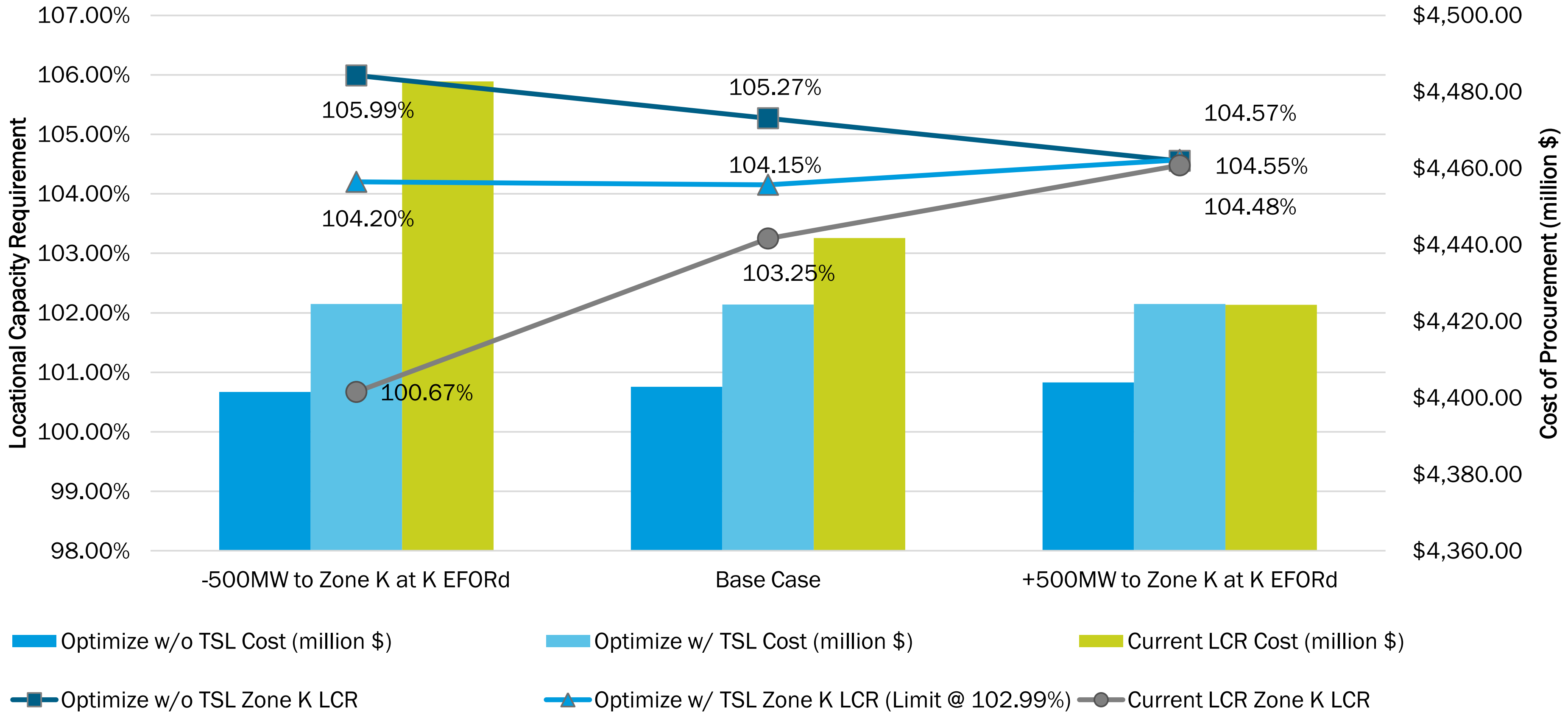

Addition and Removal of Capacity from Zone J
Zone K LCR
105.50%
105.00%
104.50%
104.00%
103.50%
103.00%
102.50%
102.00%
101.50%
101.00%
Locational Capacity Requirement
$4,460.00
$4,450.00
$4,440.00
$4,430.00
$4,420.00
$4,410.00
$4,400.00
$4,390.00
$4,380.00
$4,370.00
Cost of Procurement (million $)
105.27%
105.27%
105.27%
104.15%
104.15%
104.15%
104.10%
103.25%
102.48%
-500MW to Zone J at J EFORd
Base Case
+500MW to Zone J at J EFORd
Optimize w/o TSL Cost (million $)
Optimize w/ TSL Cost (million $)
Current LCR Cost (million $)
Optimize w/o TSL Zone K LCR
Optimize w/ TSL Zone K LCR (Limit @ 102.99%)
Current LCR Zone K LCR

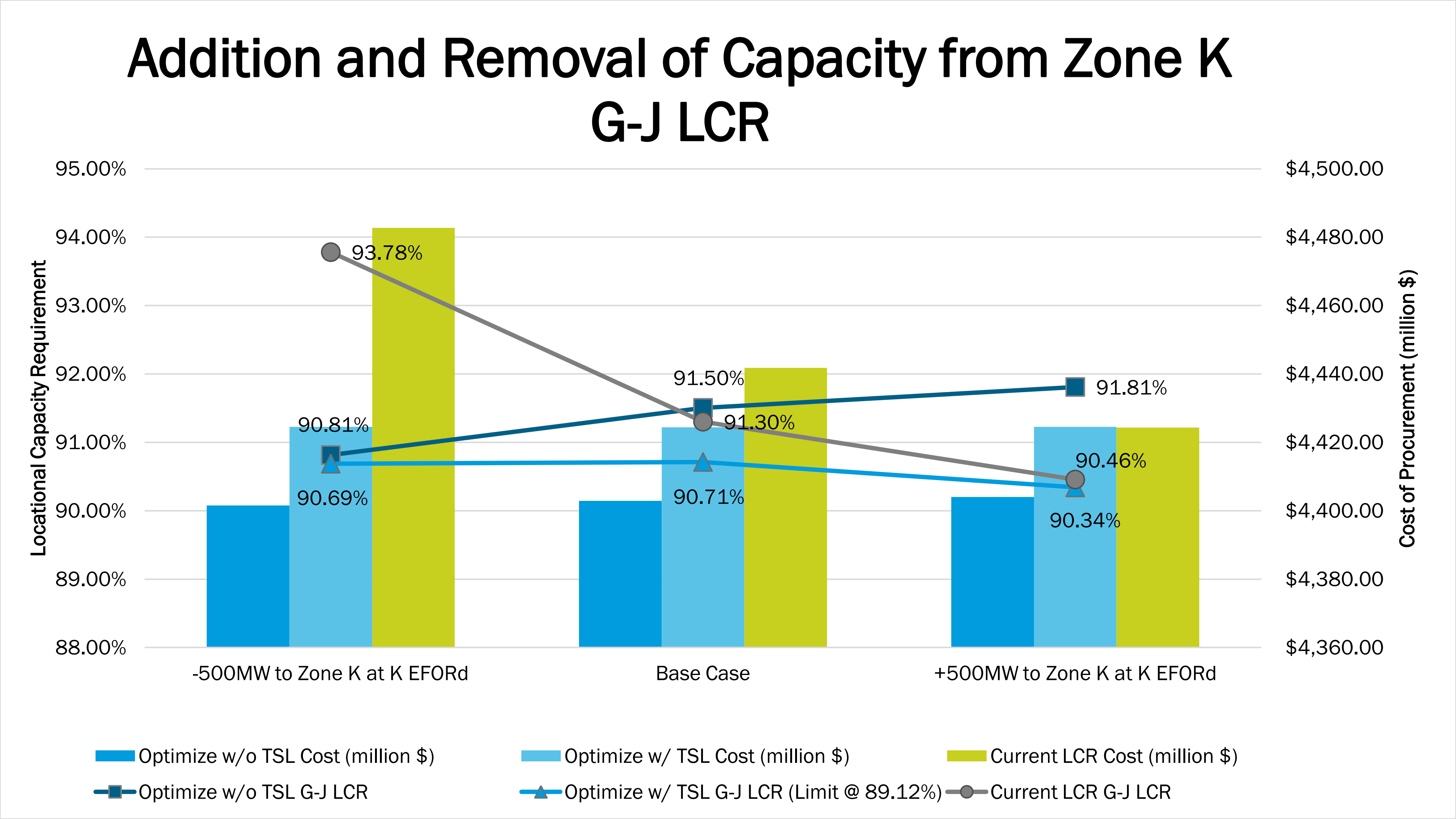

Addition and Removal of Capacity from Zone J
G-J LCR
Locational Capacity Requirement
Cost of Procurement (million $)
92.20%
92.00%
91.80%
91.60%
91.40%
91.20%
91.00%
90.80%
90.60%
90.40%
90.20%
90.00%
$4,460.00
$4,450.00
$4,440.00
$4,430.00
$4,420.00
$4,410.00
$4,400.00
$4,390.00
$4,380.00
$4,370.00
91.50%
91.50%
91.50%
91.94%
91.30%
90.73%
90.71%
90.71%
90.71%
-500MW to Zone J at J EFORd
Base Case
+500MW to Zone J at J EFORd
Optimize w/o TSL Cost (million $)
Optimize w/ TSL Cost (million $)
Current LCR Cost (million $)
Optimize w/o TSL G-J LCR
Optimize w/ TSL G-J LCR (Limit @ 89.12%)
Current LCR G-J LCR

Market Simulations: +/- 500 MW to Zone K


Addition and Removal of Capacity from Zone K
Zone J LCR
Locational Capacity Requirement
Cost of Procurement (million $)
86.00%
84.00%
82.00%
80.00%
78.00%
76.00%
74.00%
$4,500.00
$4,480.00
$4,460.00
$4,440.00
$4,420.00
$4,400.00
$4,380.00
$4,360.00
84.43%
81.37%
80.16%
80.16%
80.16%
80.14%
78.05%
78.04%
78.29%
-500MW to Zone K at K EFORd
Base Case
+500MW to Zone K at K EFORd
Optimize w/o TSL Cost (million $)
Optimize w/ TSL Cost (million $)
Current LCR Cost (million $)
Optimize w/o TSL Zone J LCR
Optimize w/ TSL Zone J LCR (Limit @ 80.16%)
Current LCR Zone J LCR

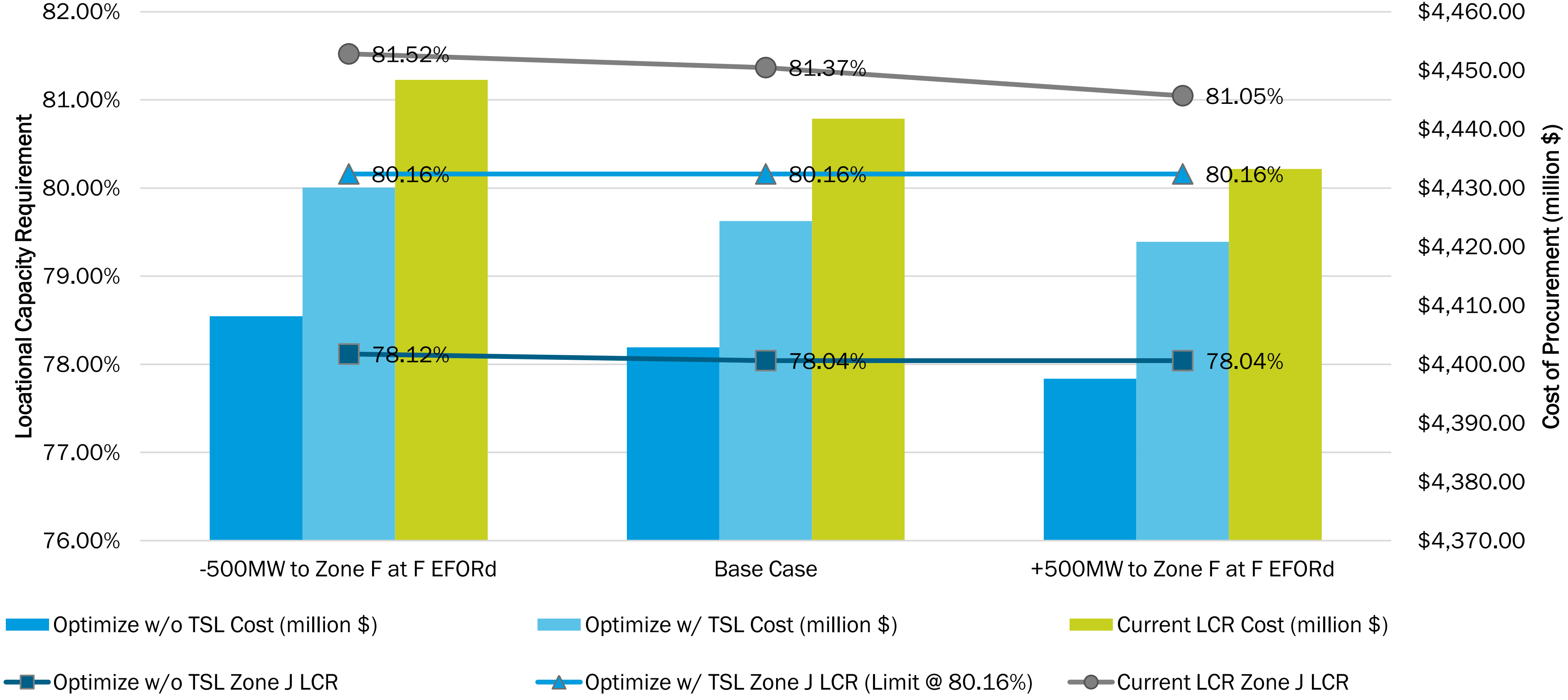
Addition and Removal of Capacity from Zone K
Zone K LCR

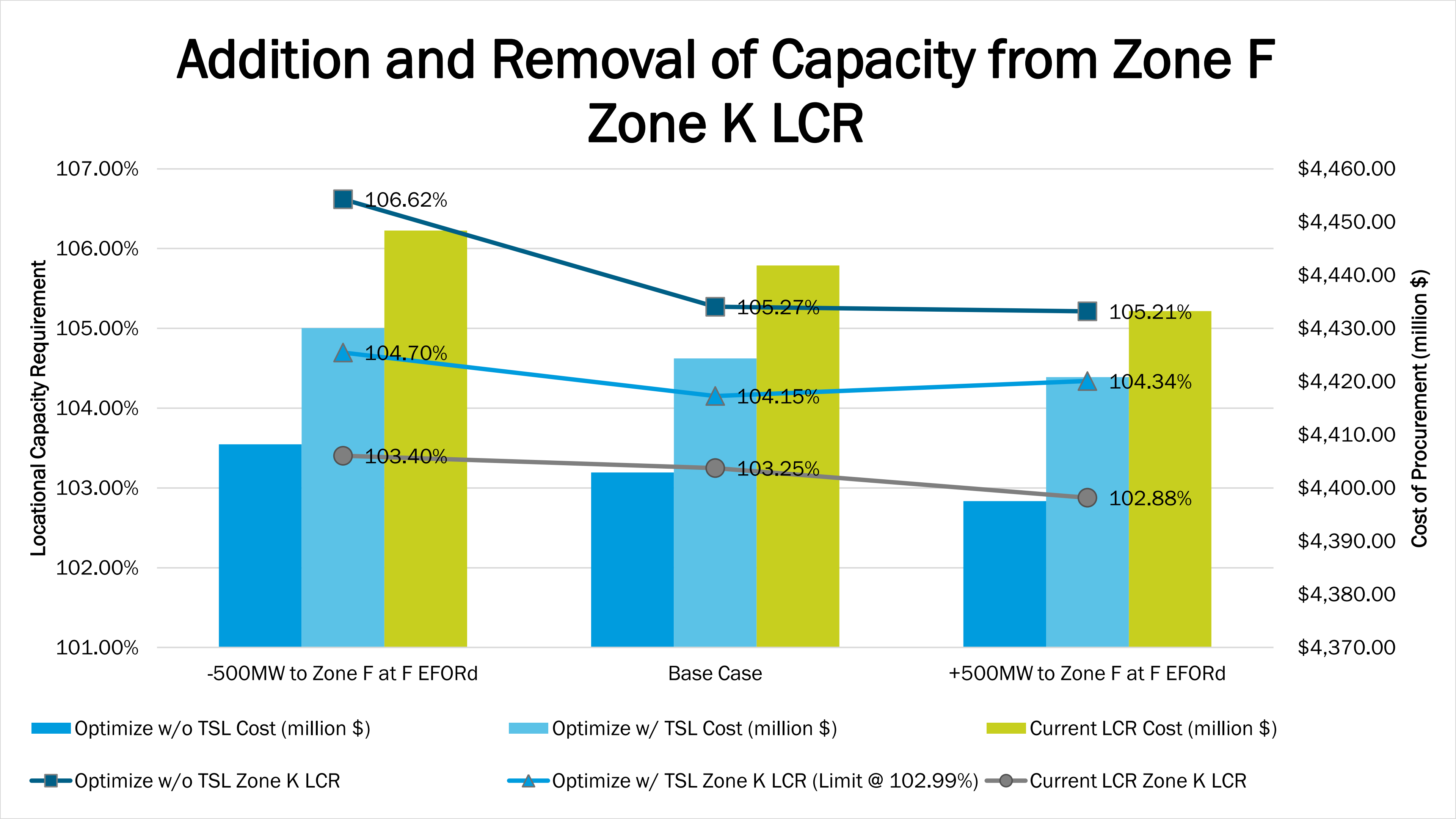


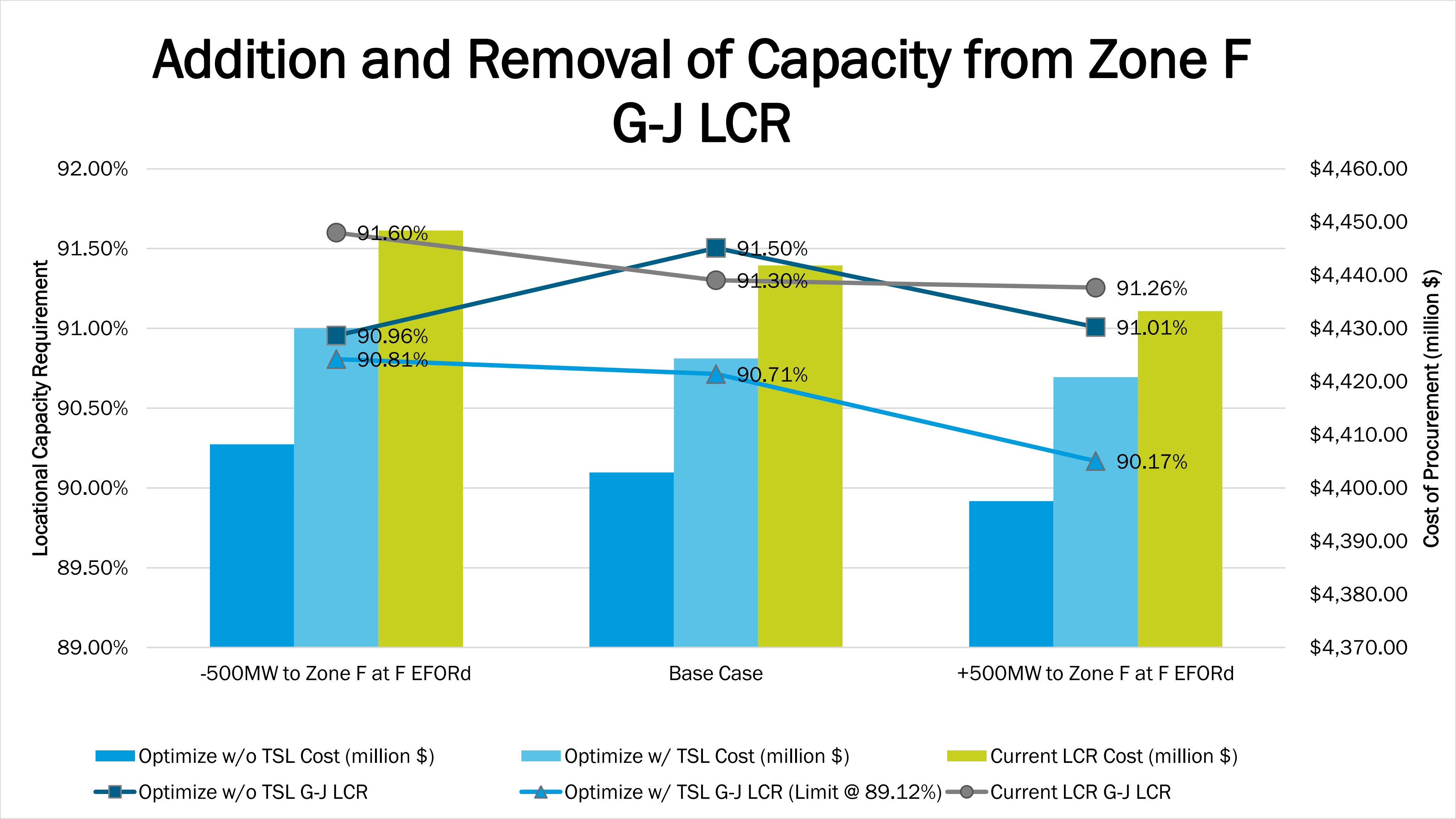

Addition and Removal of Capacity from Zone K G-J LCR
Locational Capacity Requirement
Cost of Procurement (million $)
95.00%
94.00%
93.00%
92.00%
91.00%
90.00%
89.00%
88.00%
$4,500.00
$4,480.00
$4,460.00
$4,440.00
$4,420.00
$4,400.00
$4,380.00
$4,360.00
93.78%
90.81%
90.69%
91.50%
91.30%
90.71%
91.81%
90.46%
90.34%
-500MW to Zone K at K EFORd
Base Case
+500MW to Zone K at K EFORd
Optimize w/o TSL Cost (million $)
Optimize w/ TSL Cost (million $)
Current LCR Cost (million $)
Optimize w/o TSL G-J LCR
Optimize w/ TSL G-J LCR (Limit @ 89.12%)
Current LCR G-J LCR

Market Simulations: +/- 500 MW to Zone F

Addition and Removal of Capacity from Zone F Zone J LCR




Addition and Removal of Capacity from Zone F
Zone K LCR
Locational Capacity Requirement
Cost of Procurement (million $)
107.00%
106.00%
105.00%
104.00%
103.00%
102.00%
101.00%
$4,460.00
$4,450.00
$4,440.00
$4,430.00
$4,420.00
$4,410.00
$4,400.00
$4,390.00
$4,380.00
$4,370.00
106.62%
105.27%
105.21%
104.70%
104.15%
104.34%
103.40%
103.25%
102.88%
-500MW to Zone F at F EFORd
Base Case
+500MW to Zone F at F EFORd
Optimize w/o TSL Cost (million $)
Optimize w/ TSL Cost (million $)
Current LCR Cost (million $)
Optimize w/o TSL Zone K LCR
Optimize w/ TSL Zone K LCR (Limit @ 102.99%)
Current LCR Zone K LCR


Addition and Removal of Capacity from Zone F G-J LCR
92.00%
91.50%
91.00%
90.50%
90.00%
89.50%
89.00%
Locational Capacity Requirement
$4,460.00
$4,450.00
$4,440.00
$4,430.00
$4,420.00
$4,410.00
$4,400.00
$4,390.00
$4,380.00
$4,370.00
Cost of Procurement (million $)
91.60%
91.50%
91.30%
91.26%
90.96%
91.01%
90.81%
90.71%
90.17%
-500MW to Zone F at F EFORd
Base Case
+500MW to Zone F at F EFORd
Optimize w/o TSL Cost (million $)
Optimize w/ TSL Cost (million $)
Current LCR Cost (million $)
Optimize w/o TSL G-J LCR
Optimize w/ TSL G-J LCR (Limit @ 89.12%)
Current LCR G-J LCR

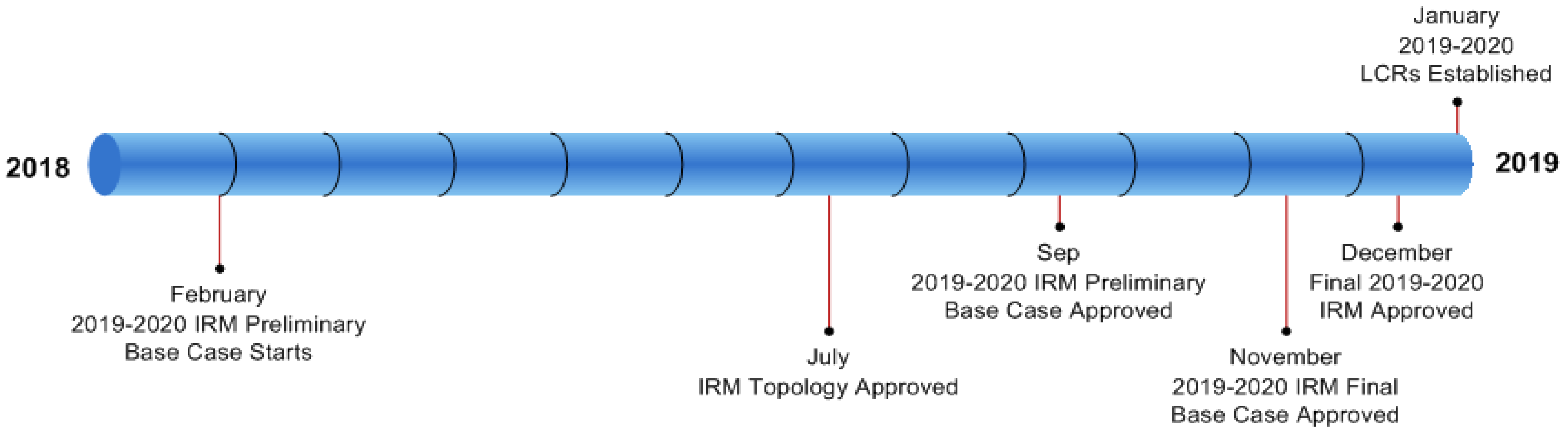
Initial Market Simulation Results

- The optimization methodology is more stable than the current LCR methodology
- The optimization methodology results in a lower cost than the current LCR methodology both with and without transmission security floors

NEW YORK INDEPENDENT SYSTEM OPERATOR

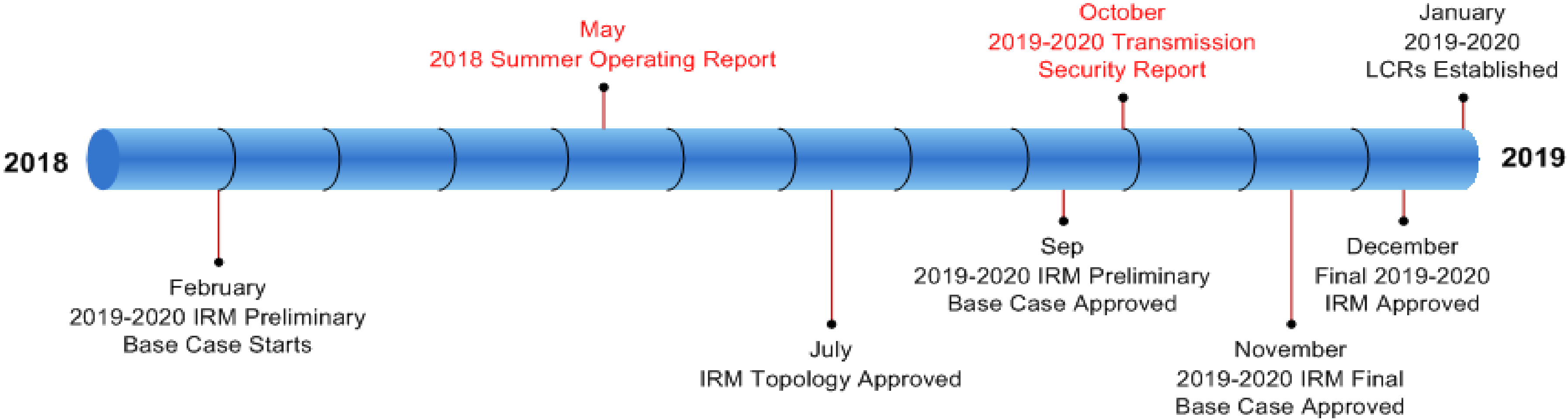
Phase 4: Defining Process

Current Timeline



DRAFT – FOR DISCUSSION PURPOSES ONLY

Timeline Additions



LCR Setting Timeline

- No alterations to the current timeline are needed to accommodate the alternative methodology for determining LCRs
- Transmission security analysis used in the alternative methodology would be conducted and reported prior to October 1st
  - This analysis would utilize an updated base case used in the Summer Operating Report

NEW YORK INDEPENDENT SYSTEM OPERATOR

Next Steps

Other Next Steps

- The NYISO will consider input received during today's ICAP Working Group meeting
- Additional comments sent to deckels@nyiso.com will be considered
- The NYISO will return to a future ICAPWG meeting to discuss its progress and adjustments to the plan after considering comments and results

2017 Project Development

Phase	Objective	Specific Topics:
Proof of Concept	Demonstrate alternative methodology in relation to guiding principles (*i.e.*, least cost, stability, robust, predictability)	Generation +/- Unit net CONE +/- Transmission +/-
Refine Methodology	Modify the alternative method to ensure that all aspects have a purpose and are being performed as a result of sound market and engineering principles	Unit net CONE curves Potential Bounds Modeling methodology
Market Simulations	Simulate market situations to demonstrate performance of methodology	Changes in resources Topological changes Locality configurations
Defining Process	Develop a process for the methodology that ensures guiding principles are being achieved over time	Develop process of method Process timeline Transition methods
Demonstrating Market Benefits	Demonstrate the methodology results in market benefits and resolve any issues that arise from its implementation	Consumer impact Multiyear simulation Cost allocation
Final Market Design	Summarize all findings and develop a final market design for implementation	Develop final market design

NEW YORK INDEPENDENT SYSTEM OPERATOR

Questions?

The Mission of the New York Independent System Operator, in collaboration with its stakeholders, is to serve the public interest and provide benefits to consumers by:

- Maintaining and enhancing regional reliability
- Operating open, fair and competitive wholesale electricity markets
- Planning the power system for the future
- Providing factual information to policy makers, stakeholders and investors in the power system

www.nyiso.com

NEW YORK INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY

Appendix

Scenario	Optimized LCR without Transmission Security Floors (%)			Optimized Cost (million)
	Zone J	Zone K	G-J	
Base Case	78.04%	105.27%	91.50%	$ 4,402.89
+500 MW to Zone G at G-J EFORd	78.11%	105.97%	90.76%	$ 4,401.96
-500 MW to Zone G at G-J EFORd	78.06%	105.93%	90.78%	$ 4,400.95
+500MW to Zone J at J EFORd	78.04%	105.27%	91.50%	$ 4,402.89
-500MW to Zone J at J EFORd	78.04%	105.27%	91.50%	$ 4,402.89
+500MW to Zone K at K EFORd	78.29%	104.55%	91.81%	$ 4,404.03
-500MW to Zone K at K EFORd	78.05%	105.99%	90.81%	$ 4,401.55
+500MW to Zone F at F EFORd	78.04%	105.21%	91.01%	$ 4,397.54
-500MW to Zone F at F EFORd	78.12%	106.62%	90.96%	$ 4,408.19

Scenario	Optimized LCR with Transmission Security Floors (%)			Optimized Cost (million)
	Zone J	Zone K	G-J	
Base Case	80.16%	104.15%	90.71%	$4,424.37
+500 MW to Zone G at G-J EFORd	80.16%	104.56%	90.27%	$4,423.79
-500 MW to Zone G at G-J EFORd	80.16%	104.52%	90.40%	$4,424.65
+500MW to Zone J at J EFORd	80.16%	104.15%	90.71%	$4,424.37
-500MW to Zone J at J EFORd	80.16%	104.15%	90.71%	$4,424.37
+500MW to Zone K at K EFORd	80.16%	104.57%	90.34%	$4,424.52
-500MW to Zone K at K EFORd	80.16%	104.20%	90.69%	$4,424.55
+500MW to Zone F at F EFORd	80.16%	104.34%	90.17%	$4,420.83
-500MW to Zone F at F EFORd	80.16%	104.70%	90.81%	$4,430.07

Scenario	Current LCR Methodology (%)			Optimized Cost (million)
	Zone J	Zone K	G-J	
Base Case	81.4%	103.2%	91.3%	$ 4,441.80
+500 MW to Zone G at G-J EFORd	79.87%	102.37%	93.44%	$ 4,429.79
-500 MW to Zone G at G-J EFORd	83.52%	104.21%	89.86%	$ 4,470.71
+500MW to Zone J at J EFORd	81.94%	102.48%	91.94%	$ 4,450.11
-500MW to Zone J at J EFORd	80.38%	104.10%	90.73%	$ 4,428.17
+500MW to Zone K at K EFORd	80.14%	104.48%	90.46%	$ 4,424.31
-500MW to Zone K at K EFORd	84.43%	100.67%	93.78%	$ 4,482.72
+500MW to Zone F at F EFORd	81.05%	102.88%	91.26%	$ 4,433.26
-500MW to Zone F at F EFORd	81.52%	103.40%	91.60%	$ 4,448.38

Exhibit 26

Consumer Impact Analysis: Alternative Methods for Determining LCRs

Tariq N. Niazi
Senior Manager, Consumer Interest Liaison

Installed Capacity Working Group

October 11, 2017

DRAFT – FOR DISCUSSION PURPOSES ONLY

Agenda

- Project Objective
- Background
- Cost Impacts
- Additional Factors
- Other Impacts
- Feedback
- Next Steps

Project Objective for Determining Alternative LCRs

- Evaluate an alternative methodology for determining LCRs based on economic optimization that minimizes the cost of satisfying planning requirements
  - Identify LCRs that provide the least cost distribution of capacity resources amongst NYCA Localities while keeping LOLE<0.1

Background

- The NYISO started this project by first establishing guiding principles (least cost, stable, robust, predictable)
- Next, the proof of concept phase demonstrated how the alternative LCR methodology performs in relation to the guiding principles
- This was followed by Phase 2, which focused on refining the methodology to ensure that optimization is based on sound market and engineering principles
- Phase 3 will focus on simulating market situations to demonstrate the performance of the alternative methodology

NEW YORK INDEPENDENT SYSTEM OPERATOR

Consumer Impact Analysis (IA) Evaluation Areas

- Present the potential impact on all four evaluation areas

RELIABILITY	COST IMPACT/ MARKET EFFICIENCIES
ENVIRONMENT/ NEW TECHNOLOGY	TRANSPARENCY

NEW YORK INDEPENDENT SYSTEM OPERATOR

Cost Impact Methodology

- The impact analysis compares the cost impacts on consumers in each of the three Localities (J, K, G-J) and NYCA of the alternative LCR methodology with the current methodology for the, short term, intermediate, and long term
- The base case and the sensitivity cases referenced herein are the same as those presented to stakeholders
  - The cost impact analysis utilizes the results produced after all refinements were incorporated into the methodology (*i.e.*, final methodology)
- The 2017/2018 Capability Year LCR base case was solved to an LOLE of 0.1 days/year while using the NYCA Minimum Installed Capacity Requirement

NEW YORK INDEPENDENT SYSTEM OPERATOR

Consumer Impact Assumptions

- **Load**
  - Equivalent to the peak load in the MARS case
- **Reference Point**
  - Current values, except when sensitivity assumed a change in Net CONE
- **Derating Factor**
  - Historical values
- **Supply**
  - **Short Term:** Current generation with assumed values for imports, exports, unsold, and unoffered based on historical levels
  - **Intermediate Term:** Same as short term except with the removal or addition of the generation assumed in the sensitivity
  - **Level of Excess:** Supply level is equal to the LCR/IRM plus the assumed level of excess defined in the Demand Curve Reset
  - **Historical Percentage Excess:** Supply level is equal to the historic excess defined as a percentage of excess above the requirement observed within the last 3 Capability Years in each of the different Localities

NEW YORK INDEPENDENT SYSTEM OPERATOR

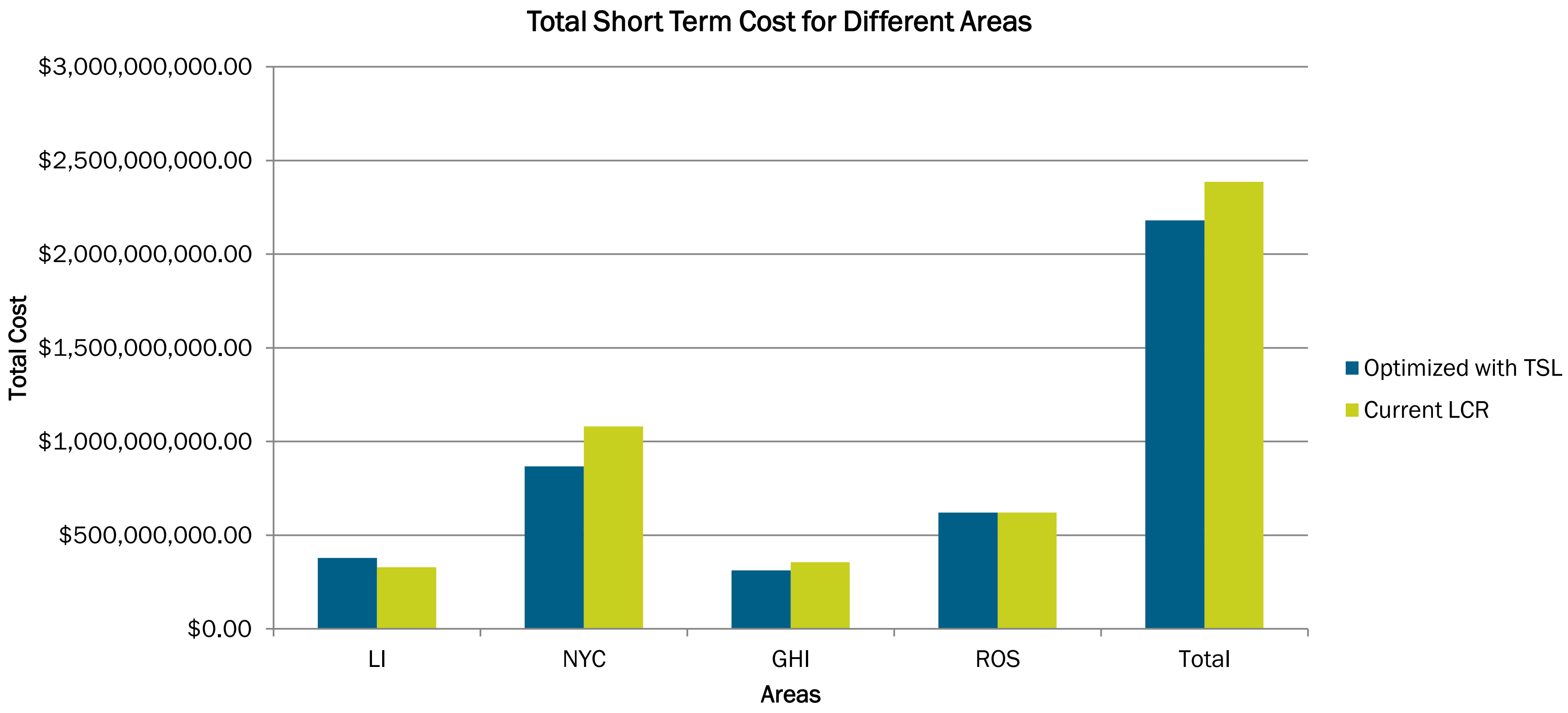
Consumer Costs in the Short & Intermediate Term

Short Term Cost Impact Methodology

- The short term impact compares the cost of applying the current methodology and the alternative methodology to the 2017/2018 Capability Year LCR base case
  - The short-run impact analysis assumes no changes to generation and transmission

Scenario	Optimized Costs ($)			Current LCR Methodology Costs ($)		
	As found	At Level of Excess	At Generic excess level	As found	At Level of Excess	At Generic excess level
Base Case						
+500 MW in G						
-500 MW in G						

Difference in cost is short run impact (as found system and assumes no changes)



TSL = Transmission Security Limits

Intermediate Cost Impact Methodology

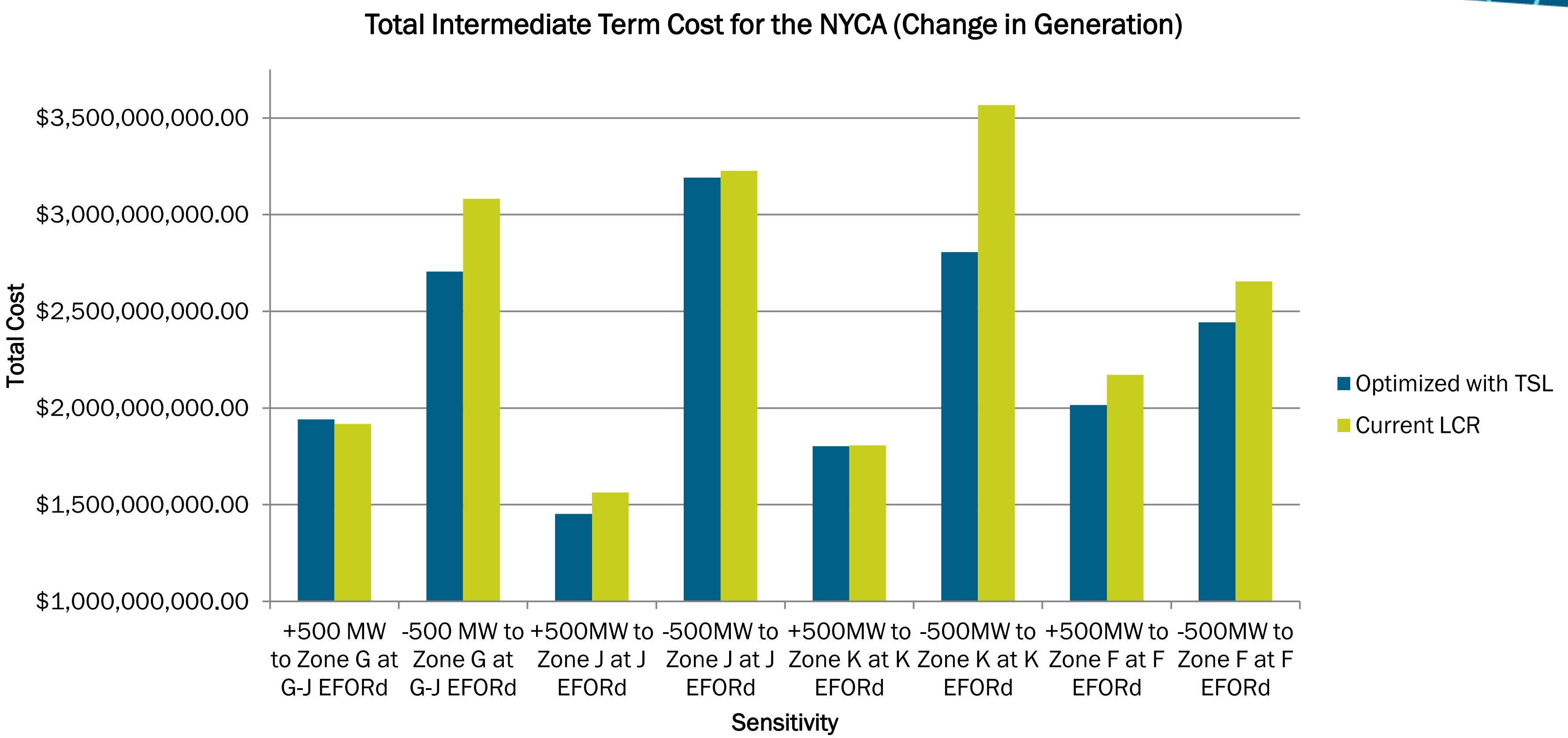
- The intermediate impact compares the cost of applying the current LCR methodology with the alternative methodology as generation and transmission resources change
  - This analysis assumes the only change to the system is the change used to perform the sensitivity case
  - For example, the cost impact of a +500 MW Zone J sensitivity case would keep all assumptions constant except for the addition of 500 MW to Zone J
- The intermediate impact was performed on a sub-set of simple sensitivity cases along with a set of sensitivities that include multiple changes to the system
- Sensitivities were also performed for changes in net CONE

NEW YORK INDEPENDENT SYSTEM OPERATOR

Scenario	Optimized Costs ($)			Current LCR Methodology Costs ($)		
	As found	At Level of Excess	At Generic excess level	As found	At Level of Excess	At Generic excess level
Base Case						
+500 MW in G						
- 500 MW in G						

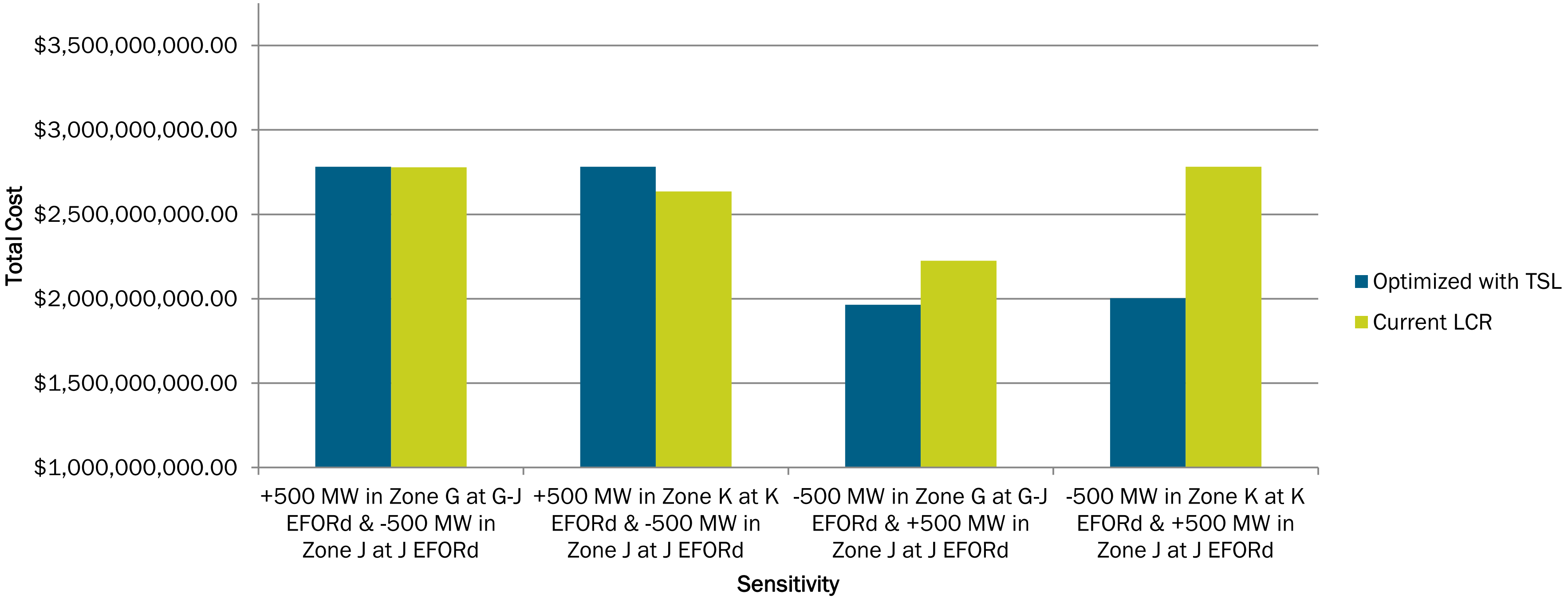
Difference in cost is intermediate impact (as found system with an addition and subtraction of 500 MW to G)

NEW YORK INDEPENDENT SYSTEM OPERATOR



NEW YORK INDEPENDENT SYSTEM OPERATOR

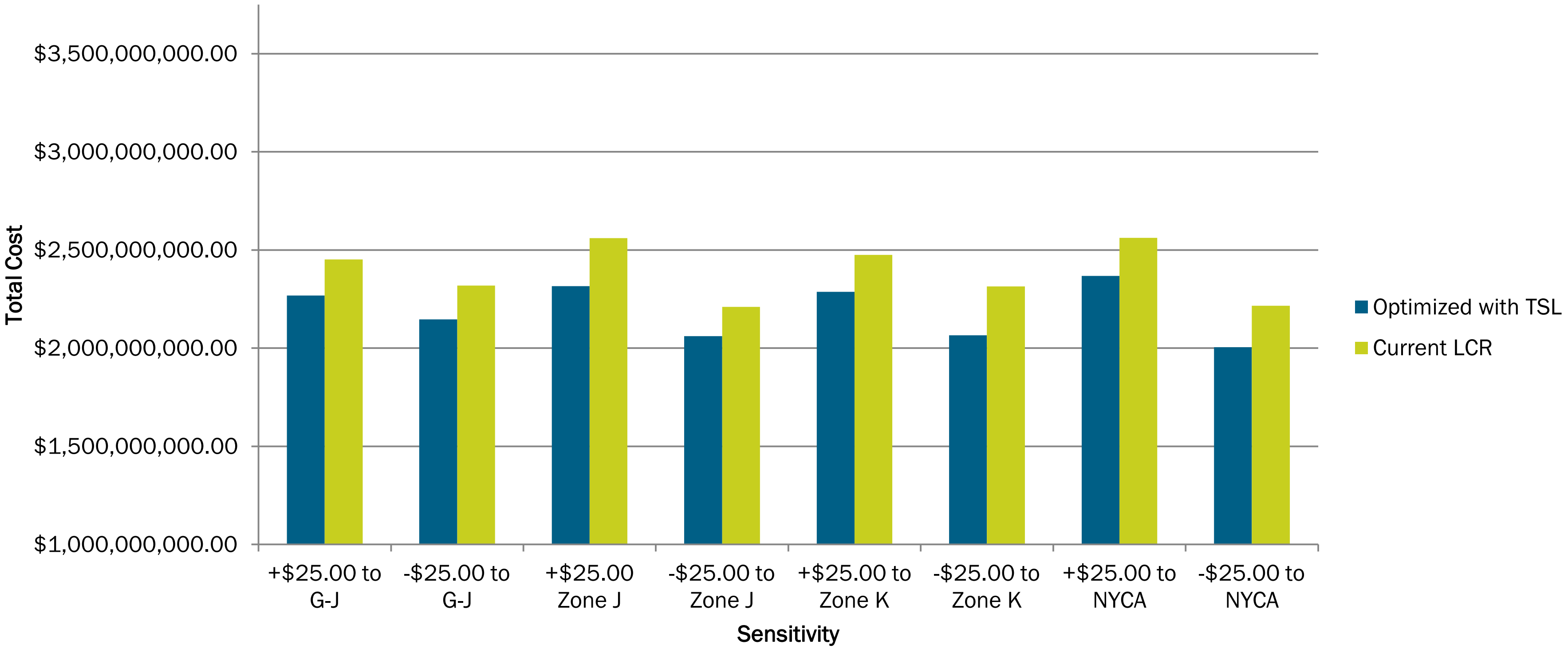
Total Intermediate Term Cost for NYCA (Multiple Changes in Generation)



NEW YORK INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY

Total Intermediate Term Cost for NYCA (Change in Net CONE)



NEW YORK INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY

Sensitivity	Δ Short & Intermediate Term Costs from Current LCR to Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
Base Case	$51.11	-$212.66	-$44.33	$0.00	-$205.88
+500 MW to Zone G at G-J EFORd	$125.27	$51.96	-$153.43	$0.00	$23.81
-500 MW to Zone G at G-J EFORd	$17.39	-$431.24	$36.33	$0.00	-$377.53
+500MW to Zone J at J EFORd	$95.83	-$163.15	-$42.96	$0.00	-$110.28
-500MW to Zone J at J EFORd	$2.84	-$35.90	-$1.17	$0.00	-$34.24
+500MW to Zone K at K EFORd	$0.00	$4.77	-$8.51	$0.00	-$3.74
-500MW to Zone K at K EFORd	$176.11	-$726.29	-$210.43	$0.00	-$760.61
+500MW to Zone F at F EFORd	$83.41	-$156.50	-$82.52	$0.00	-$155.62
-500MW to Zone F at F EFORd	$73.11	-$239.52	-$46.42	$0.00	-$212.83

Sensitivity	Δ Short & Intermediate Term Costs from Current LCR to Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
+1000 MW to UPNYSENY	$107.88	$142.14	-$110.75	$0.00	$139.28
+$25.00 to G-J	$155.10	-$212.66	-$126.83	$0.00	-$184.39
-$25.00 to G-J	-$15.26	-$212.66	$55.22	$0.00	-$172.69
+$25.00 Zone J	$74.53	-$246.68	-$73.12	$0.00	-$245.26
-$25.00 to Zone J	$51.11	-$155.60	-$44.33	$0.00	-$148.82
+$25.00 to Zone K	$10.29	-$212.66	$13.82	$0.00	-$188.54
-$25.00 to Zone K	$40.66	-$212.66	-$76.86	$0.00	-$248.85
+$25.00 to NYCA	$4.37	-$212.66	$14.68	$0.00	-$193.60
-$25.00 to NYCA	$74.17	-$212.66	-$71.94	$0.00	-$210.43
+500 MW in Zone G & -500 MW in Zone J	$79.84	$154.57	-$230.94	$0.00	$3.47
+500 MW in Zone K & -500 MW in Zone J	$0.00	$120.91	$25.27	$0.00	$146.17
-500 MW in Zone G & +500 MW in Zone J	$48.98	-$329.79	$20.31	$0.00	-$260.50
-500 MW in Zone K & +500 MW in Zone J	$194.48	-$776.11	-$197.59	$0.00	-$779.23

	Δ Short & Intermediate Term Costs from Current LCR to Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
Minimum	-$15.26	-$776.11	-$230.94	$0.00	-$779.23
25th percentile	$12.07	-$232.80	-$103.69	$0.00	-$237.15
Average	$65.96	-$194.32	-$61.66	$0.00	-$190.01
75th percentile	$92.72	-$65.82	$10.07	$0.00	-$53.25
Maximum	$194.48	$154.57	$55.22	$0.00	$146.17

Short & Intermediate Term Consumer Impacts

- **Based on the sensitivities conducted, total NYCA consumer cost is reduced in the majority of cases**
  - The only cases that do not result in savings occur when the current LCR methodology results in a Zone J LCR lower than the Transmission Security Floor used in the optimization
- **The average benefit from the Optimized LCR methodology with TSL compared to the Current LCR methodology is approximately $190 million**

Consumer Costs at Level of Excess (LOE)

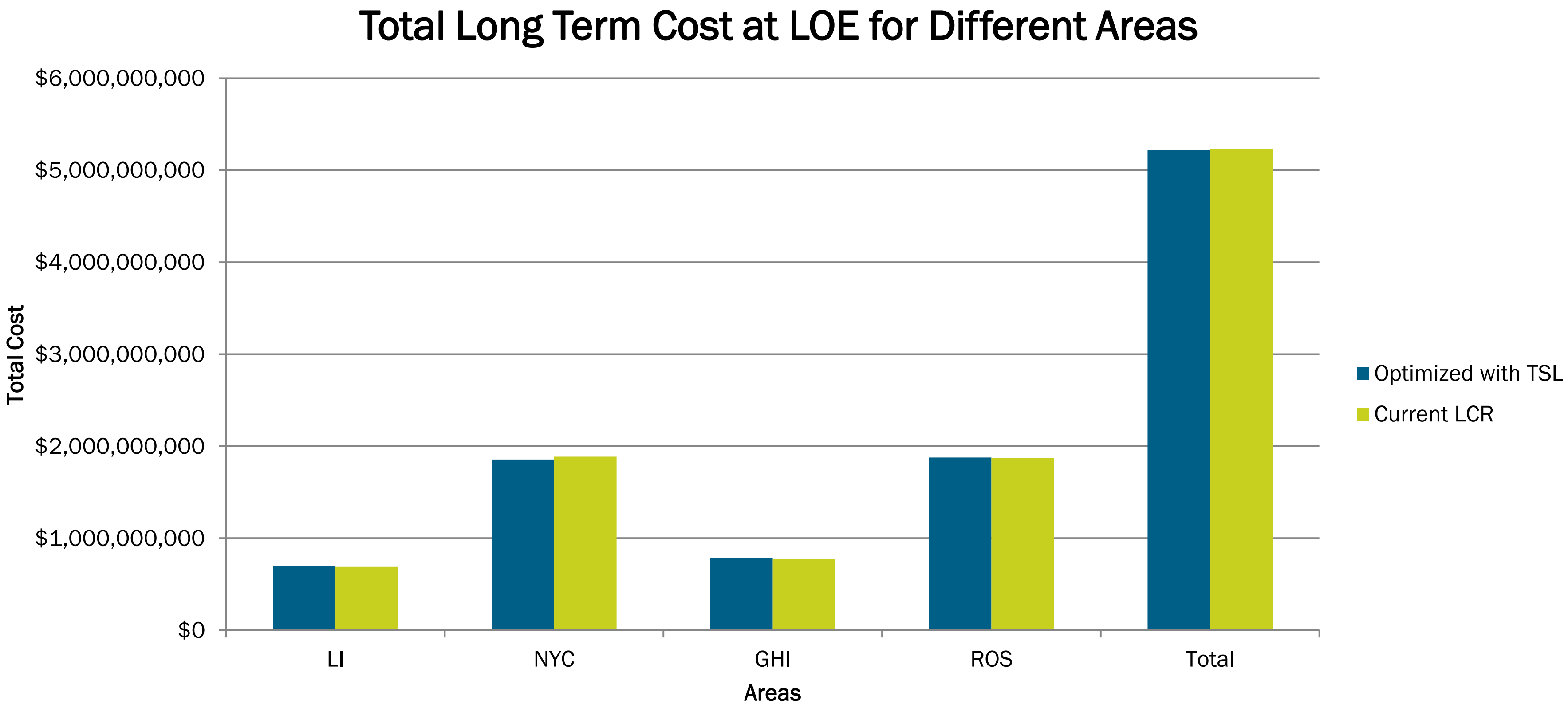
Long Term Cost Impact Methodology

- **The long term cost impact compares the cost of the current LCR methodology with the alternative methodology at long-run equilibrium**
  - The long-run equilibrium was modeled at the Level of Excess condition (Defined in the Demand Curve reset), and also
  - Historic excess defined as a percentage of excess above the requirement observed within the last 3 Capability Years in each of the different Localities

NEW YORK INDEPENDENT SYSTEM OPERATOR

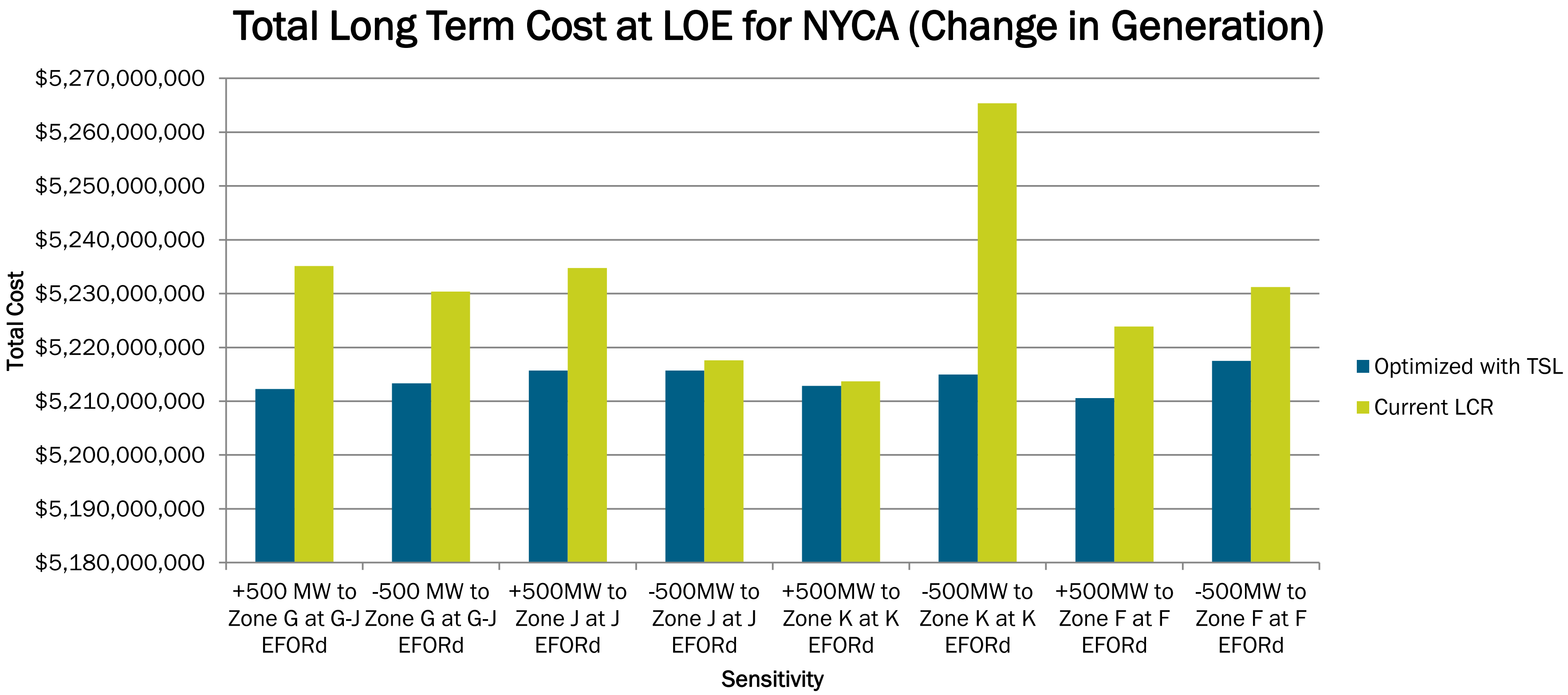
Scenario	Optimized Costs ($)			Current LCR Methodology Costs ($)		
	As found	At Level of Excess	At Generic excess level	As found	At Level of Excess	At Generic excess level
Base Case						
+500 MW in G						
-500 MW in G						

Difference in cost is long term impact (at LOE)



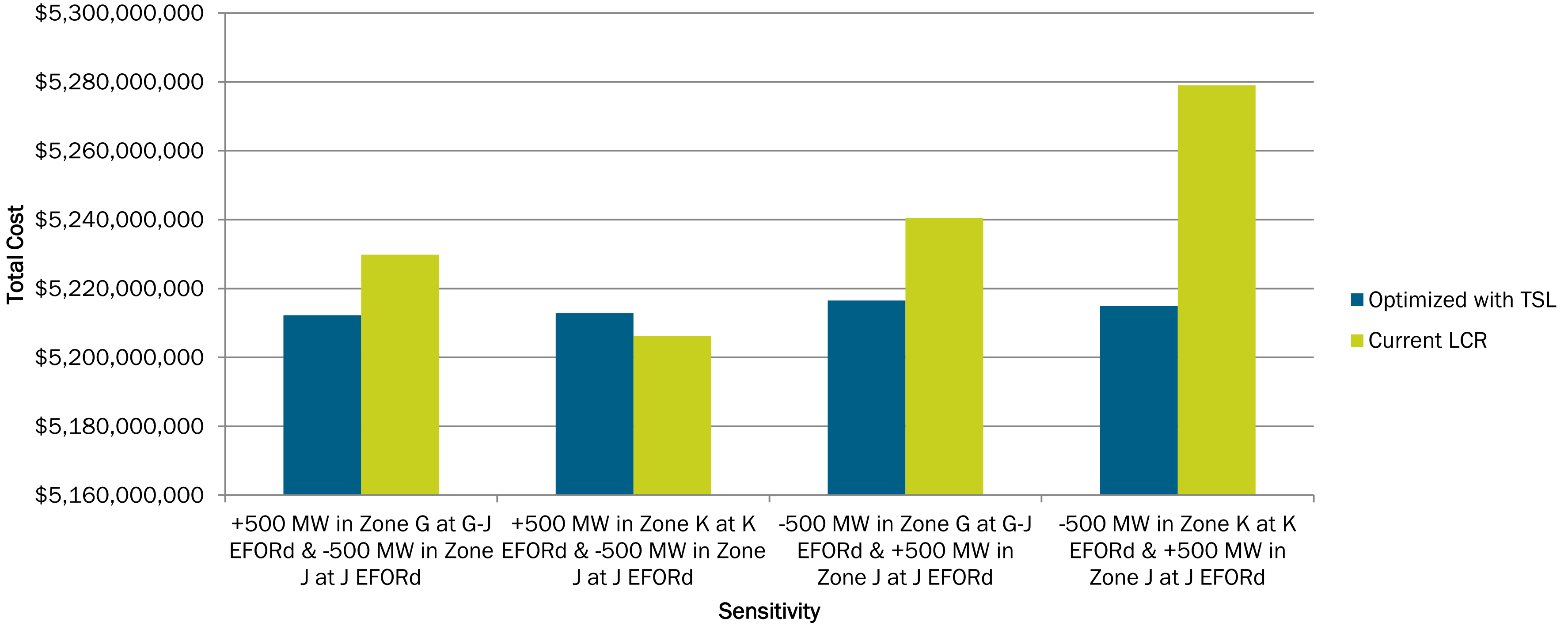
NEW YORK INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY

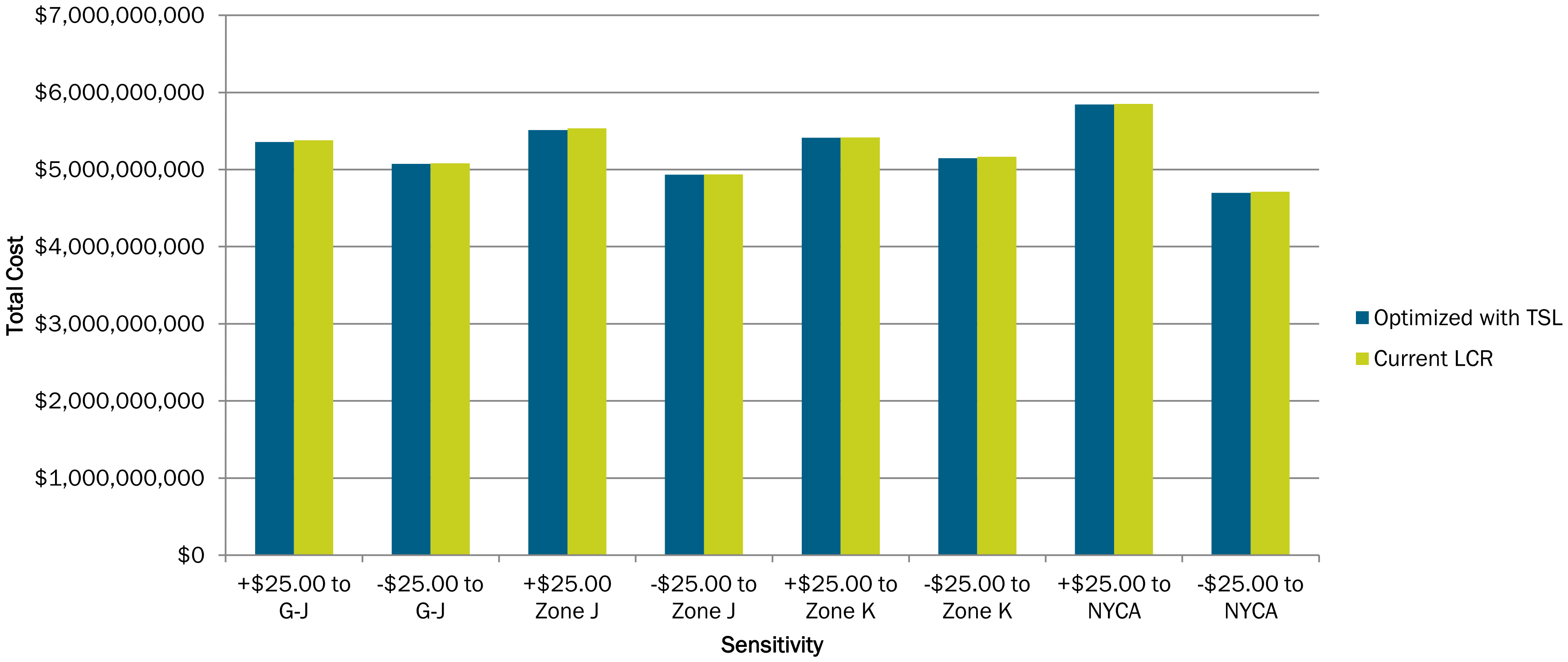


DRAFT – FOR DISCUSSION PURPOSES ONLY

Total Long Term Cost at LOE for NYCA (Multiple Changes in Generation)



Total Long Term Cost at LOE for NYCA (Change in Net CONE)



DRAFT – FOR DISCUSSION PURPOSES ONLY

Sensitivity	Δ Cost at LOE from Current LCR to Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
Base Case	$7.80	-$31.74	$7.56	$4.70	-$11.68
+500 MW to Zone G at G-J EFORd	$18.04	$7.60	-$89.40	$40.91	-$22.85
-500 MW to Zone G at G-J EFORd	$2.65	-$87.49	$78.69	-$10.92	-$17.06
+500MW to Zone J at J EFORd	$14.05	-$45.76	$1.64	$11.01	-$19.06
-500MW to Zone J at J EFORd	$0.36	-$6.07	$3.85	-$0.09	-$1.94
+500MW to Zone K at K EFORd	$0.60	$0.57	-$3.40	$1.39	-$0.84
-500MW to Zone K at K EFORd	$29.82	-$111.71	-$0.43	$31.91	-$50.42
+500MW to Zone F at F EFORd	$12.04	-$23.40	-$11.86	$9.91	-$13.31
-500MW to Zone F at F EFORd	$10.33	-$35.26	$5.28	$5.89	-$13.75

Sensitivity	Δ Cost at LOE from Current LCR to Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
+1000 MW to UPNYSENY	$15.88	$21.00	-$153.53	$77.85	-$38.80
+$25.00 to G-J	$23.24	-$31.87	-$30.80	$15.18	-$24.26
-$25.00 to G-J	-$2.33	-$31.74	$38.48	-$14.01	-$9.60
+$25.00 Zone J	$11.17	-$36.17	-$2.65	$8.66	-$18.98
-$25.00 to Zone J	$7.80	-$24.26	$7.56	$4.70	-$4.20
+$25.00 to Zone K	$1.15	-$31.74	$27.86	-$3.94	-$6.67
-$25.00 to Zone K	$8.50	-$31.74	-$4.64	$9.22	-$18.66
+$25.00 to NYCA	$1.08	-$31.74	$28.20	-$5.34	-$7.80
-$25.00 to NYCA	$11.09	-$31.74	-$2.32	$6.18	-$16.79
+500 MW in Zone G & -500 MW in Zone J	$11.71	$24.44	-$94.00	$40.27	-$17.58
+500 MW in Zone K & -500 MW in Zone J	-$8.89	$19.91	-$4.83	$0.43	$6.61
-500 MW in Zone G & +500 MW in Zone J	$7.48	-$110.46	$89.00	-$10.00	-$23.98

	Δ Cost at LOE from Current LCR to Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
Minimum	-$8.89	-$138.07	-$153.53	-$14.01	-$64.04
25th percentile	$1.53	-$35.94	-$4.79	$0.04	-$21.90
Average	$9.83	-$34.88	-$5.07	$12.14	-$17.98
75th percentile	$13.55	-$10.40	$7.56	$14.14	-$8.25
Maximum	$32.71	$24.44	$89.00	$77.85	$6.61

NEW YORK INDEPENDENT SYSTEM OPERATOR

Long Term Consumer Impacts at Level of Excess

- **Based on the sensitivities conducted, total long term NYCA consumer cost at the LOE is reduced in all cases, except one**
  - The only case that did not result in savings occurs when the current LCR methodology results in a Zone J LCR lower than the Transmission Security Floor used in the optimization
- **Consumer savings in the long term are smaller than the short term savings since the difference in the quantity of capacity purchased for each Locality is minimal between the current LCR methodology and the optimization while the price stays relatively stable**

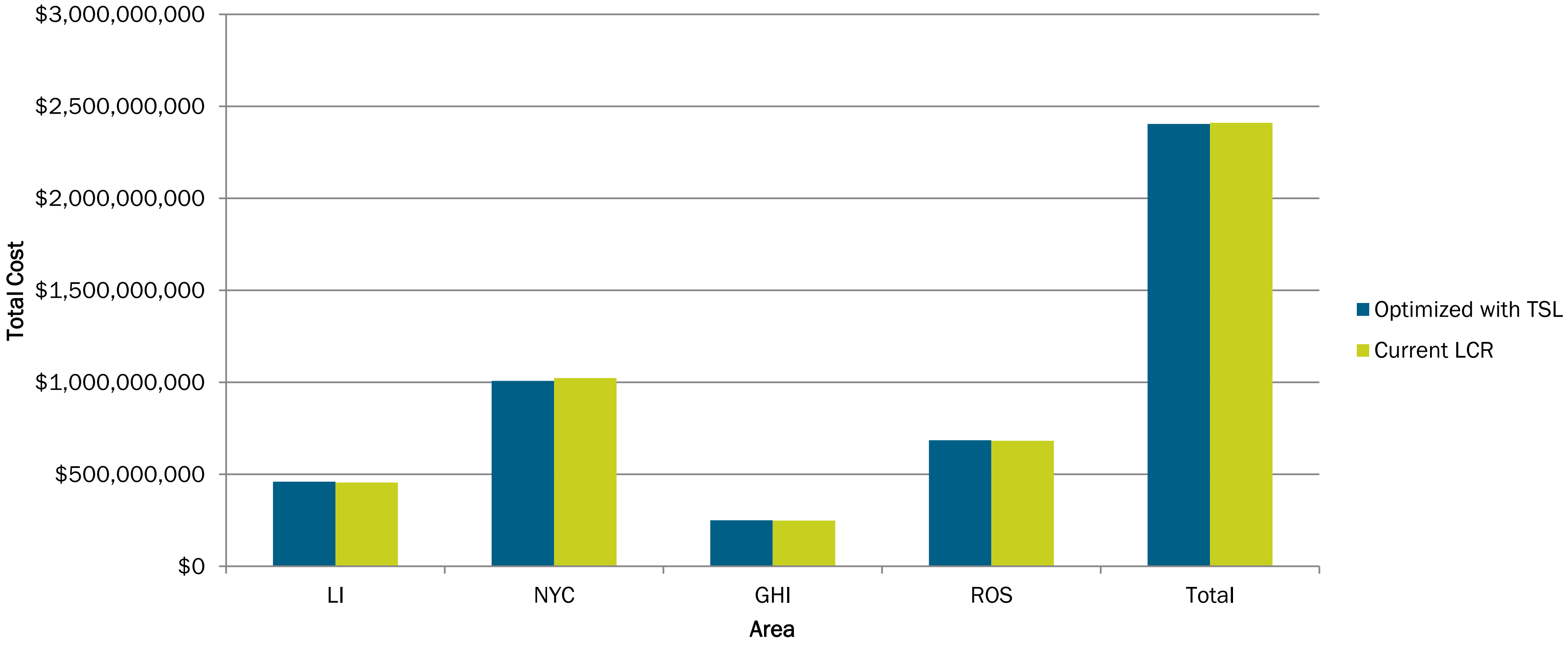
NEW YORK INDEPENDENT SYSTEM OPERATOR

Consumer Costs at Historic Percentage Excess

Scenario	Optimized Costs ($)			Current LCR Methodology Costs ($)		
	As found	At Level of Excess	At Generic excess level	As found	At Level of Excess	At Generic excess level
Base Case						
+500 MW in G						
-500 MW in G						

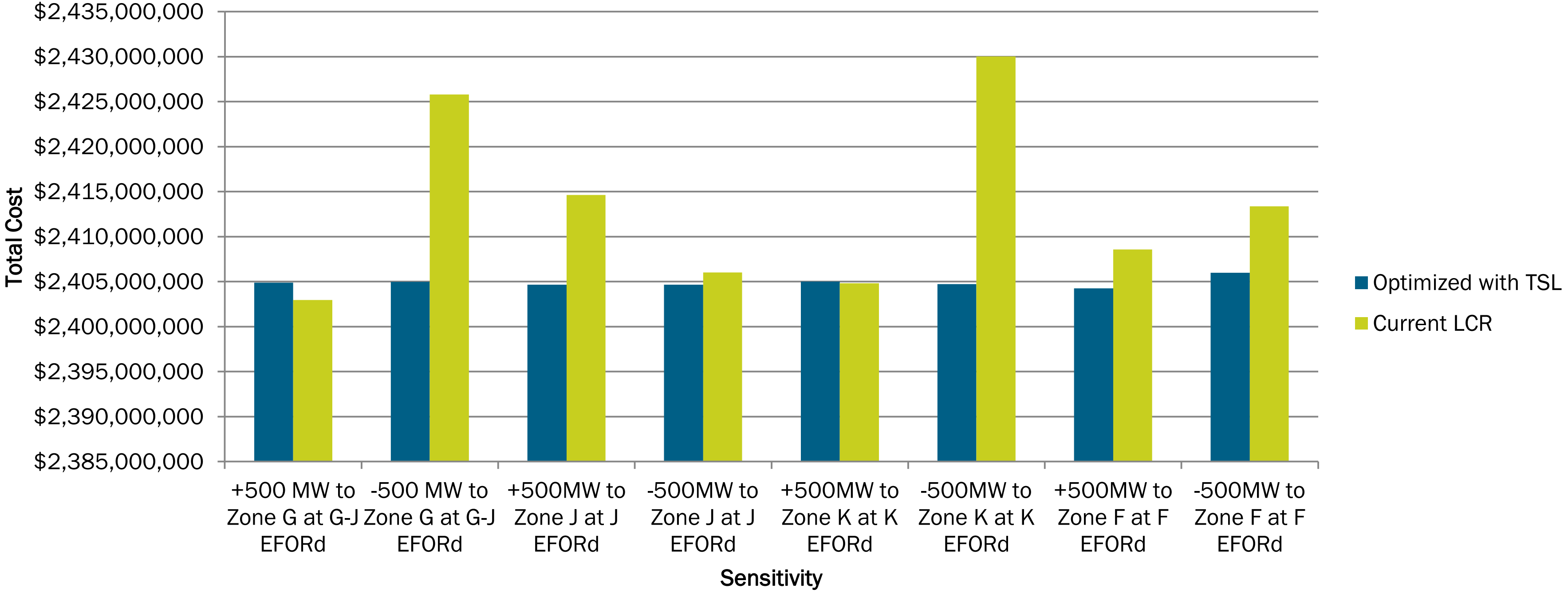
Difference in cost is long term impact (at generic excess)

Total Long Term Cost at Historic Excess for Different Areas



DRAFT – FOR DISCUSSION PURPOSES ONLY

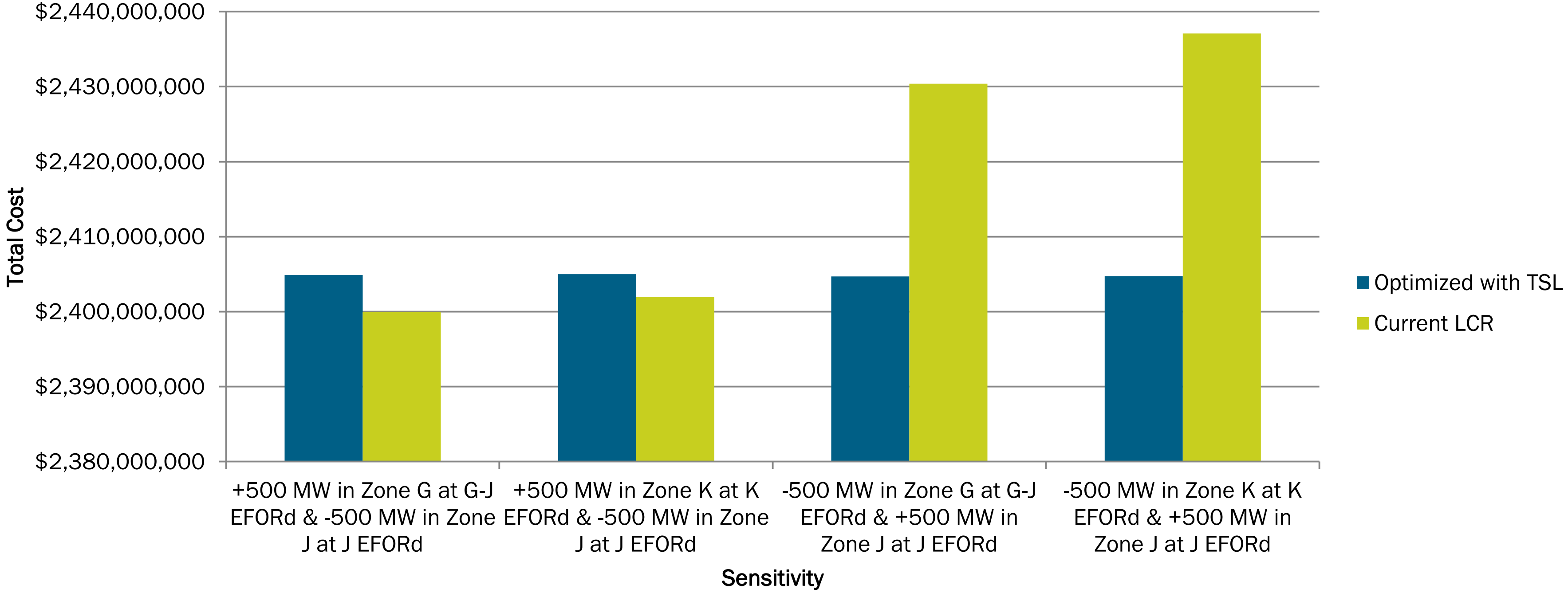
Total Long Term Cost at Historic Percentage Excess Level for NYCA (Change in Generation)



NEW YORK INDEPENDENT SYSTEM OPERATOR

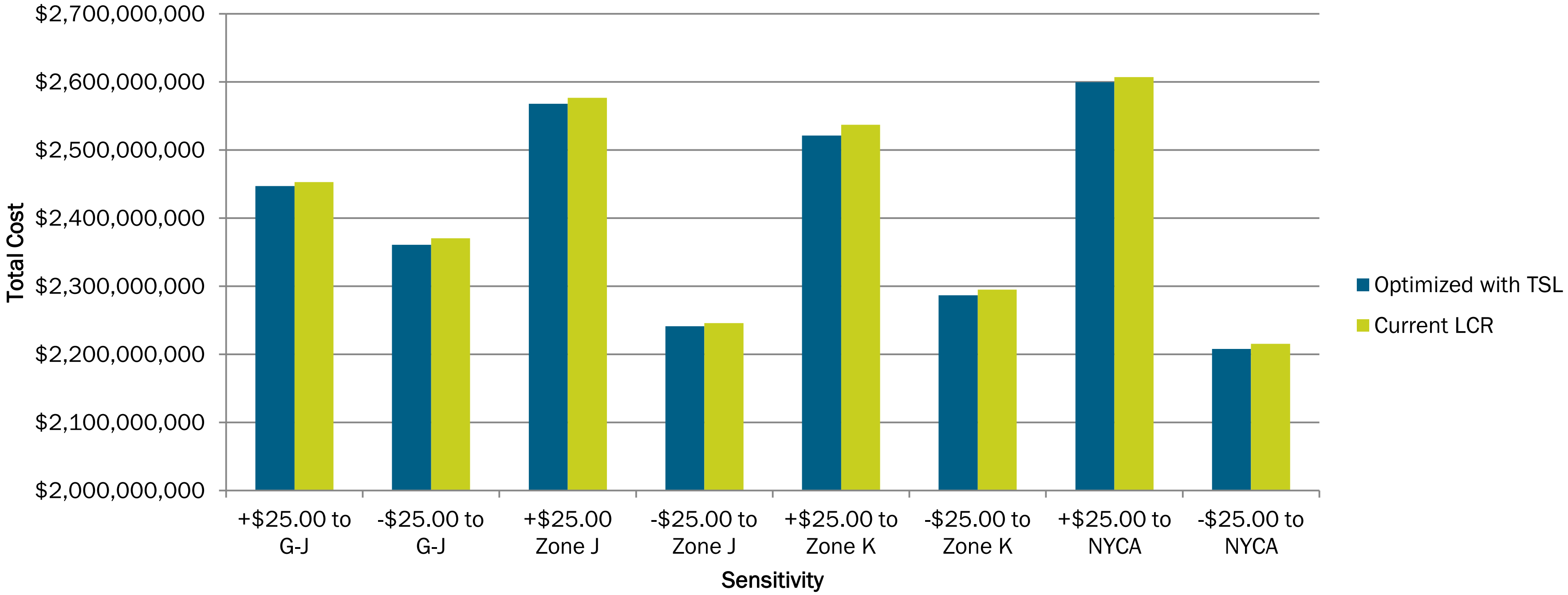
DRAFT – FOR DISCUSSION PURPOSES ONLY

Total Long Term Cost at Historic Percentage Excess Level for NYCA (Multiple Changes in Generation)



DRAFT – FOR DISCUSSION PURPOSES ONLY

Total Long Term Cost at Historic Percentage Excess Level for NYCA (Change in Net CONE)



NEW YORK INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY

Sensitivity	Δ Cost at Historic Excess from Current LCR to Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
Base Case	$3.99	-$15.16	$2.45	$1.81	-$6.91
+500 MW to Zone G at G-J EFORd	$9.68	$3.62	-$27.06	$15.70	$1.93
-500 MW to Zone G at G-J EFORd	$1.36	-$42.27	$24.27	-$4.17	-$20.82
+500MW to Zone J at J EFORd	$7.39	-$22.32	$0.73	$4.24	-$9.96
-500MW to Zone J at J EFORd	$0.25	-$2.76	$1.19	-$0.03	-$1.35
+500MW to Zone K at K EFORd	$0.41	$0.32	-$1.06	$0.53	$0.20
-500MW to Zone K at K EFORd	$15.60	-$53.74	$0.58	$12.27	-$25.29
+500MW to Zone F at F EFORd	$6.46	-$11.15	-$3.44	$3.82	-$4.32
-500MW to Zone F at F EFORd	$5.73	-$17.11	$1.73	$2.28	-$7.38

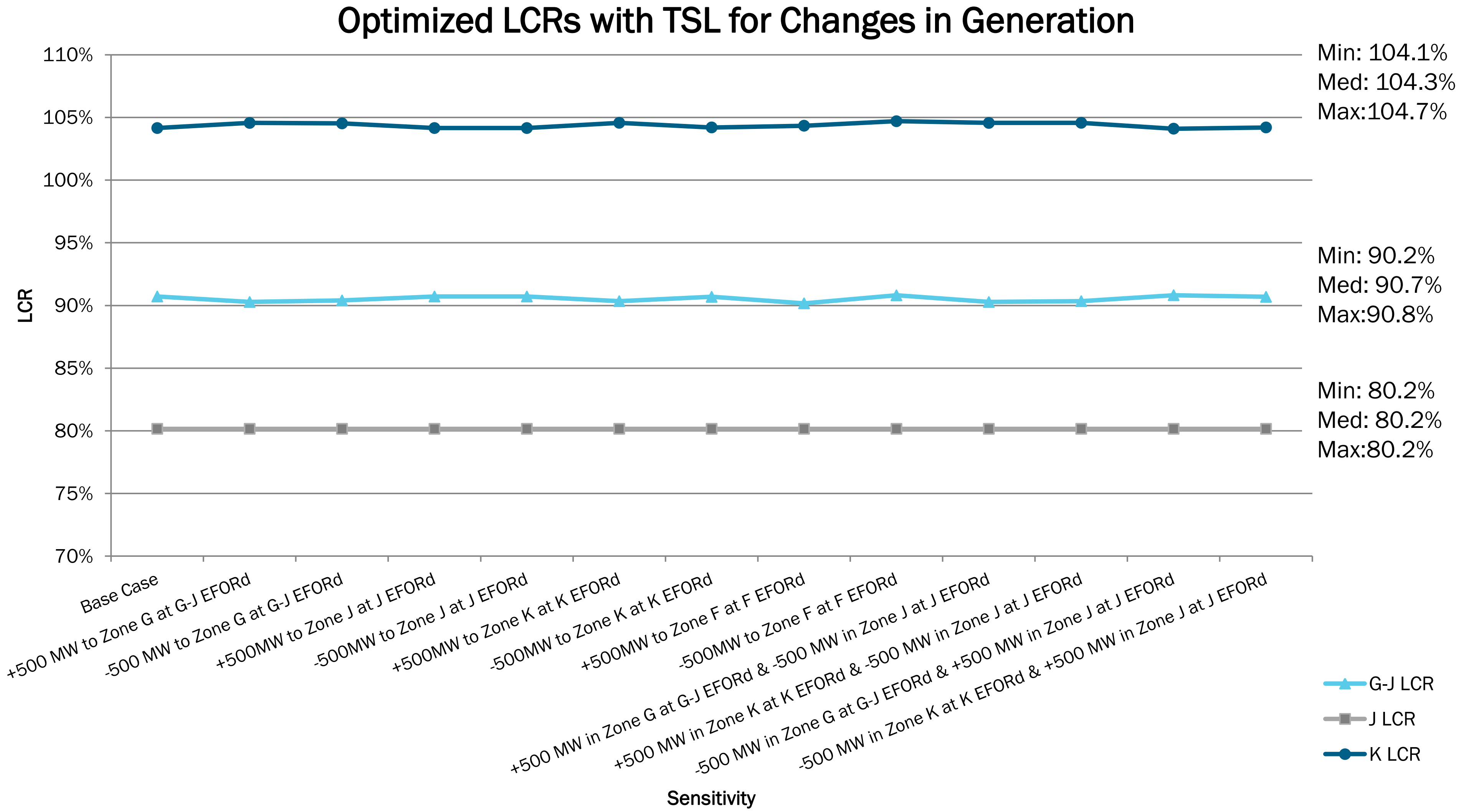
Sensitivity	Δ Cost at Historic Excess from Current LCR to Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
+1000 MW to UPNYSENY	$8.22	$9.86	-$46.53	$29.83	$1.37
+$25.00 to G-J	$12.26	-$15.16	-$8.93	$5.86	-$5.98
-$25.00 to G-J	-$1.15	-$15.16	$12.10	-$5.37	-$9.58
+$25.00 Zone J	$5.85	-$17.61	-$0.58	$3.34	-$9.01
-$25.00 to Zone J	$3.99	-$12.71	$2.45	$1.81	-$4.45
+$25.00 to Zone K	$7.35	-$41.02	$25.70	-$8.02	-$16.00
-$25.00 to Zone K	$4.78	-$15.16	-$1.20	$3.55	-$8.03
+$25.00 to NYCA	$0.64	-$15.16	$9.03	-$2.04	-$7.54
-$25.00 to NYCA	$5.80	-$15.16	-$0.46	$2.38	-$7.45
+500 MW in Zone G & -500 MW in Zone J	$6.22	$11.77	-$28.45	$15.44	$4.98
+500 MW in Zone K & -500 MW in Zone J	-$4.71	$9.25	-$1.63	$0.15	$3.06
-500 MW in Zone G & +500 MW in Zone J	$3.78	-$53.05	$27.42	-$3.81	-$25.67

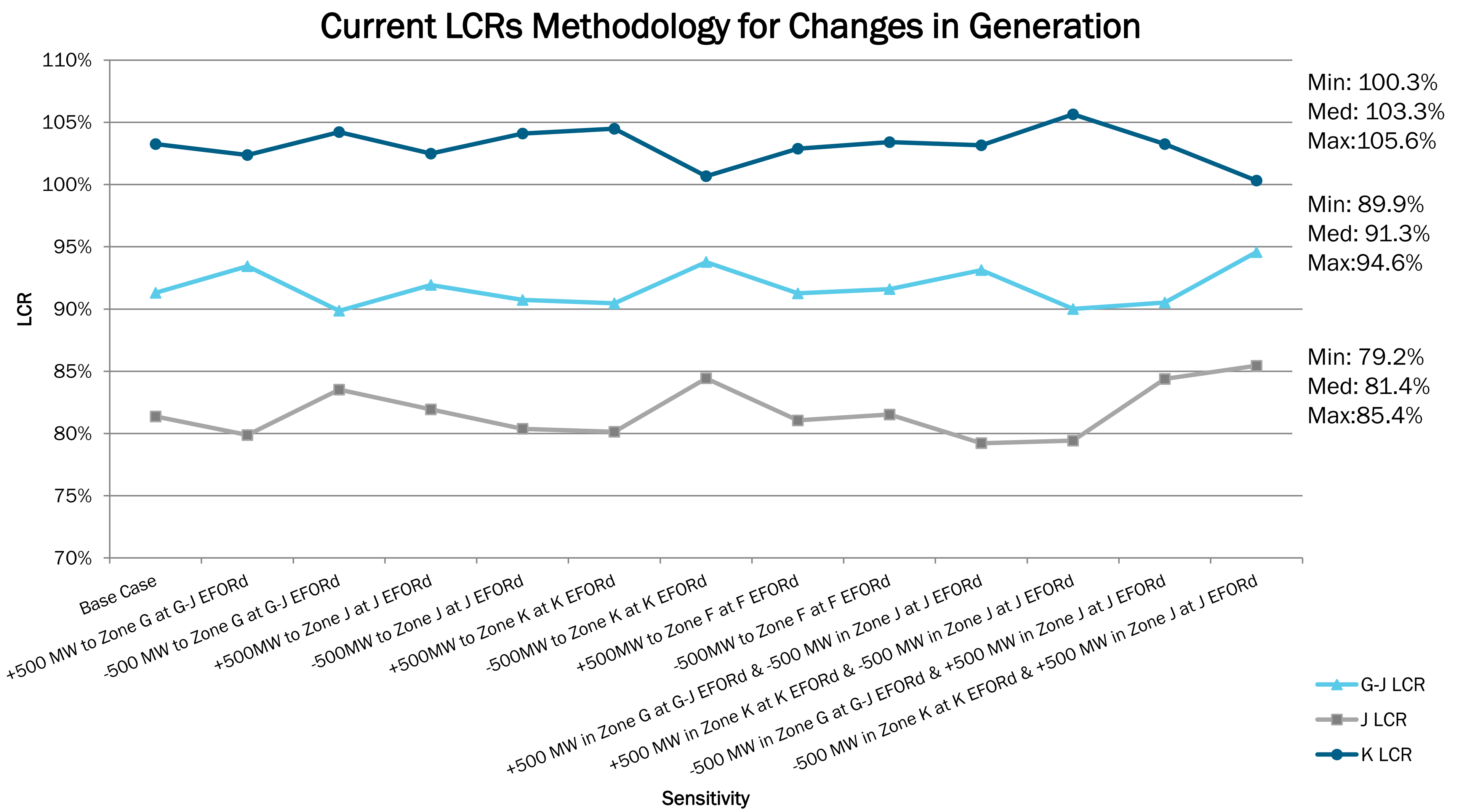
	Δ Cost at Historic Excess from Current LCR to Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
Minimum	-$4.71	-$66.35	-$46.53	-$8.02	-$32.36
25th percentile	$1.97	-$21.14	-$1.53	$0.01	-$9.86
Average	$5.50	-$18.01	-$0.52	$4.37	-$8.66
75th percentile	$7.38	-$4.86	$2.45	$5.45	-$2.10
Maximum	$17.16	$11.77	$27.42	$29.83	$4.98

Long Term Consumer Cost Impacts at Historic Excess

- Based on the sensitivities conducted, total long term NYCA consumer cost at historic excess is reduced in the majority of cases
  - The only cases that do not result in savings occur when the current LCR methodology results in a Zone J LCR lower than the Transmission Security Floor used in the optimization

Additional Factors


Optimized LCRs with TSL for Changes in Generation
110%
105%
100%
95%
90%
85%
80%
75%
70%
LCR
Min: 104.1%
Med: 104.3%
Max:104.7%
Min: 90.2%
Med: 90.7%
Max:90.8%
Min: 80.2%
Med: 80.2%
Max:80.2%
Base Case
+500 MW to Zone G at G-J EFORd
-500 MW to Zone G at G-J EFORd
+500MW to Zone J at J EFORd
-500MW to Zone J at J EFORd
+500MW to Zone K at K EFORd
-500MW to Zone K at K EFORd
+500MW to Zone F at F EFORd
-500MW to Zone F at F EFORd
+500 MW in Zone G at G-J EFORd & -500 MW in Zone J at J EFORd
+500 MW in Zone K at K EFORd & -500 MW in Zone J at J EFORd
-500 MW in Zone G at G-J EFORd & +500 MW in Zone J at J EFORd
-500 MW in Zone K at K EFORd & +500 MW in Zone J at J EFORd
Sensitivity
G-J LCR
J LCR
K LCR


Current LCRs Methodology for Changes in Generation
110%
105%
100%
95%
90%
85%
80%
75%
70%
LCR
Min: 100.3%
Med: 103.3%
Max:105.6%
Min: 89.9%
Med: 91.3%
Max:94.6%
Min: 79.2%
Med: 81.4%
Max:85.4%
Base Case
+500 MW to Zone G at G-J EFORd
-500 MW to Zone G at G-J EFORd
+500MW to Zone J at J EFORd
-500MW to Zone J at J EFORd
+500MW to Zone K at K EFORd
-500MW to Zone K at K EFORd
+500MW to Zone F at F EFORd
-500MW to Zone F at F EFORd
+500 MW in Zone G at G-J EFORd & -500 MW in Zone J at J EFORd
+500 MW in Zone K at K EFORd & -500 MW in Zone J at J EFORd
-500 MW in Zone G at G-J EFORd & +500 MW in Zone J at J EFORd
-500 MW in Zone K at K EFORd & +500 MW in Zone J at J EFORd
Sensitivity
G-J LCR
J LCR
K LCR

Stability of LCRs

- The optimization methodology results in an increase in stability as generation changes occur within the system

Methodology	Range of LCRs		
	Zone K	Zone J	G-J
Current LCR Methodology	5.3%	6.2%	4.7%
Optimized with TSL	0.6%	0.0%	0.7%

NEW YORK INDEPENDENT SYSTEM OPERATOR

Stability of LCRs

Methodology	Range of LCRs		
	Zone K	Zone J	G-J
Current LCR Methodology	289 MW	725 MW	756 MW
Optimized with TSL	32 MW	0 MW	104 MW

Other Impacts

Reliability Impact

- The alternate LCR methodology results in more stable and efficient LCRs than the current LCR methodology
- The increase in stability should improve market signals
- Stable and predictable market signals will lead to more efficient decisions in expanding and retiring assets, hence improving reliability
- Transmission Security Limits (TSL) further ensure that reliability is maintained at all times

Environmental Impact

- No change expected

Impact on Transparency

- More stable LCRs should enhance transparency as market response to changes in generation and/or reference prices will be more predictable than under the current LCR methodology

Feedback?

- Email additional feedback to:
- deckels@nyiso.com

Questions?

We are here to help. Let us know if we can add anything.

The Mission of the New York Independent System Operator, in collaboration with its stakeholders, is to serve the public interest and provide benefits to consumers by:

- Maintaining and enhancing regional reliability
- Operating open, fair and competitive wholesale electricity markets
- Planning the power system for the future
- Providing factual information to policy makers, stakeholders and investors in the power system

www.nyiso.com

NEW YORK INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY

Exhibit 27

Alternative Methods for Determining LCRs: Final Market Design

Zachary Stines
Associate Market Design Specialist

Installed Capacity Working Group

October 30, 2017, NYISO

DRAFT – FOR DISCUSSION PURPOSES ONLY

Agenda

- **2017 Project**
- **Final Market Design**
  - Design Objective
  - Methodology
  - Results
  - Transition Method
  - Cost Allocation
  - Timeline
- **Next Steps**
  - November 15 BIC
  - 2018 Project Scope
- **Questions**
- **Appendix**

2017 Project Presentations

2017 ICAPWG Presentations

Date	Discussion points and links to materials
2-15-17	Recap of 2016 Effort, 2017 Plan, and Current Status
4-04-17	2017 Commitment and Base Case
5-11-17	Proof of Concept and Refining Methodology
6-01-17	Sensitivities and Cost Curves
6-29-17	Sensitivity Results and Refining Methodology
7-25-17	Refining Methodology
8-22-17	Refining Methodology and Transmission Security
9-28-17	Transmission Security, Results, and Timeline

Final Market Design

Design Objective

Market Design Statement

Develop a robust, transparent, and intuitive (predictive) process for developing proper capacity requirements that maintain reliability while producing a lower cost solution

Market Guiding Principles

Efficient allocation of capacity

- Maintains reliability
- Cost effective
- Proper investment incentives

Transparent and predictable

- Simple, stable, robust
- Predictable

NEW YORK INDEPENDENT SYSTEM OPERATOR

Methodology

Optimization Methodology

- Determine LCRs for the Localities that minimize total cost of capacity at the level of excess (LOE) condition while maintaining the reliability criterion (LOLE ≤ 0.1 days/year), the NYSRC approved IRM, and not exceeding transmission security limits (TSL)
- Cost defined by Unit Net CONE used to develop each ICAP Demand Curve

NEW YORK INDEPENDENT SYSTEM OPERATOR

Minimize:

$$
\begin{aligned}
&\mathit{Total\ Cost\ of\ Capacity} \\
&= \left[\sum_{X}(Q_X + LOE_X)\cdot P_X(Q_X + LOE_X)\right] \\
&+ \left[\sum_{Y}(Q_Y + LOE_Y)\cdot P_Y\left(Q_Y + LOE_Y + \sum_{Z} Q_Z + LOE_Z\right)\right] \\
&+ \left[\left(Q_{NYCA} + LOE_{NYCA} - \left(\sum_{X}(Q_X + LOE_X) + \sum_{Y}(Q_Y + LOE_Y)\right)\right) \right. \\
&\left. \cdot P_{NYCA}(Q_{NYCA} + LOE_{NYCA})\right]
\end{aligned}
$$

NEW YORK INDEPENDENT SYSTEM OPERATOR

$P =$ Price (*i.e.*, Unit Net CONE curves)

$Q =$ Quantity at 100% requirement (MW)

$LOE =$ Quantity associated with Level of Excess (MW)

$X =$ Single Load Zone that is a Locality (*i.e.*, Zone J and Zone K)

$Y =$ Locality minus any Single Load Zone Locality located within it (*i.e.*, GHI)

$Z =$ Single Locality located within a larger Locality (*i.e.*, Zone J)

$NYCA =$ New York Control Area

Subject to:

$$LOLE \leq 0.1\ days/year$$

$$LCR_J \geq TSL_J$$

$$LCR_K \geq TSL_K$$

$$LCR_{G\text{-}J} \geq TSL_{G\text{-}J}$$

$$IRM = NYSRC\ Approved\ IRM\ (i.e.,\ 18\%)$$

Computational Method: Linear Approximation

- Iterative process between Linear Program wrapper and MARS that approximates the objective function and constraints to find least cost solution
- Currently uses the Constrained Optimization By Linear Approximation (COBYLA) algorithm available through Python's scientific computing package

MARS Modeling Assumptions

- Utilize the same process as currently used to develop the final LCR base case
  - Update the NYSRC approved final IRM topology to account for the updated load forecast
- Optimize with the appropriate NYSRC final approved IRM

Cost of Capacity

- Based upon ICAP Demand Curve peaking plant net cost of new entry (“DC unit net CONE”) of capacity within each Locality and the NYCA
- Based upon the FERC accepted Demand Curve parameters
- Elasticity is represented by expressing the DC unit net CONE of each Locality and NYCA as a function of the minimum installed capacity requirement

Development of DC unit net CONE Curves

- **Evaluate Net EAS at different levels of installed capacity using data from the 2016 Demand Curve Reset process**
  - Net EAS for each Locality was evaluated at +6%, +3%, 2016 requirement, -3%, and -6% of the installed capacity requirement
- **Results are used to develop a Net EAS curve**
- **The Net EAS at each point on the curve is used to calculate a corresponding Net CONE**
- **Net CONE values are used to develop a DC unit net CONE curve for each Locality and NYCA**

Transmission Security Methodology

- N-1-1 analysis is conducted to determine the transmission security import limits into each Locality
- These import limits are used to determine the minimum available capacity required for each Locality
- To translate this minimum available capacity into a market requirement the methodology needs to account for capacity unavailability
- To account for capacity unavailability, the 5-year zonal EFORd is used to calculate minimum locational capacity requirements

N-1-1 Transmission Security Limit (TSL) Analysis

- **Analyzes the N-1-1 thermal transfer limits for the NYCA interfaces associated with the G-J, Zone J, and Zone K Localities**
- **Use an updated Summer Operating base case**
  - Inclusion of transmission and generation facility additions and retirements
  - All system elements modeled as in service
  - Appropriate load forecast
- **Report with N-1-1 import limits will be posted prior to October 1st of each year**
- **Final TSLs for the optimization will be established and posted in January each year**

Example Calculation

Transmission Security Requirements	Formula	Zone X
Load Forecast (MW)	[A] = Given	12,000
Transmission Security Import Limit (MW)	[B] = Given	1,500
Transmission Security UCAP Requirement (MW)	[C] = [A]-[B]	10,500
Transmission Security UCAP Requirement (%)	[D] = [C]/[A]	87.5%
5 Year EFORd (%)	[E] = Given	8.0%
Transmission Security ICAP Requirement (MW)	[F] = [C]/(1-[E])	11,413
Transmission Security LCR Floor (%)	[G] = [F]/[A]	**95.1%**

NEW YORK INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY

Results

Base Case

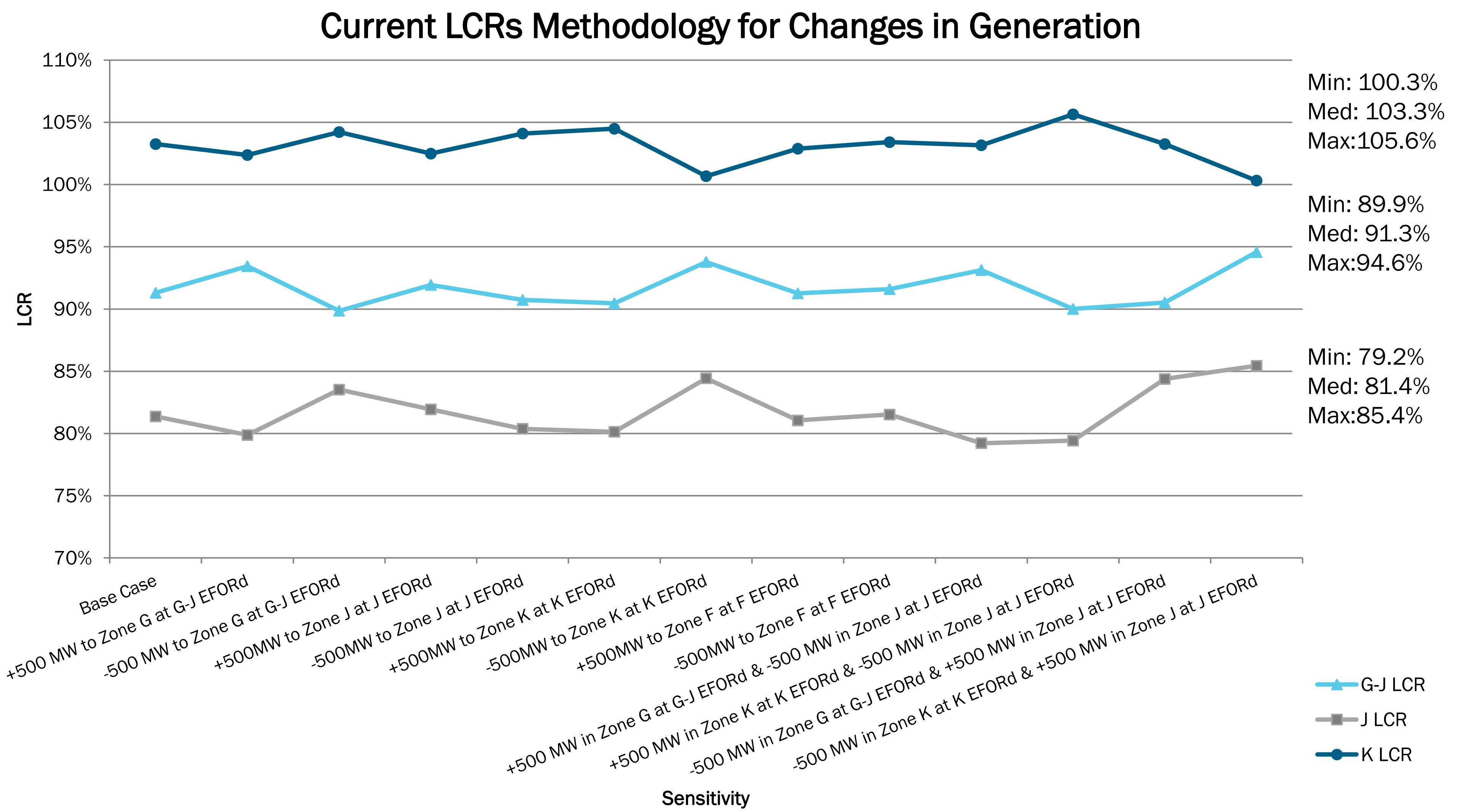
Scenario	Zone J LCR	Zone K LCR	G-J LCR	Cost ($ million)
Current LCR Methodology	81.4%	103.2%	91.3%	$4,441.90
Optimized Methodology without Transmission Security Limits (TSL)	78.0%	105.3%	91.5%	$4,402.89
Optimized Methodology with Transmission Security Limits (TSL)	**80.16%**	**104.15%**	**90.71%**	**$4,424.37**

Base Case

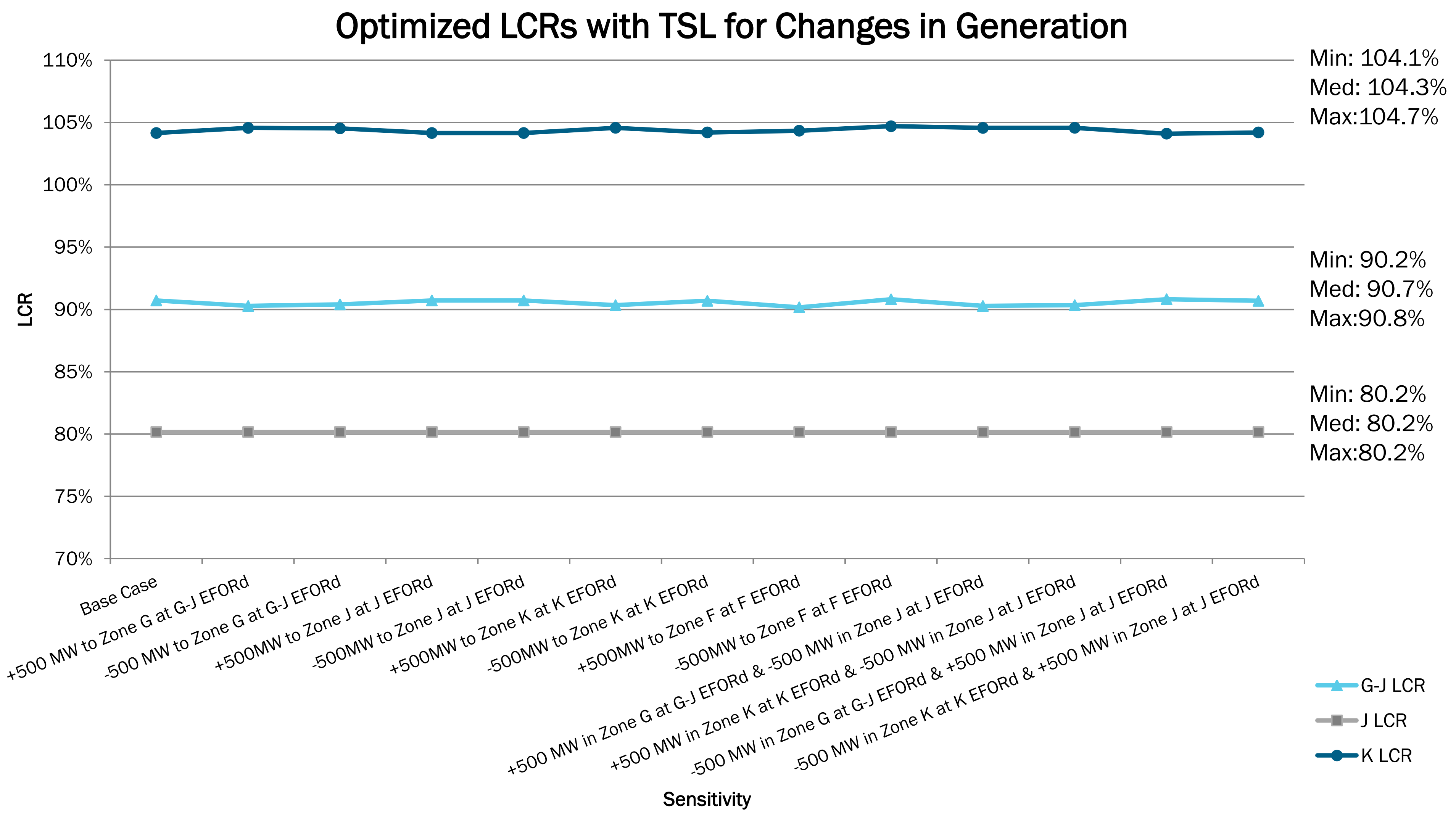
Scenario	Zone J LCR	Zone K LCR	G-J LCR
Current LCR Methodology	9,495 MW	5,603 MW	14,664 MW
Optimized Methodology without Transmission Security Limits (TSL)	9,102 MW	5,715 MW	14,696 MW
Optimized Methodology with Transmission Security Limits (TSL)	**9,355 MW**	**5,652 MW**	**14,570 MW**

NEW YORK INDEPENDENT SYSTEM OPERATOR

Market Stability with Changes in Generation



Current LCRs Methodology for Changes in Generation
110%
105%
100%
95%
90%
85%
80%
75%
70%
LCR
Min: 100.3%
Med: 103.3%
Max:105.6%
Min: 89.9%
Med: 91.3%
Max:94.6%
Min: 79.2%
Med: 81.4%
Max:85.4%
Base Case
+500 MW to Zone G at G-J EFORd
-500 MW to Zone G at G-J EFORd
+500MW to Zone J at J EFORd
-500MW to Zone J at J EFORd
+500MW to Zone K at K EFORd
-500MW to Zone K at K EFORd
+500MW to Zone F at F EFORd
-500MW to Zone F at F EFORd
+500 MW in Zone G at G-J EFORd & -500 MW in Zone J at J EFORd
+500 MW in Zone K at K EFORd & -500 MW in Zone J at J EFORd
-500 MW in Zone G at G-J EFORd & +500 MW in Zone J at J EFORd
-500 MW in Zone K at K EFORd & +500 MW in Zone J at J EFORd
Sensitivity
G-J LCR
J LCR
K LCR



Optimized LCRs with TSL for Changes in Generation
110%
105%
100%
95%
90%
85%
80%
75%
70%
LCR
Min: 104.1%
Med: 104.3%
Max:104.7%
Min: 90.2%
Med: 90.7%
Max:90.8%
Min: 80.2%
Med: 80.2%
Max:80.2%
Base Case
+500 MW to Zone G at G-J EFORd
-500 MW to Zone G at G-J EFORd
+500MW to Zone J at J EFORd
-500MW to Zone J at J EFORd
+500MW to Zone K at K EFORd
-500MW to Zone K at K EFORd
+500MW to Zone F at F EFORd
-500MW to Zone F at F EFORd
+500 MW in Zone G at G-J EFORd & -500 MW in Zone J at J EFORd
+500 MW in Zone K at K EFORd & -500 MW in Zone J at J EFORd
-500 MW in Zone G at G-J EFORd & +500 MW in Zone J at J EFORd
-500 MW in Zone K at K EFORd & +500 MW in Zone J at J EFORd
Sensitivity
G-J LCR
J LCR
K LCR

Stability of LCRs

- The optimization methodology results in an increase in stability as generation changes occur within the system

Methodology	Range of LCRs in Change in Generation Sensitivities		
	Zone K	Zone J	G-J
Current LCR Methodology	5.3%	6.2%	4.7%
Optimized with TSL	0.6%	0.0%	0.7%

NEW YORK INDEPENDENT SYSTEM OPERATOR

Stability of LCRs

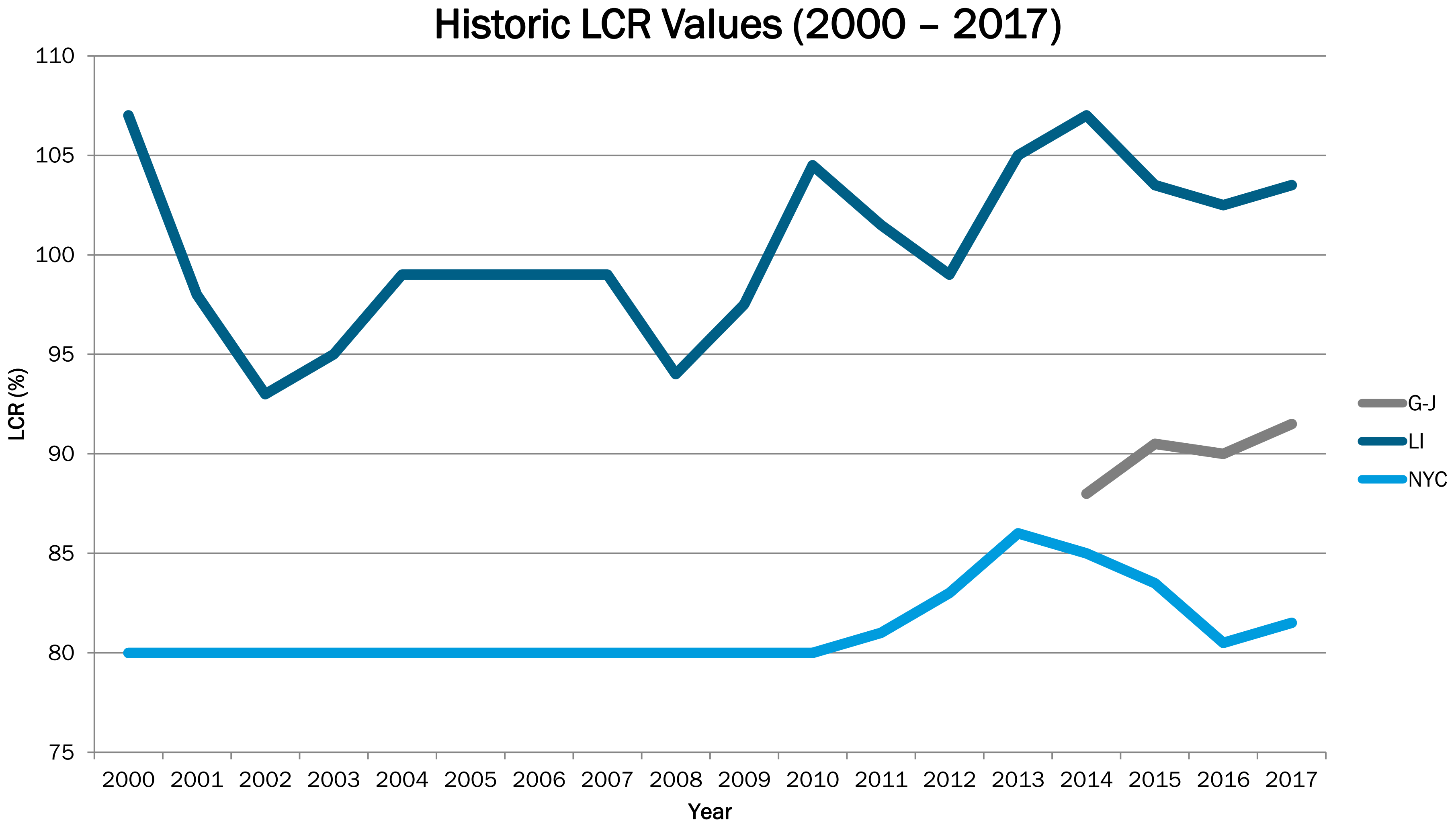
Methodology	Range of LCRs		
	Zone K	Zone J	G-J
Current LCR Methodology	289 MW	725 MW	756 MW
Optimized with TSL	32 MW	0 MW	104 MW

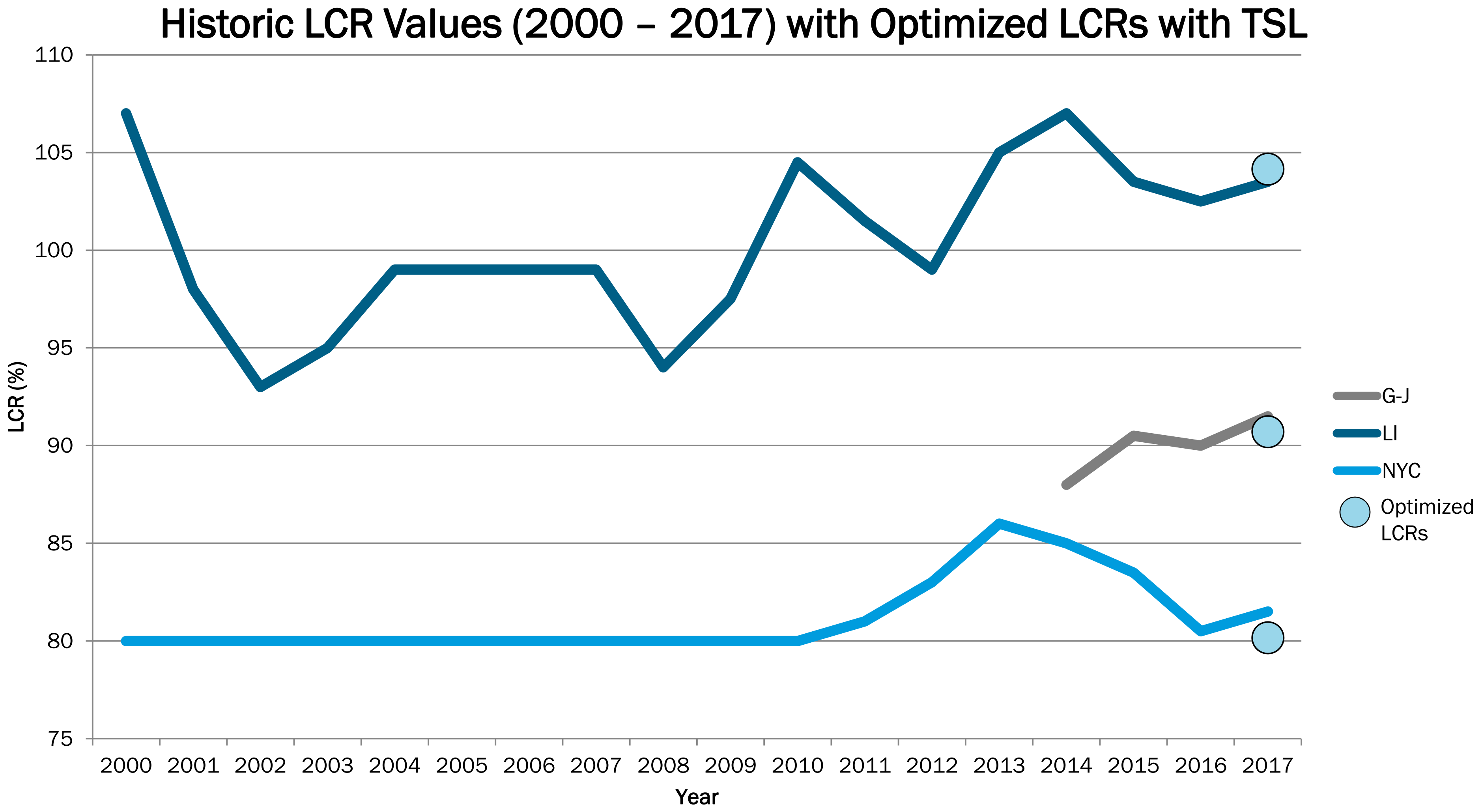
Review of Potential Inclusion of Cost Allocation Provision

Historic LCR Values for last 5 years (2013-2017)

	Zone J	Zone K	G-J*
Minimum	80.5%	102.5%	88.0%
Average	83.3%	103.4%	90.0%
Maximum	86.0%	107.0%	91.5%
Optimized Methodology with Transmission Security Limits (TSL)	80.16%	104.15%	90.71%

*LCRs were established for G-J starting in 2014


Historic LCR Values (2000 – 2017)
LCR (%)
110
105
100
95
90
85
80
75
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
Year
G-J
LI
NYC



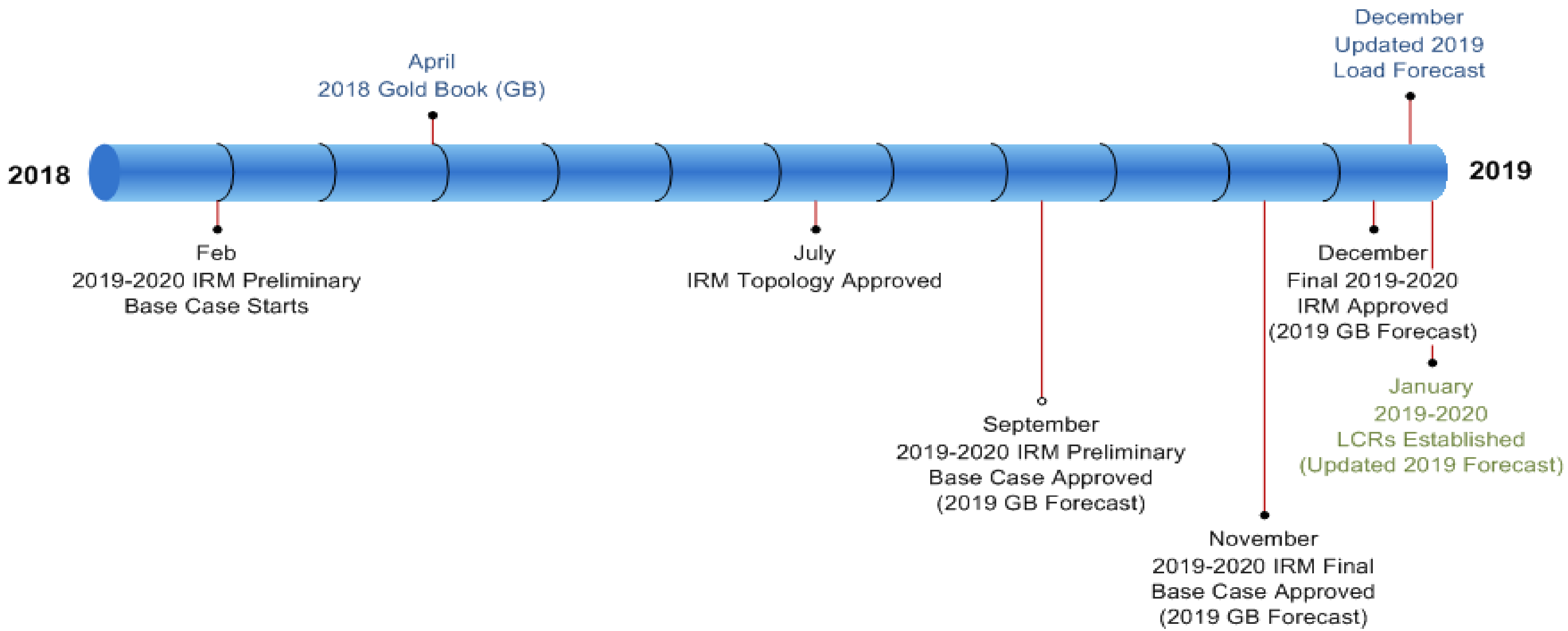
Historic LCR Values (2000 – 2017) with Optimized LCRs with TSL
110
105
100
95
90
85
80
75
LCR (%)
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
Year
G-J
LI
NYC
Optimized LCRs

Cost Allocation

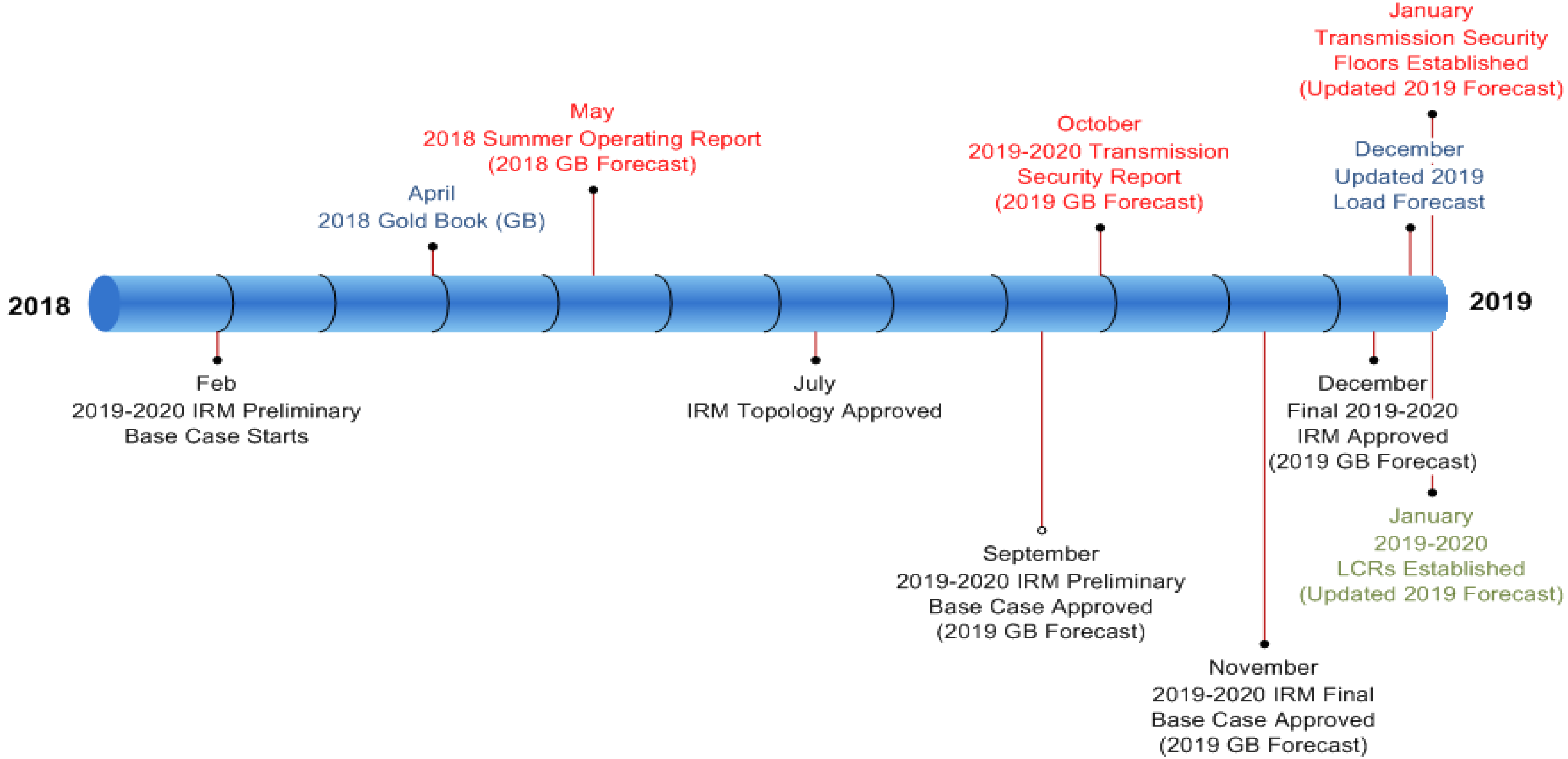
- Since the optimization methodology results in LCRs within the historic range, an evaluation of a potential revision to the cost allocation that results appears to be unnecessary
  - In addition, the optimization is providing increased market stability with respect to changes in generation
- If conditions should occur that warrant reviewing and revising cost allocation methodology, the NYISO and stakeholders could take it into consideration. In addition, stakeholders may prioritize it in a future BPWG process as a future project

Timeline

Current Timeline



Timeline Additions



LCR Setting Timeline

- No alterations to the current timeline are needed to accommodate the alternative methodology for determining LCRs
- Transmission security analysis used in the alternative methodology would be conducted and reported prior to October 1st
  - This analysis would utilize an updated base case used in the Summer Operating Report

Next Steps

November 15th BIC

- The NYISO will present this complete market design to the November 15th BIC meeting to propose the optimized methodology for determining LCRs as outlined in this presentation be pursued
- This milestone will confirm stakeholder support for the market design and methodology as it has developed in the 2017 project
- The vote will also be used by the NYISO to efficiently allocate resources
  - Tariff development will be undertaken only if proposal has broad stakeholder support
  - Will determine if the 2018 Alternative Methods for LCRs will continue as currently defined

2018 Project Scope

- Review existing Tariff language and draft Tariff language to reflect new methodology as necessary
  - Take to BIC and MC for action, and Board approval
- File revised Tariff language with FERC
- Revise LCR methodology documentation and any manual revisions required
- Develop internal process for implementation
- Address any administrative issues (ongoing)

Other Next Steps

- The NYISO will consider input received during today's ICAP Working Group meeting
- Additional comments sent to deckels@nyiso.com will be considered

Questions?

The Mission of the New York Independent System Operator, in collaboration with its stakeholders, is to serve the public interest and provide benefits to consumers by:

- Maintaining and enhancing regional reliability
- Operating open, fair and competitive wholesale electricity markets
- Planning the power system for the future
- Providing factual information to policy makers, stakeholders and investors in the power system

www.nyiso.com

NEW YORK INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY

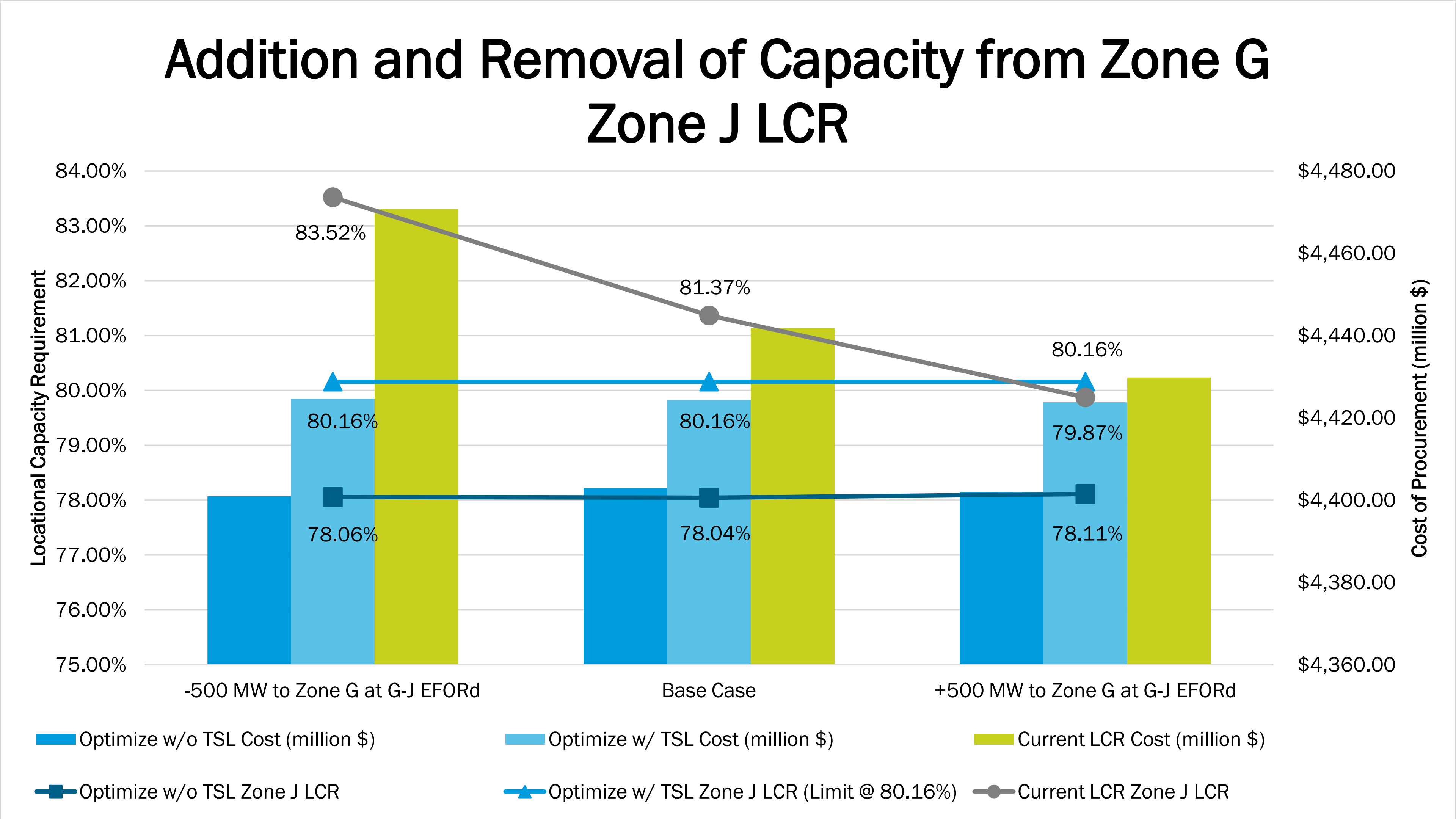
Appendix

NEW YORK INDEPENDENT SYSTEM OPERATOR

Single Change in Generation

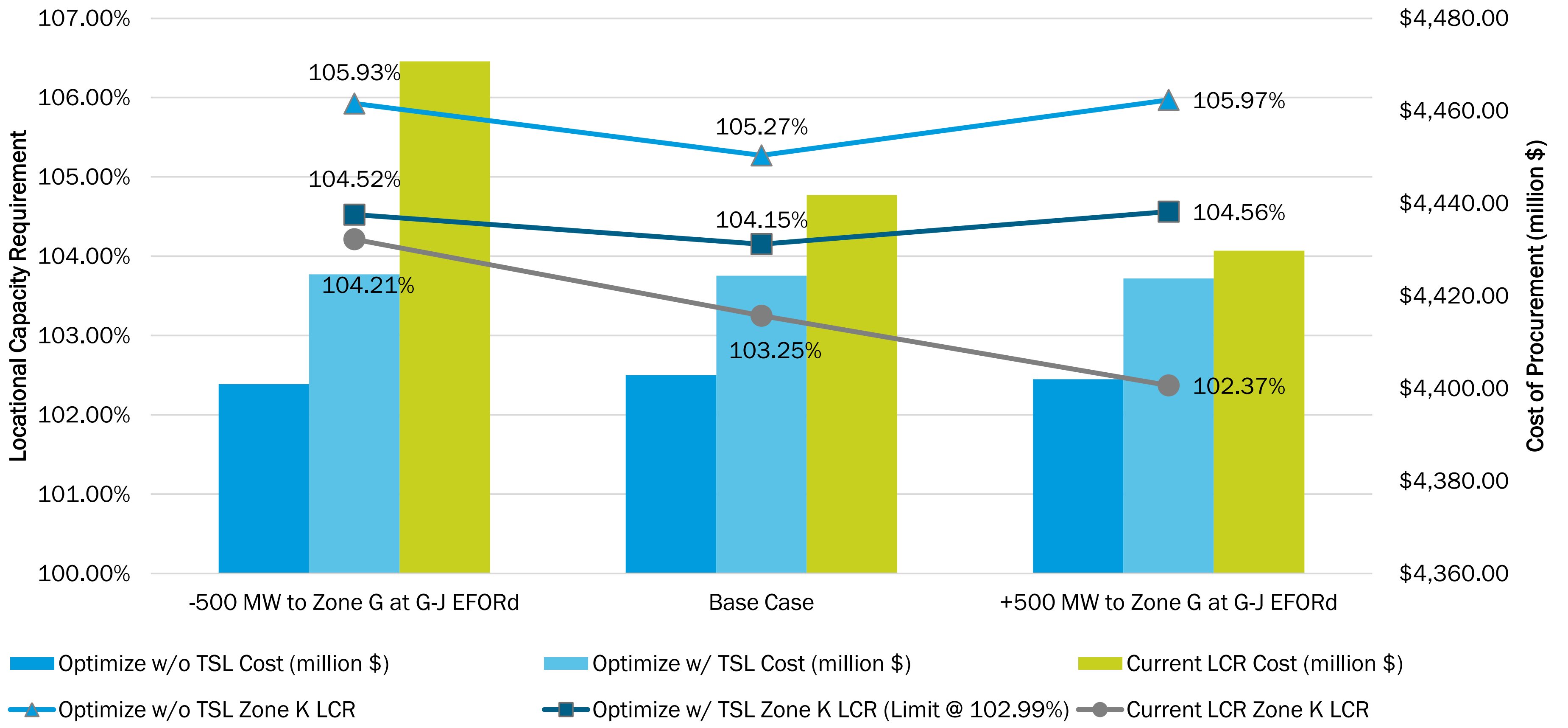
- +/- 500 MW to Zone G at G-J EFORd
- +/- 500 MW to Zone J at J EFORd
- +/- 500 MW to Zone K at K EFORd
- +/- 500 MW to Zone F at F EFORd

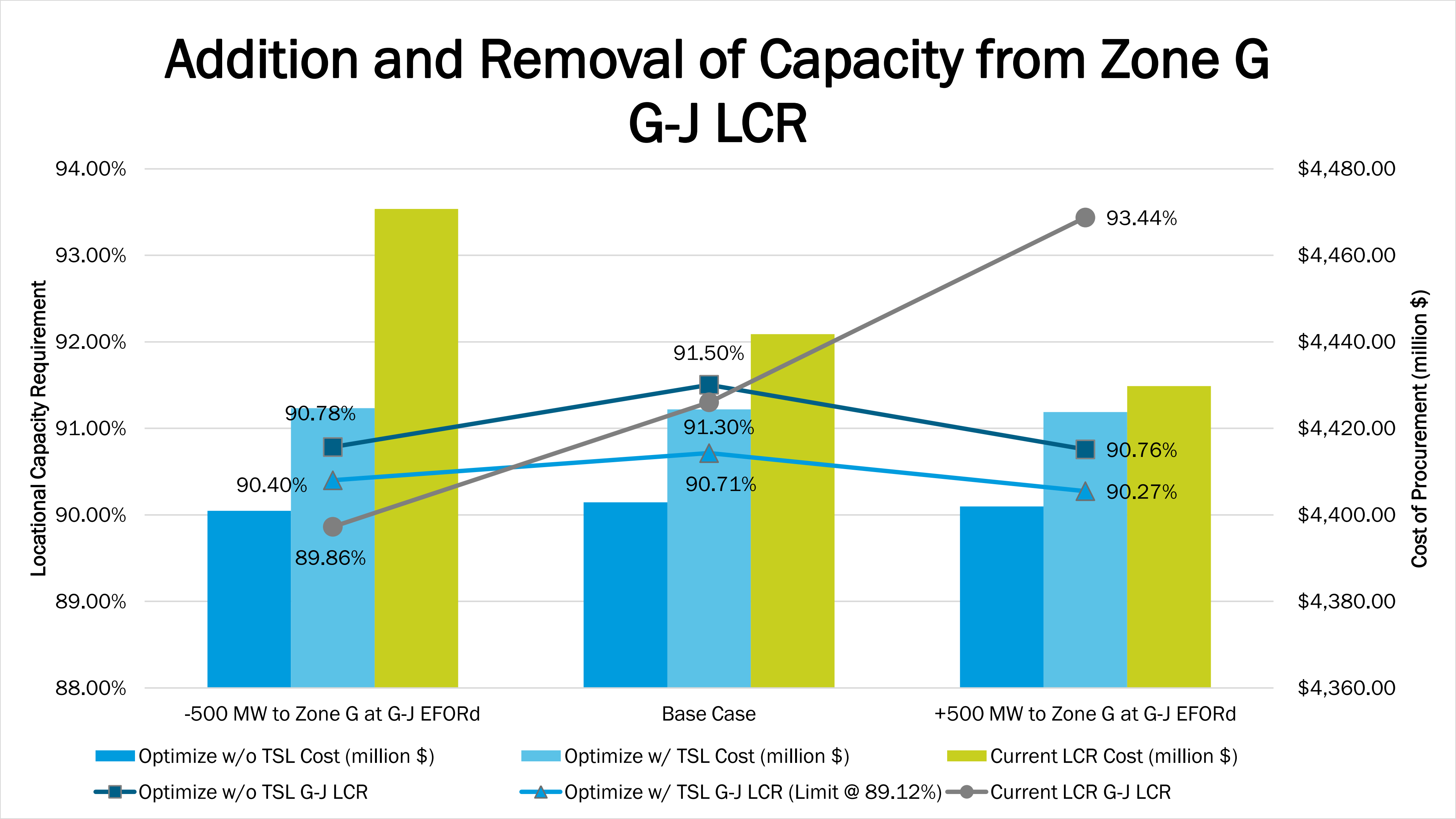
Market Simulations: +/- 500 MW to Zone G



Addition and Removal of Capacity from Zone G
Zone J LCR
Locational Capacity Requirement
Cost of Procurement (million $)
84.00%
83.00%
82.00%
81.00%
80.00%
79.00%
78.00%
77.00%
76.00%
75.00%
$4,480.00
$4,460.00
$4,440.00
$4,420.00
$4,400.00
$4,380.00
$4,360.00
83.52%
81.37%
80.16%
80.16%
80.16%
79.87%
78.06%
78.04%
78.11%
-500 MW to Zone G at G-J EFORd
Base Case
+500 MW to Zone G at G-J EFORd
Optimize w/o TSL Cost (million $)
Optimize w/ TSL Cost (million $)
Current LCR Cost (million $)
Optimize w/o TSL Zone J LCR
Optimize w/ TSL Zone J LCR (Limit @ 80.16%)
Current LCR Zone J LCR

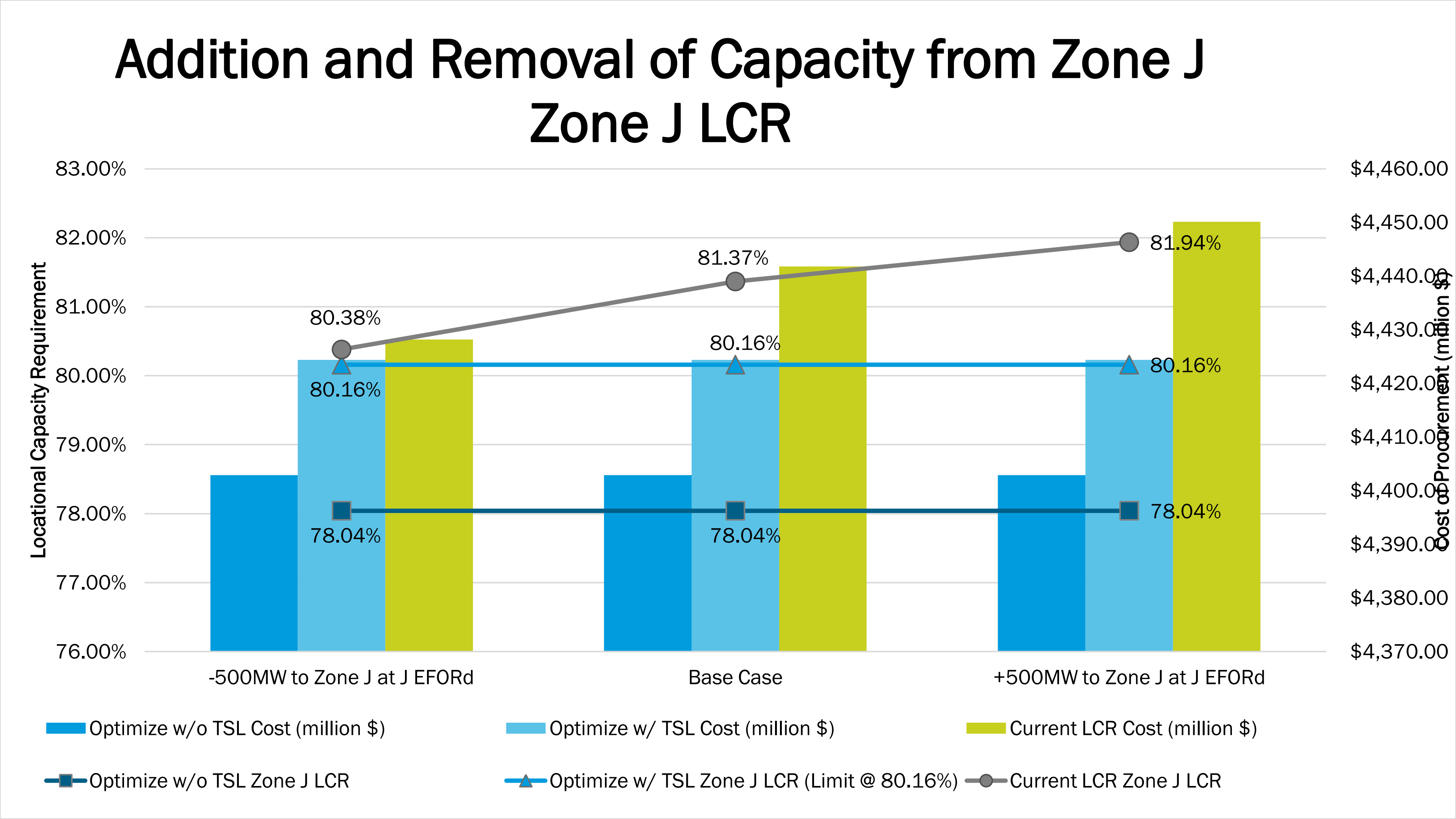
Addition and Removal of Capacity from Zone G Zone K LCR

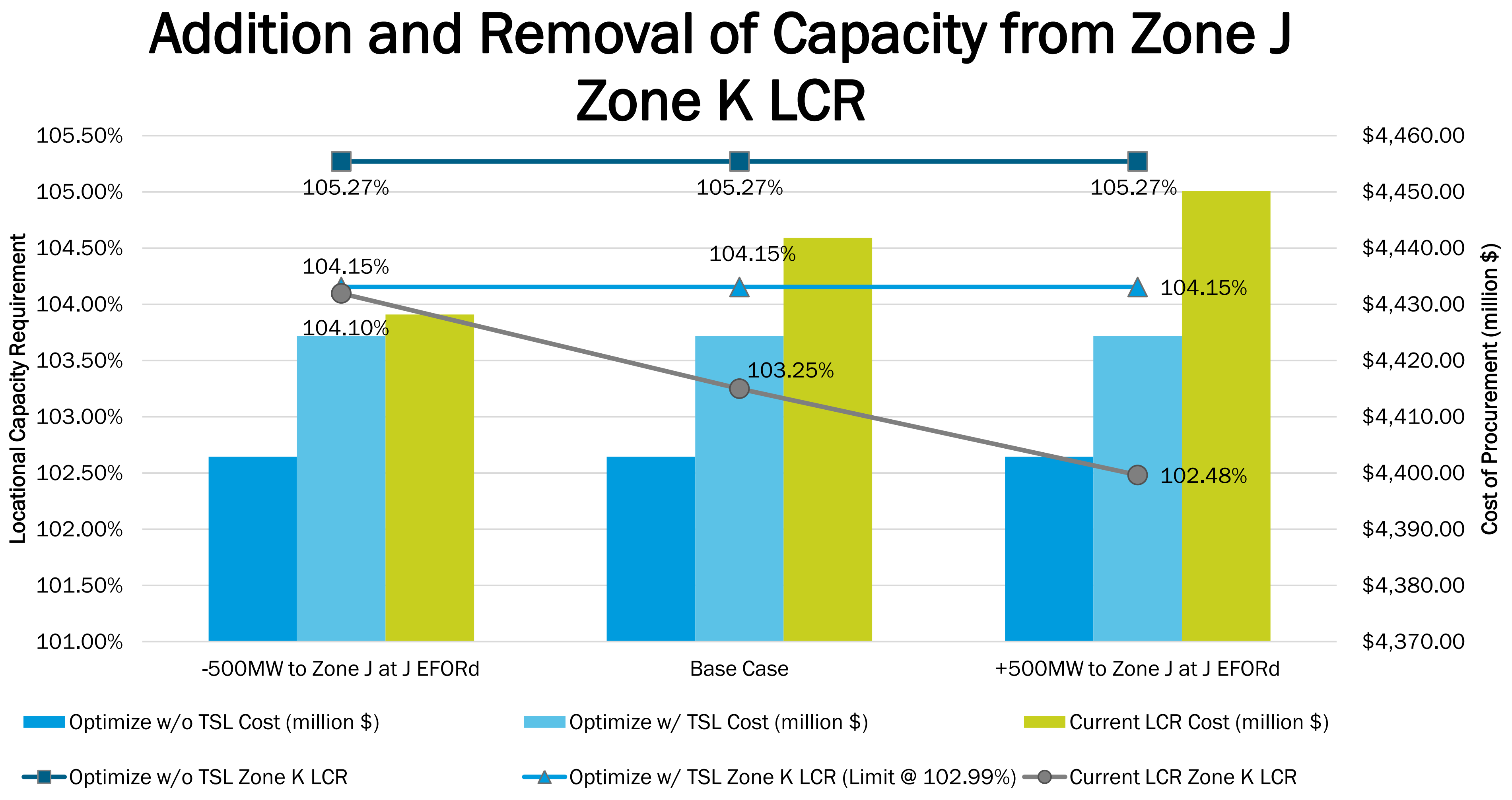




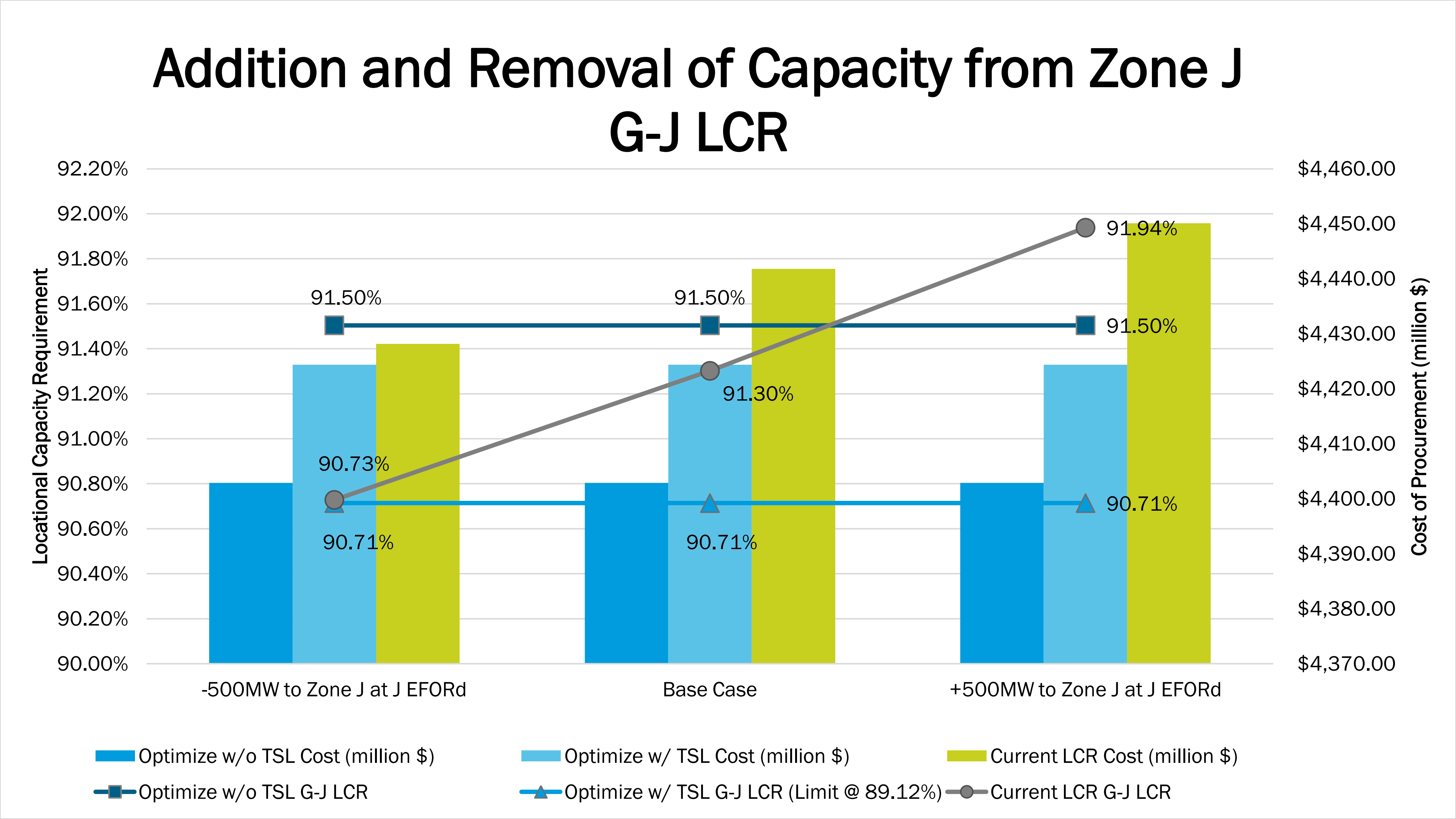
Addition and Removal of Capacity from Zone G
G-J LCR
Locational Capacity Requirement
Cost of Procurement (million $)
94.00%
93.00%
92.00%
91.00%
90.00%
89.00%
88.00%
$4,480.00
$4,460.00
$4,440.00
$4,420.00
$4,400.00
$4,380.00
$4,360.00
93.44%
91.50%
90.78%
91.30%
90.76%
90.40%
90.71%
90.27%
89.86%
-500 MW to Zone G at G-J EFORd
Base Case
+500 MW to Zone G at G-J EFORd
Optimize w/o TSL Cost (million $)
Optimize w/ TSL Cost (million $)
Current LCR Cost (million $)
Optimize w/o TSL G-J LCR
Optimize w/ TSL G-J LCR (Limit @ 89.12%)
Current LCR G-J LCR

Market Simulations: +/- 500 MW to Zone J


Addition and Removal of Capacity from Zone J
Zone J LCR
Locational Capacity Requirement
Cost of Procurement (million $)
83.00%
82.00%
81.00%
80.00%
79.00%
78.00%
77.00%
76.00%
$4,460.00
$4,450.00
$4,440.00
$4,430.00
$4,420.00
$4,410.00
$4,400.00
$4,390.00
$4,380.00
$4,370.00
80.38%
81.37%
81.94%
80.16%
80.16%
80.16%
78.04%
78.04%
78.04%
-500MW to Zone J at J EFORd
Base Case
+500MW to Zone J at J EFORd
Optimize w/o TSL Cost (million $)
Optimize w/ TSL Cost (million $)
Current LCR Cost (million $)
Optimize w/o TSL Zone J LCR
Optimize w/ TSL Zone J LCR (Limit @ 80.16%)
Current LCR Zone J LCR

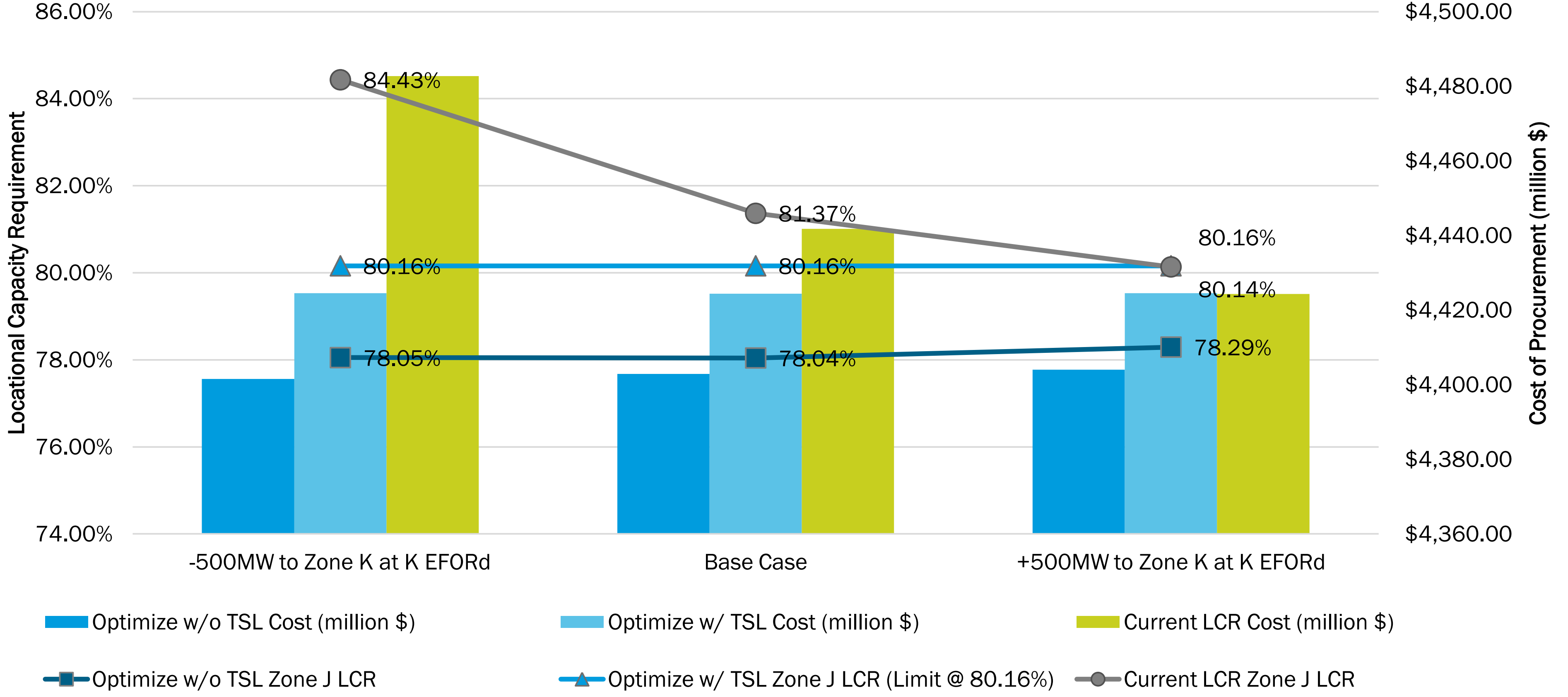


Addition and Removal of Capacity from Zone J
Zone K LCR
Locational Capacity Requirement
Cost of Procurement (million $)
105.50%
105.00%
104.50%
104.00%
103.50%
103.00%
102.50%
102.00%
101.50%
101.00%
$4,460.00
$4,450.00
$4,440.00
$4,430.00
$4,420.00
$4,410.00
$4,400.00
$4,390.00
$4,380.00
$4,370.00
105.27%
105.27%
105.27%
104.15%
104.15%
104.15%
104.10%
103.25%
102.48%
-500MW to Zone J at J EFORd
Base Case
+500MW to Zone J at J EFORd
Optimize w/o TSL Cost (million $)
Optimize w/ TSL Cost (million $)
Current LCR Cost (million $)
Optimize w/o TSL Zone K LCR
Optimize w/ TSL Zone K LCR (Limit @ 102.99%)
Current LCR Zone K LCR

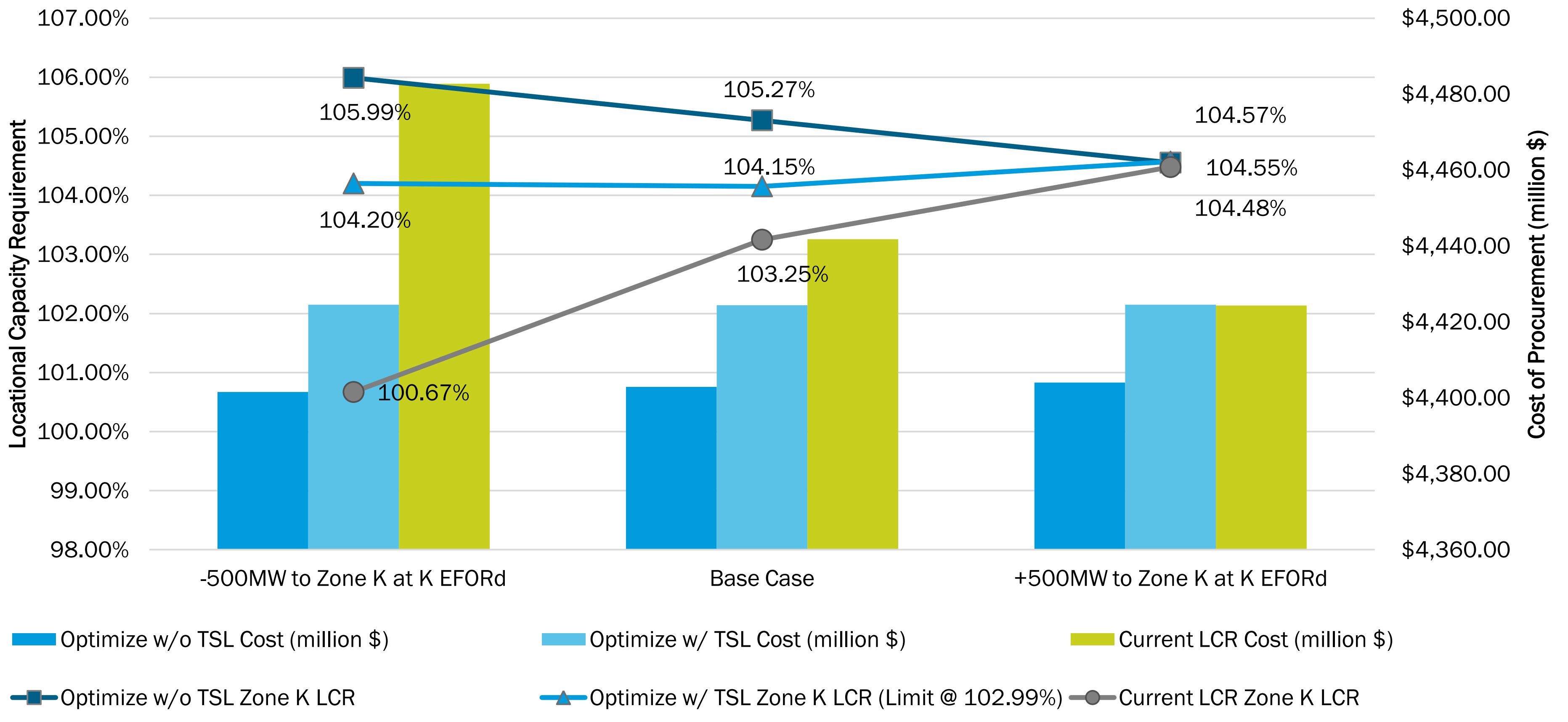

Addition and Removal of Capacity from Zone J
G-J LCR
Locational Capacity Requirement
Cost of Procurement (million $)
92.20%
92.00%
91.80%
91.60%
91.40%
91.20%
91.00%
90.80%
90.60%
90.40%
90.20%
90.00%
$4,460.00
$4,450.00
$4,440.00
$4,430.00
$4,420.00
$4,410.00
$4,400.00
$4,390.00
$4,380.00
$4,370.00
91.50%
91.50%
91.50%
91.94%
91.30%
90.73%
90.71%
90.71%
90.71%
-500MW to Zone J at J EFORd
Base Case
+500MW to Zone J at J EFORd
Optimize w/o TSL Cost (million $)
Optimize w/ TSL Cost (million $)
Current LCR Cost (million $)
Optimize w/o TSL G-J LCR
Optimize w/ TSL G-J LCR (Limit @ 89.12%)
Current LCR G-J LCR

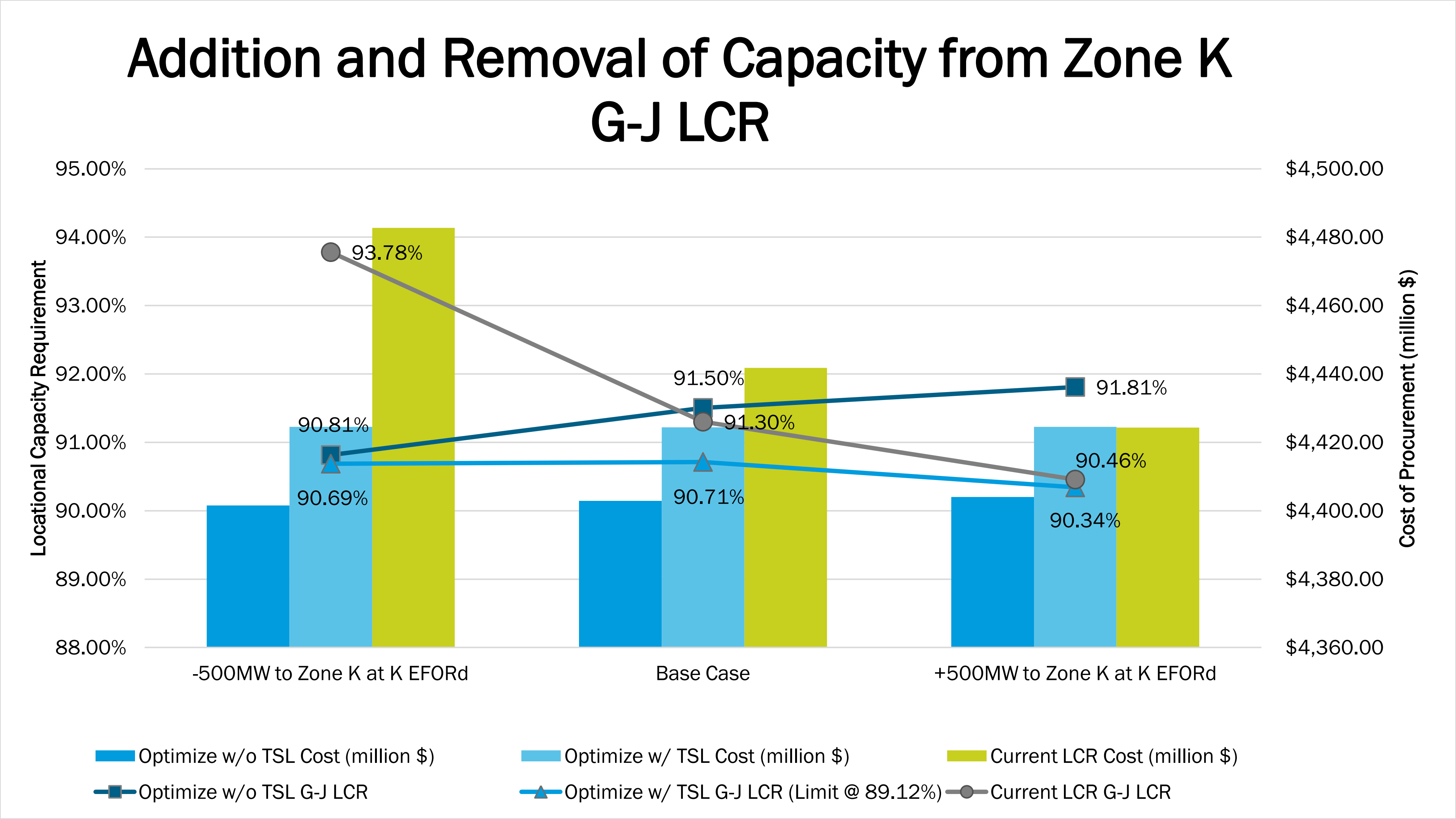
Market Simulations:
+/- 500 MW to Zone K

Addition and Removal of Capacity from Zone K
Zone J LCR



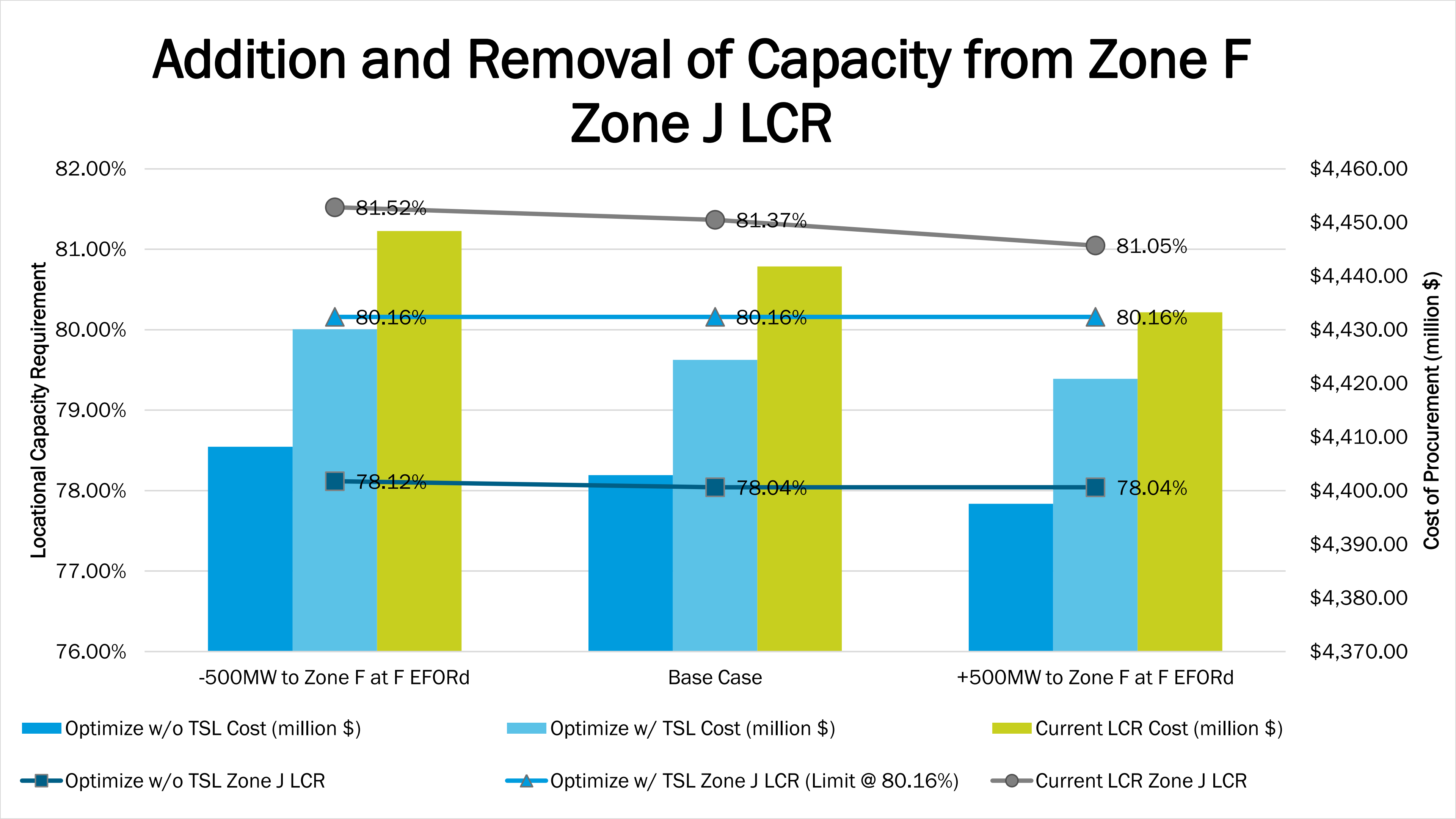
Addition and Removal of Capacity from Zone K
Zone K LCR

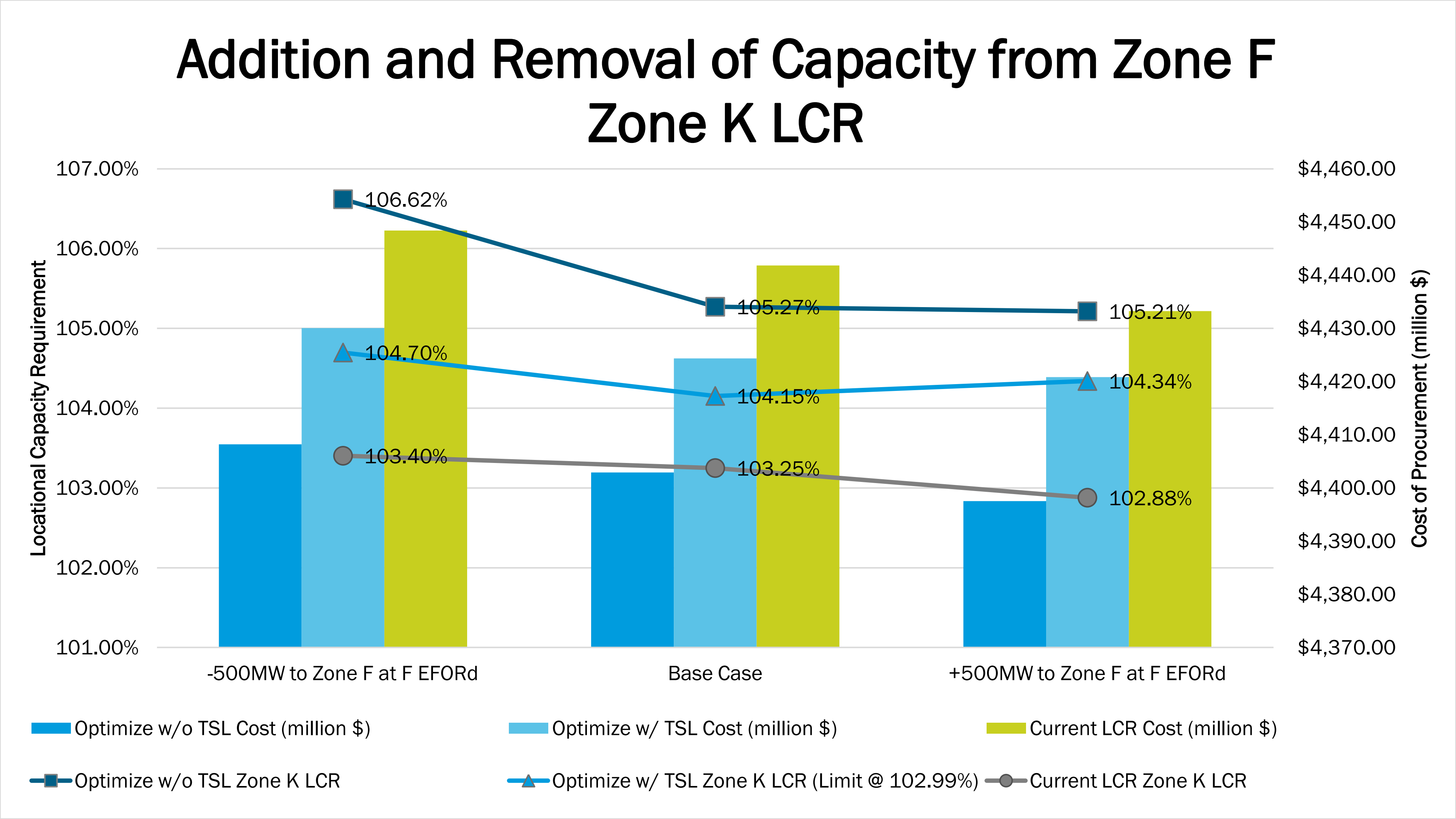




Addition and Removal of Capacity from Zone K
G-J LCR
Locational Capacity Requirement
Cost of Procurement (million $)
95.00%
94.00%
93.00%
92.00%
91.00%
90.00%
89.00%
88.00%
$4,500.00
$4,480.00
$4,460.00
$4,440.00
$4,420.00
$4,400.00
$4,380.00
$4,360.00
93.78%
90.81%
90.69%
91.50%
91.30%
90.71%
91.81%
90.46%
90.34%
-500MW to Zone K at K EFORd
Base Case
+500MW to Zone K at K EFORd
Optimize w/o TSL Cost (million $)
Optimize w/ TSL Cost (million $)
Current LCR Cost (million $)
Optimize w/o TSL G-J LCR
Optimize w/ TSL G-J LCR (Limit @ 89.12%)
Current LCR G-J LCR

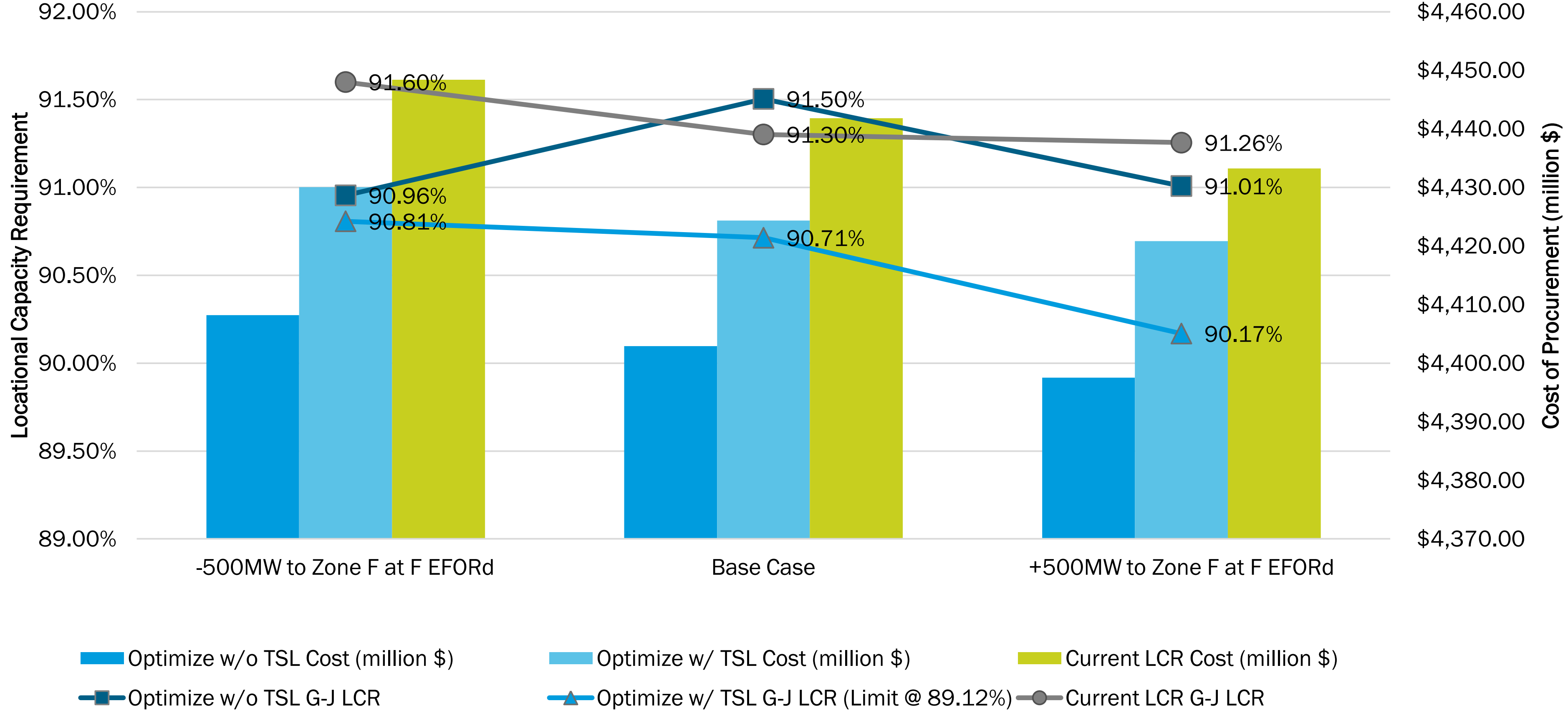
Market Simulations: +/- 500 MW to Zone F


Addition and Removal of Capacity from Zone F
Zone J LCR
Locational Capacity Requirement
Cost of Procurement (million $)
82.00%
81.00%
80.00%
79.00%
78.00%
77.00%
76.00%
$4,460.00
$4,450.00
$4,440.00
$4,430.00
$4,420.00
$4,410.00
$4,400.00
$4,390.00
$4,380.00
$4,370.00
81.52%
81.37%
81.05%
80.16%
80.16%
80.16%
78.12%
78.04%
78.04%
-500MW to Zone F at F EFORd
Base Case
+500MW to Zone F at F EFORd
Optimize w/o TSL Cost (million $)
Optimize w/ TSL Cost (million $)
Current LCR Cost (million $)
Optimize w/o TSL Zone J LCR
Optimize w/ TSL Zone J LCR (Limit @ 80.16%)
Current LCR Zone J LCR



Addition and Removal of Capacity from Zone F
Zone K LCR
107.00%
106.00%
105.00%
104.00%
103.00%
102.00%
101.00%
Locational Capacity Requirement
$4,460.00
$4,450.00
$4,440.00
$4,430.00
$4,420.00
$4,410.00
$4,400.00
$4,390.00
$4,380.00
$4,370.00
Cost of Procurement (million $)
106.62%
105.27%
105.21%
104.70%
104.15%
104.34%
103.40%
103.25%
102.88%
-500MW to Zone F at F EFORd
Base Case
+500MW to Zone F at F EFORd
Optimize w/o TSL Cost (million $)
Optimize w/ TSL Cost (million $)
Current LCR Cost (million $)
Optimize w/o TSL Zone K LCR
Optimize w/ TSL Zone K LCR (Limit @ 102.99%)
Current LCR Zone K LCR

Addition and Removal of Capacity from Zone F G-J LCR

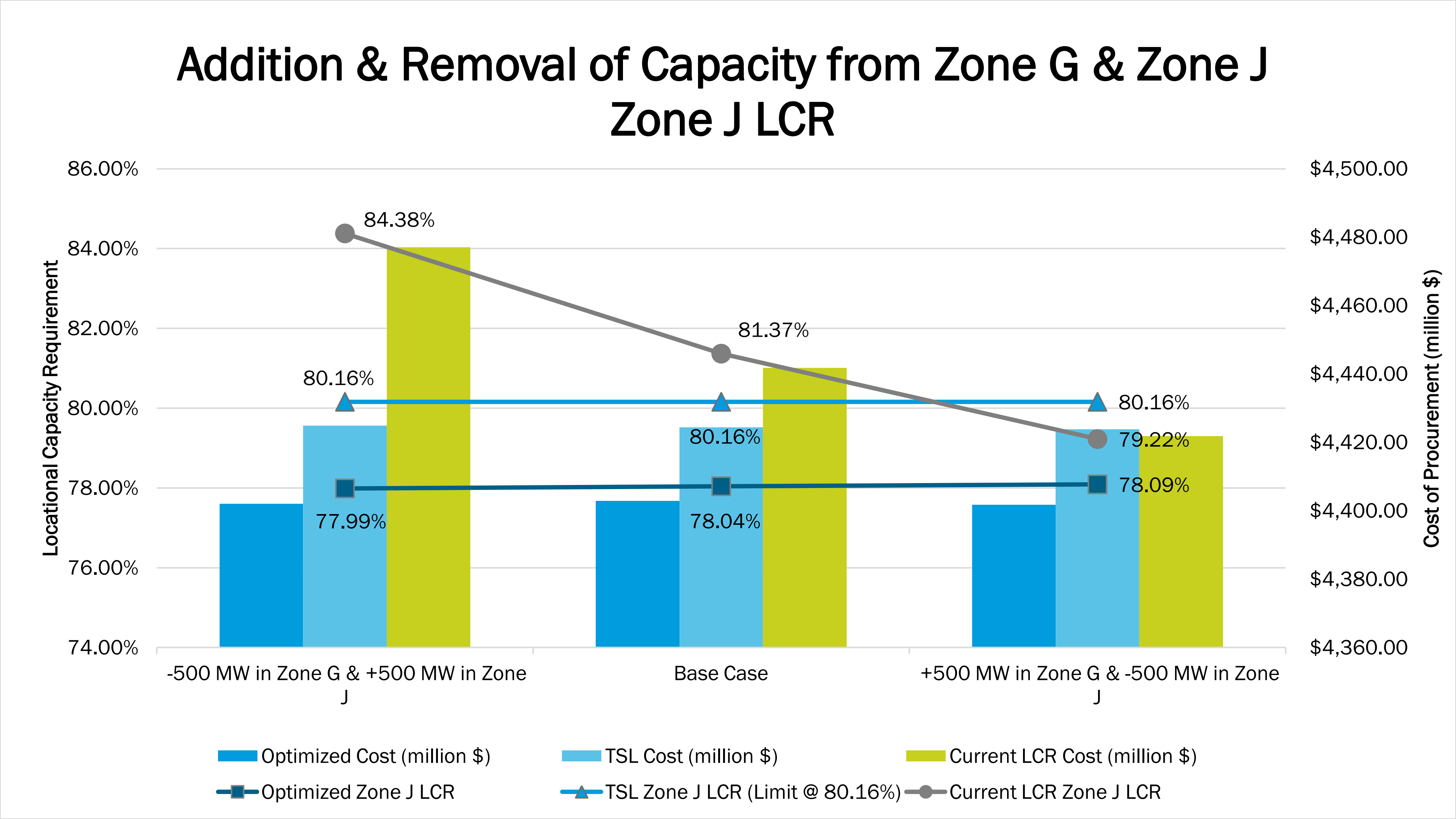


Multiple Changes in Generation

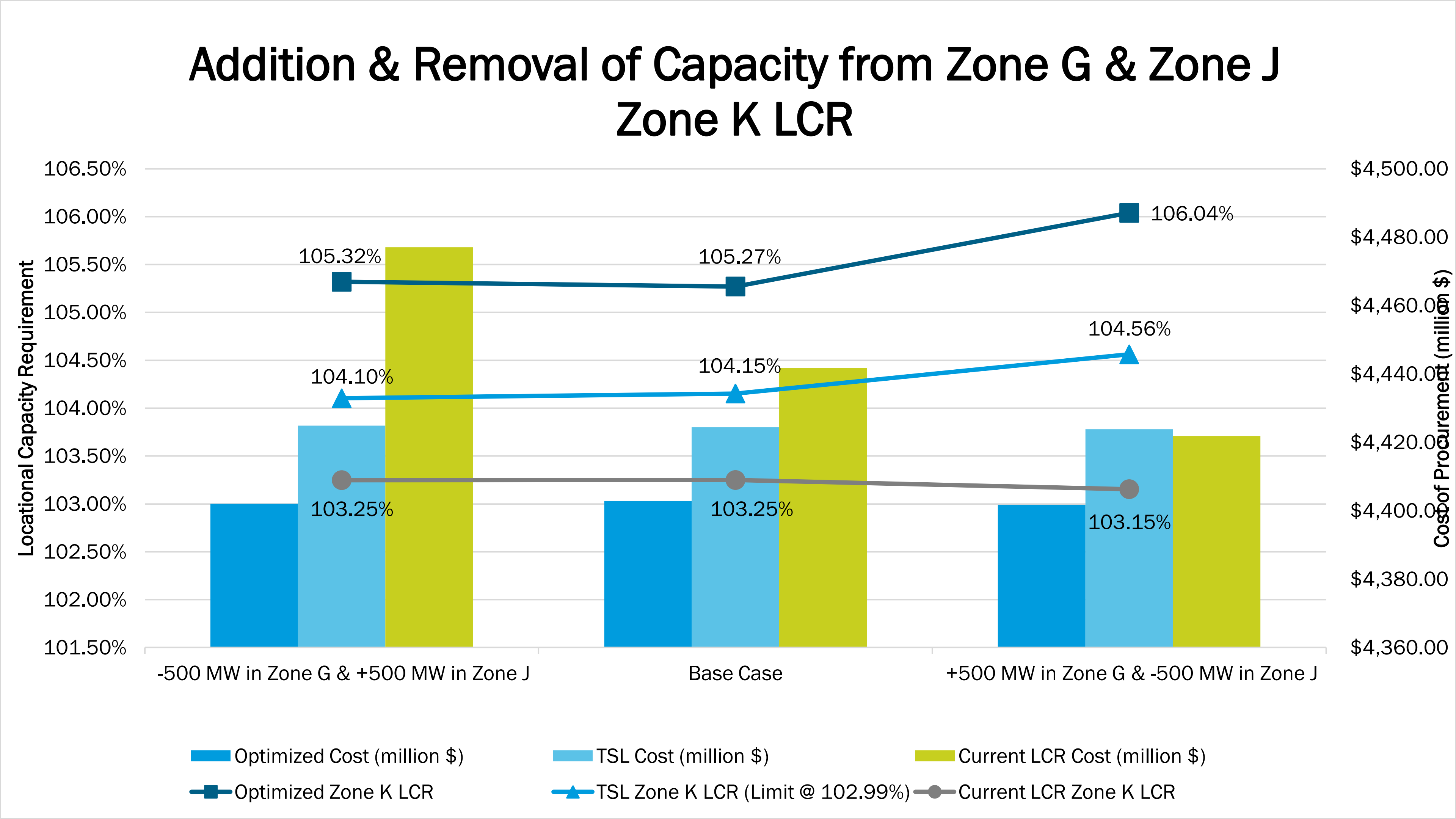
- +500 MW in Zone G & -500 MW in Zone J
- -500 MW in Zone G & +500 MW in Zone J
- +500 MW in Zone K & -500 MW in Zone J
- -500 MW in Zone K & +500 MW in Zone J

Market Simulations: +/- 500 MW to Zone G and +/-500 MW to Zone J

NEW YORK INDEPENDENT SYSTEM OPERATOR

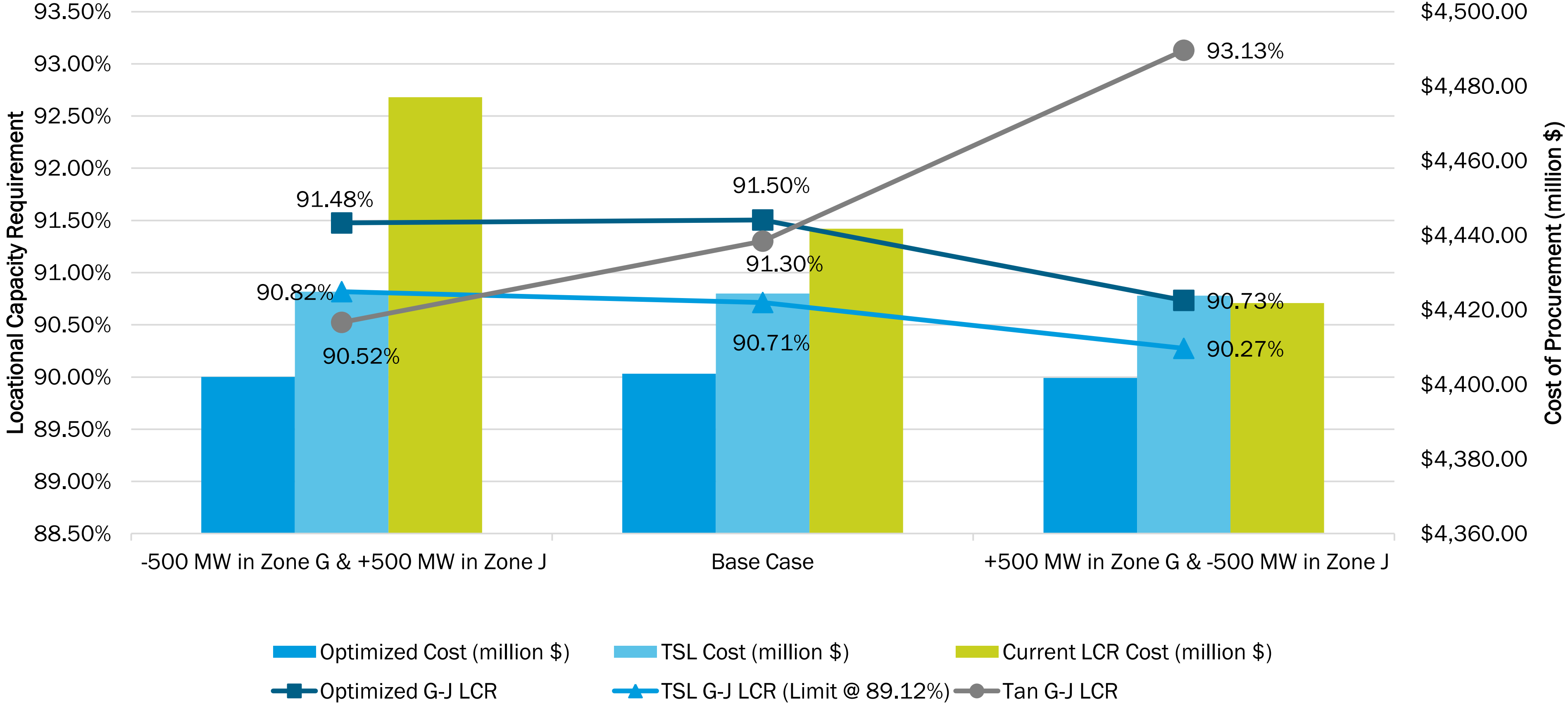


Addition & Removal of Capacity from Zone G & Zone J
Zone J LCR
86.00%
84.00%
82.00%
80.00%
78.00%
76.00%
74.00%
Locational Capacity Requirement
$4,500.00
$4,480.00
$4,460.00
$4,440.00
$4,420.00
$4,400.00
$4,380.00
$4,360.00
Cost of Procurement (million $)
84.38%
81.37%
80.16%
80.16%
80.16%
79.22%
78.09%
77.99%
78.04%
-500 MW in Zone G & +500 MW in Zone J
Base Case
+500 MW in Zone G & -500 MW in Zone J
Optimized Cost (million $)
TSL Cost (million $)
Current LCR Cost (million $)
Optimized Zone J LCR
TSL Zone J LCR (Limit @ 80.16%)
Current LCR Zone J LCR

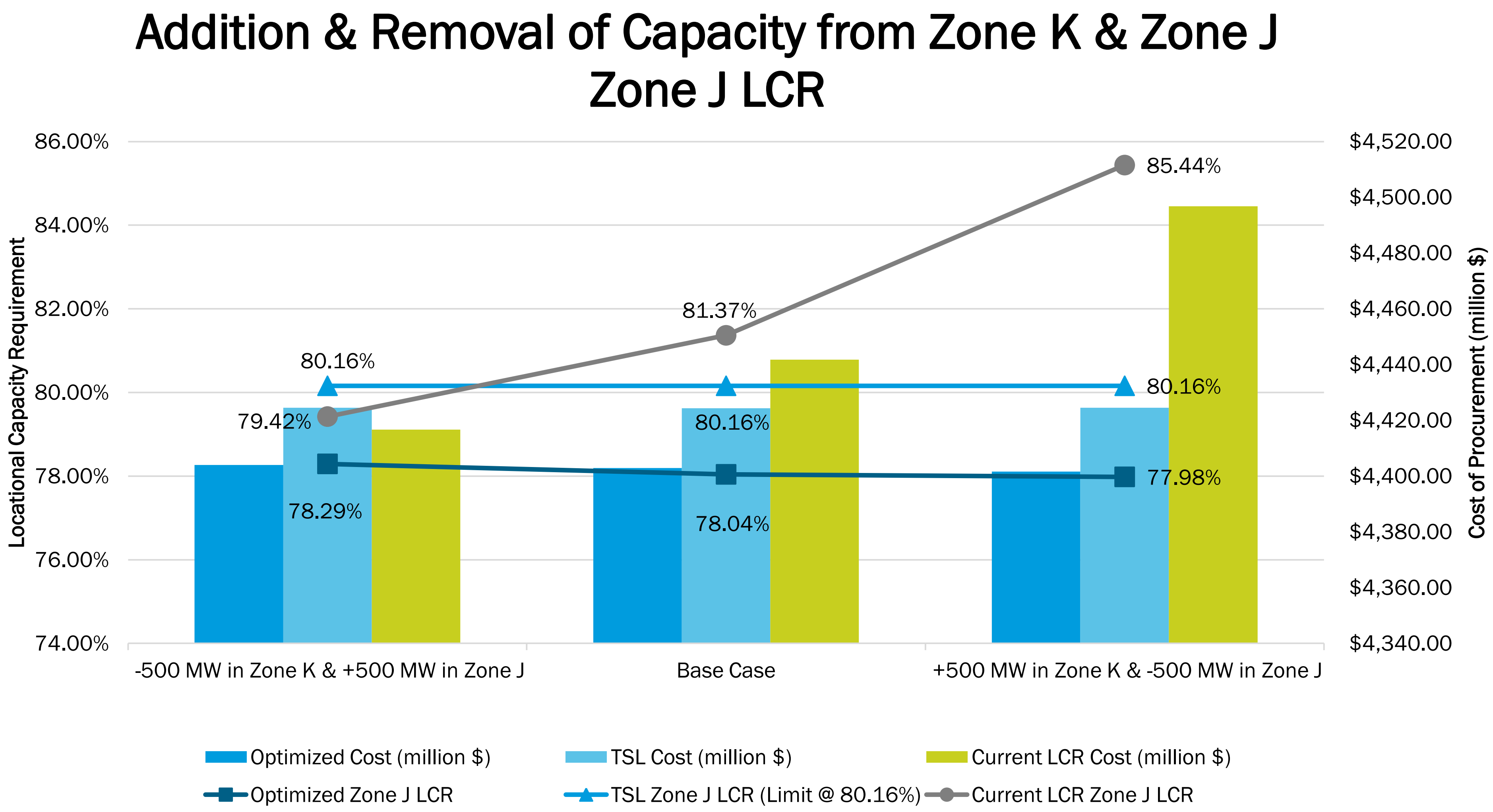


Addition & Removal of Capacity from Zone G & Zone J
Zone K LCR
Locational Capacity Requirement
Cost of Procurement (million $)
106.50%
106.00%
105.50%
105.00%
104.50%
104.00%
103.50%
103.00%
102.50%
102.00%
101.50%
$4,500.00
$4,480.00
$4,460.00
$4,440.00
$4,420.00
$4,400.00
$4,380.00
$4,360.00
105.32%
105.27%
106.04%
104.10%
104.15%
104.56%
103.25%
103.25%
103.15%
-500 MW in Zone G & +500 MW in Zone J
Base Case
+500 MW in Zone G & -500 MW in Zone J
Optimized Cost (million $)
TSL Cost (million $)
Current LCR Cost (million $)
Optimized Zone K LCR
TSL Zone K LCR (Limit @ 102.99%)
Current LCR Zone K LCR

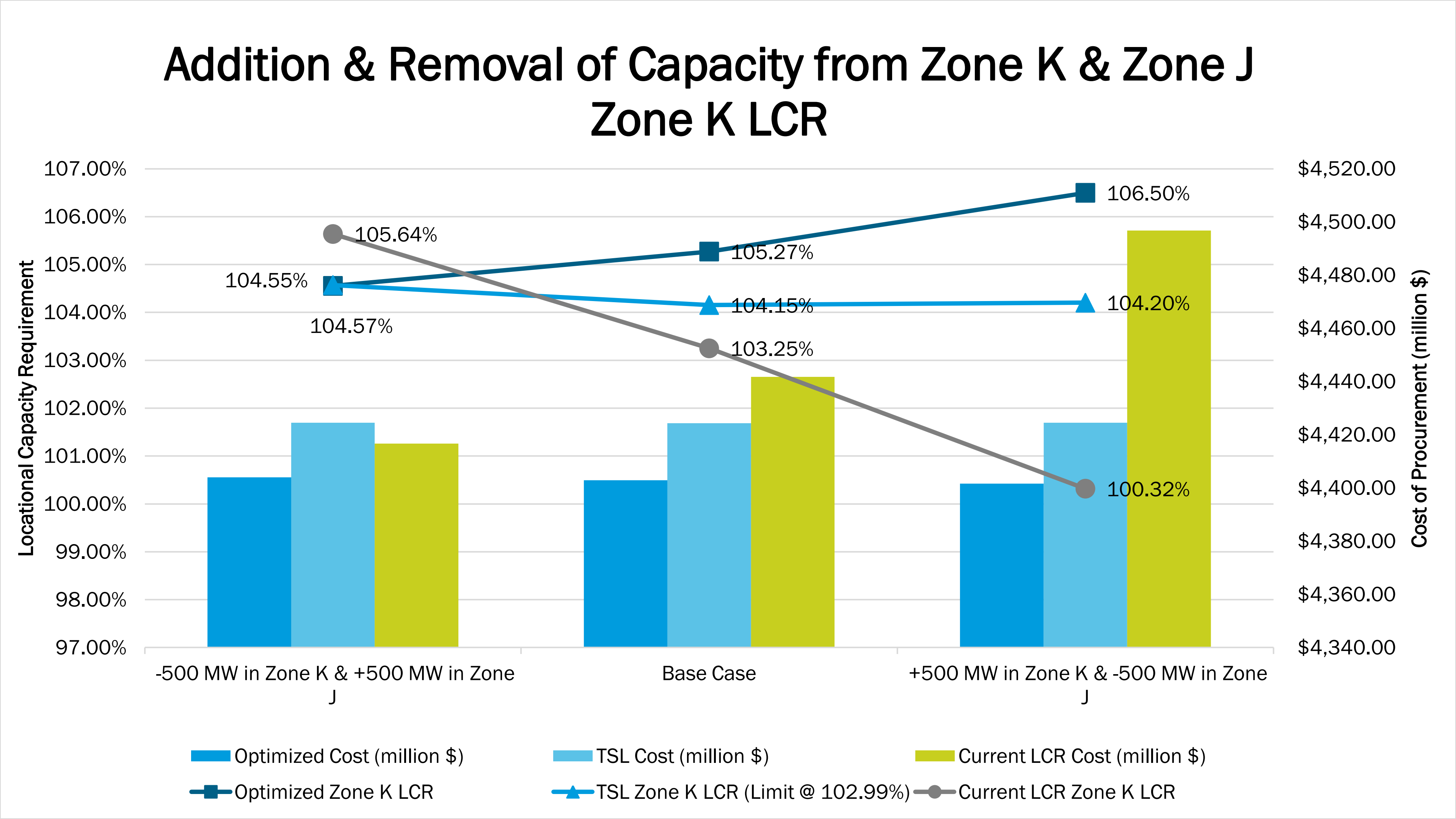
Addition & Removal of Capacity from Zone G & Zone J G-J LCR

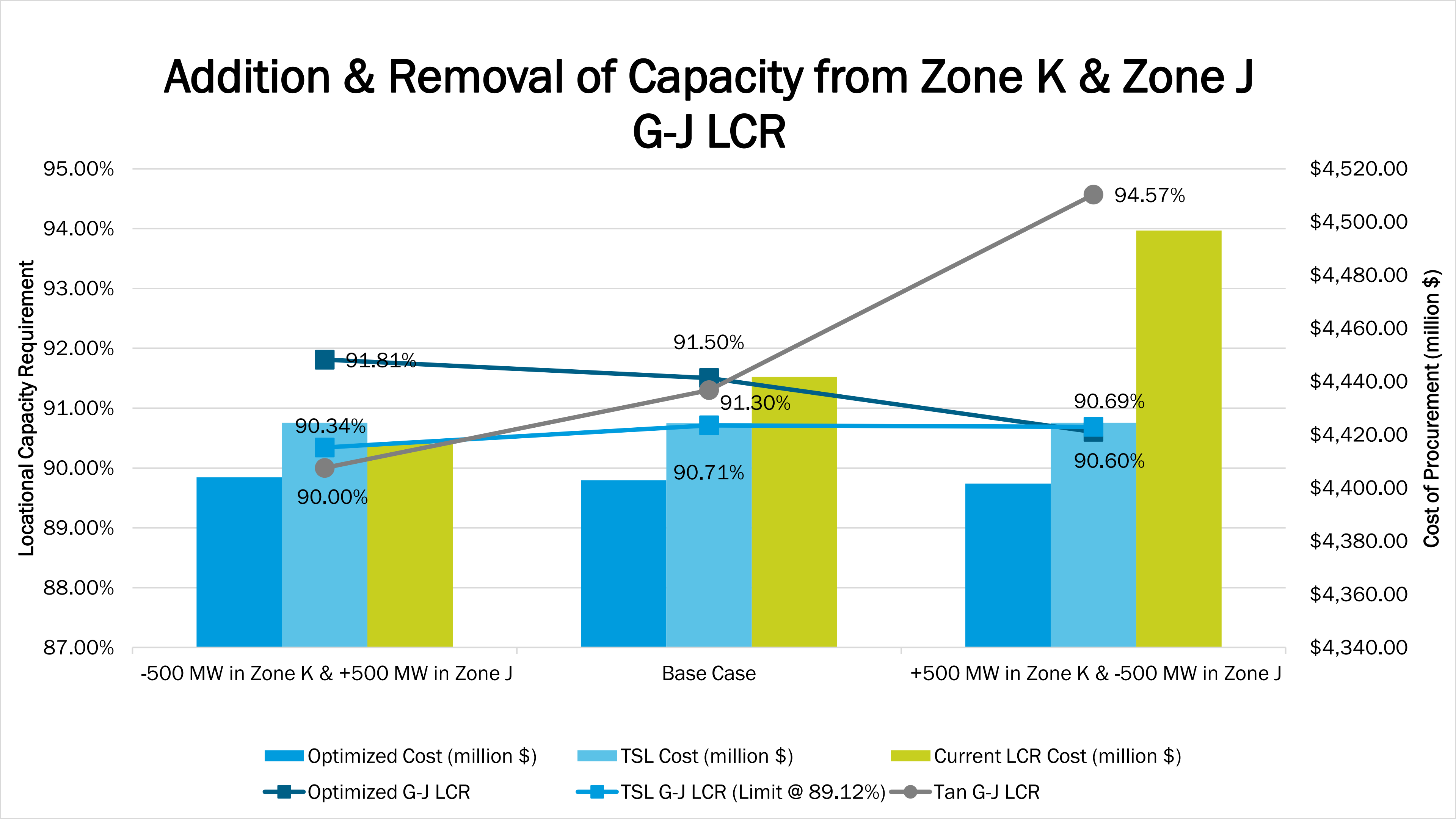


Market Simulations: +/- 500 MW to Zone K and +/-500 MW to Zone J



Addition & Removal of Capacity from Zone K & Zone J
Zone J LCR
Locational Capacity Requirement
Cost of Procurement (million $)
86.00%
84.00%
82.00%
80.00%
78.00%
76.00%
74.00%
$4,520.00
$4,500.00
$4,480.00
$4,460.00
$4,440.00
$4,420.00
$4,400.00
$4,380.00
$4,360.00
$4,340.00
85.44%
81.37%
80.16%
80.16%
80.16%
79.42%
78.29%
78.04%
77.98%
-500 MW in Zone K & +500 MW in Zone J
Base Case
+500 MW in Zone K & -500 MW in Zone J
Optimized Cost (million $)
TSL Cost (million $)
Current LCR Cost (million $)
Optimized Zone J LCR
TSL Zone J LCR (Limit @ 80.16%)
Current LCR Zone J LCR


Addition & Removal of Capacity from Zone K & Zone J
Zone K LCR
Locational Capacity Requirement
Cost of Procurement (million $)
107.00%
106.00%
105.00%
104.00%
103.00%
102.00%
101.00%
100.00%
99.00%
98.00%
97.00%
$4,520.00
$4,500.00
$4,480.00
$4,460.00
$4,440.00
$4,420.00
$4,400.00
$4,380.00
$4,360.00
$4,340.00
105.64%
104.55%
104.57%
105.27%
104.15%
103.25%
106.50%
104.20%
100.32%
-500 MW in Zone K & +500 MW in Zone J
Base Case
+500 MW in Zone K & -500 MW in Zone J
Optimized Cost (million $)
TSL Cost (million $)
Current LCR Cost (million $)
Optimized Zone K LCR
TSL Zone K LCR (Limit @ 102.99%)
Current LCR Zone K LCR



Addition & Removal of Capacity from Zone K & Zone J
G-J LCR
Locational Capacity Requirement
Cost of Procurement (million $)
95.00%
94.00%
93.00%
92.00%
91.00%
90.00%
89.00%
88.00%
87.00%
$4,520.00
$4,500.00
$4,480.00
$4,460.00
$4,440.00
$4,420.00
$4,400.00
$4,380.00
$4,360.00
$4,340.00
91.81%
90.34%
90.00%
91.50%
91.30%
90.71%
94.57%
90.69%
90.60%
-500 MW in Zone K & +500 MW in Zone J
Base Case
+500 MW in Zone K & -500 MW in Zone J
Optimized Cost (million $)
TSL Cost (million $)
Current LCR Cost (million $)
Optimized G-J LCR
TSL G-J LCR (Limit @ 89.12%)
Tan G-J LCR

Changes in Transmission

Changes in Transmission

- +1000 MW to UPNY-SENY
  - Transmission Security Limit for G-J was recalculated assuming an additional 1000 MW of import capability

+1000 MW to UPNY-SENY

Scenario	Zone J LCR	Zone K LCR	G-J LCR	Cost ($ million)
Current LCR Methodology	79.38%	101.94%	90.18%	$ 4,398.63
Optimized Methodology without Transmission Security Limits (TSL)	77.71%	107.44%	84.29%	$4,365.16
Optimized Methodology with Transmission Security Limits (TSL)	**80.16%**	**103.80%**	**84.96%**	**$4,388.00**

- **G-J import limit was increased by 1000 MW in the TSL calculation resulting in a reduction in the TSL from 89.12% to 82.17%**

+1000 MW to UPNY-SENY

Scenario	Zone J LCR	Zone K LCR	G-J LCR
Current LCR Methodology	9,263 MW	5,532 MW	14,484 MW
Optimized Methodology without Transmission Security Limits (TSL)	9,069 MW	5,831 MW	13,538 MW
Optimized Methodology with Transmission Security Limits (TSL)	9,355 MW	5,633 MW	13,645 MW

Change from Base Case to +1000 MW UPNY-SENY

Scenario	Δ Zone J MW	Δ Zone K MW	Δ G-J MW	Δ Total Locality MW
Current LCR Methodology	-232.2	-71.1	-180.5	-483.8
Optimized Methodology without Transmission Security Limits (TSL)	-38.5	117.7	-1159.1	-1079.9
Optimized Methodology with Transmission Security Limits (TSL)	0.0	-19.2	-924.8	-944.1

NEW YORK INDEPENDENT SYSTEM OPERATOR

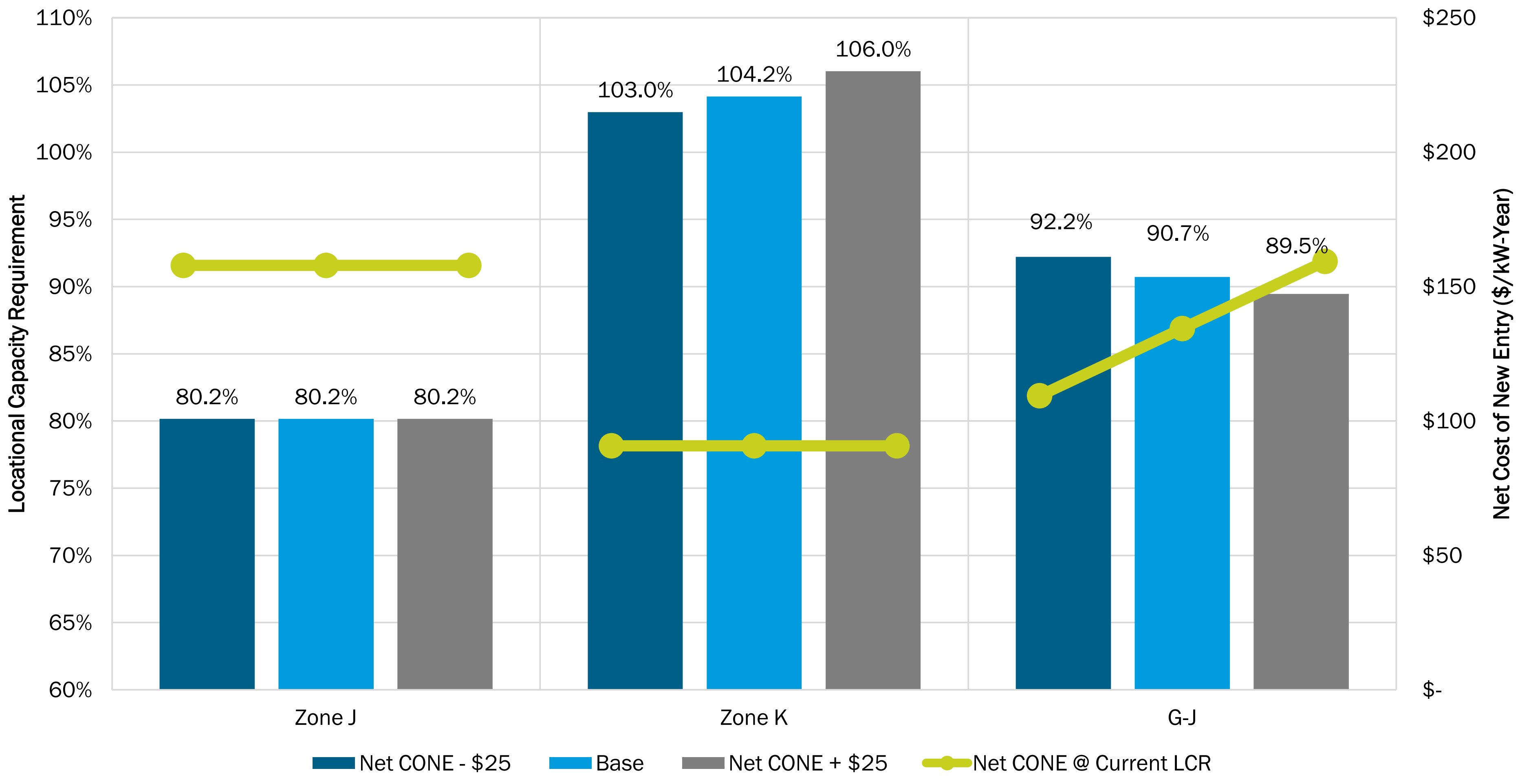
Changes in Net CONE

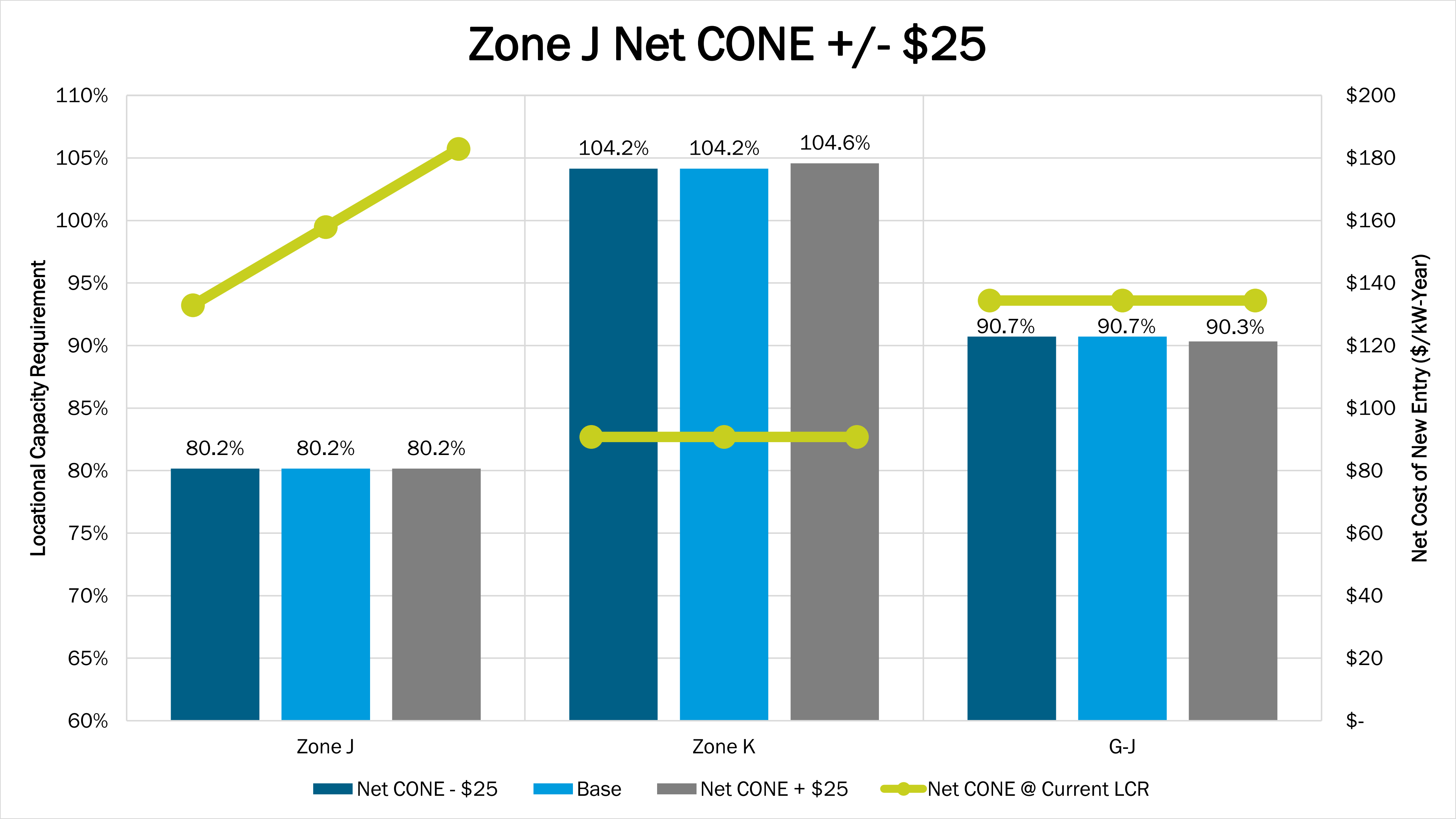
Changes in Net CONE

- +/- $25.00 to G-J Net CONE
- +/- $25.00 to Zone J Net CONE
- +/- $25.00 to Zone K Net CONE
- +/- $25.00 to NYCA Net CONE

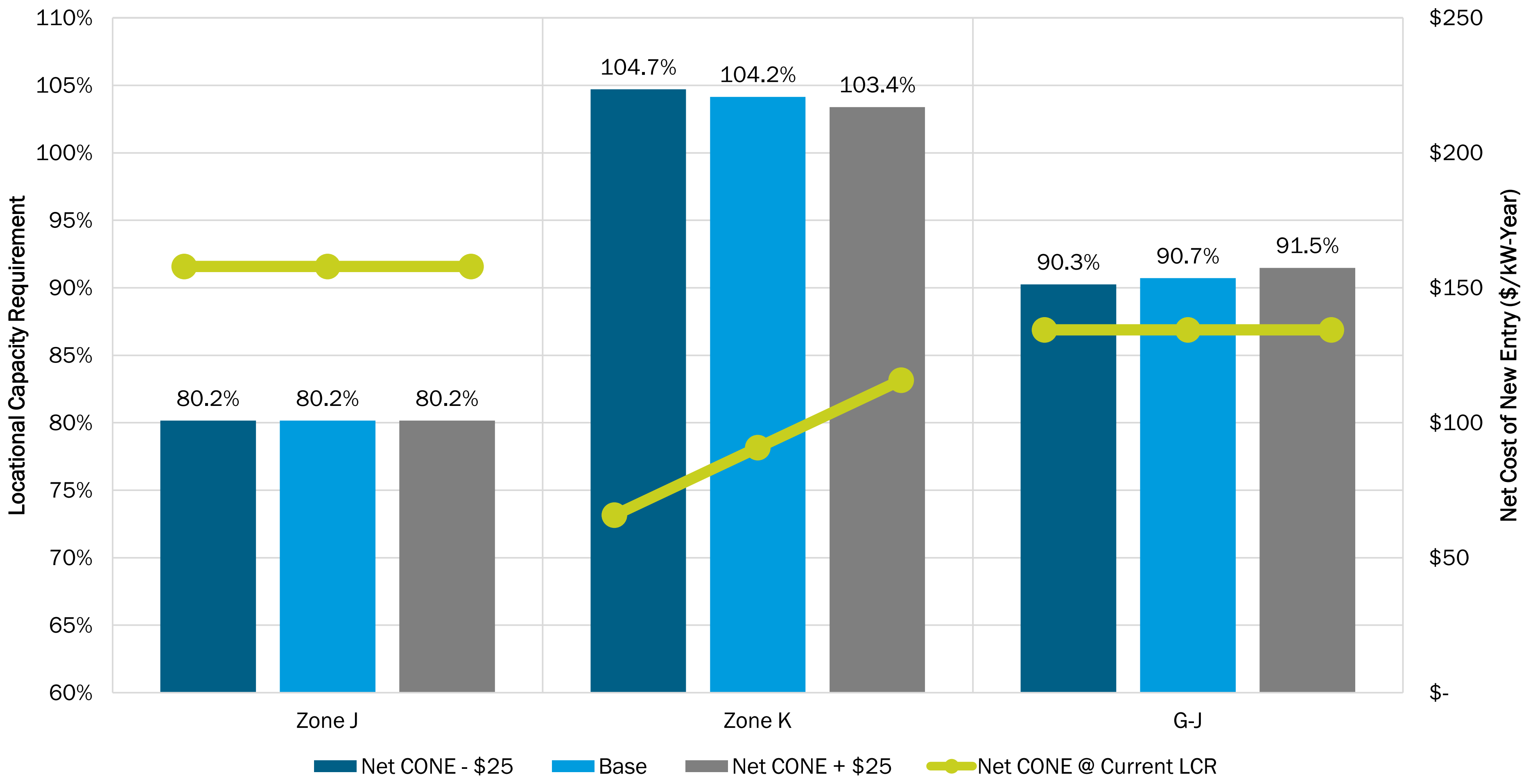
NEW YORK INDEPENDENT SYSTEM OPERATOR

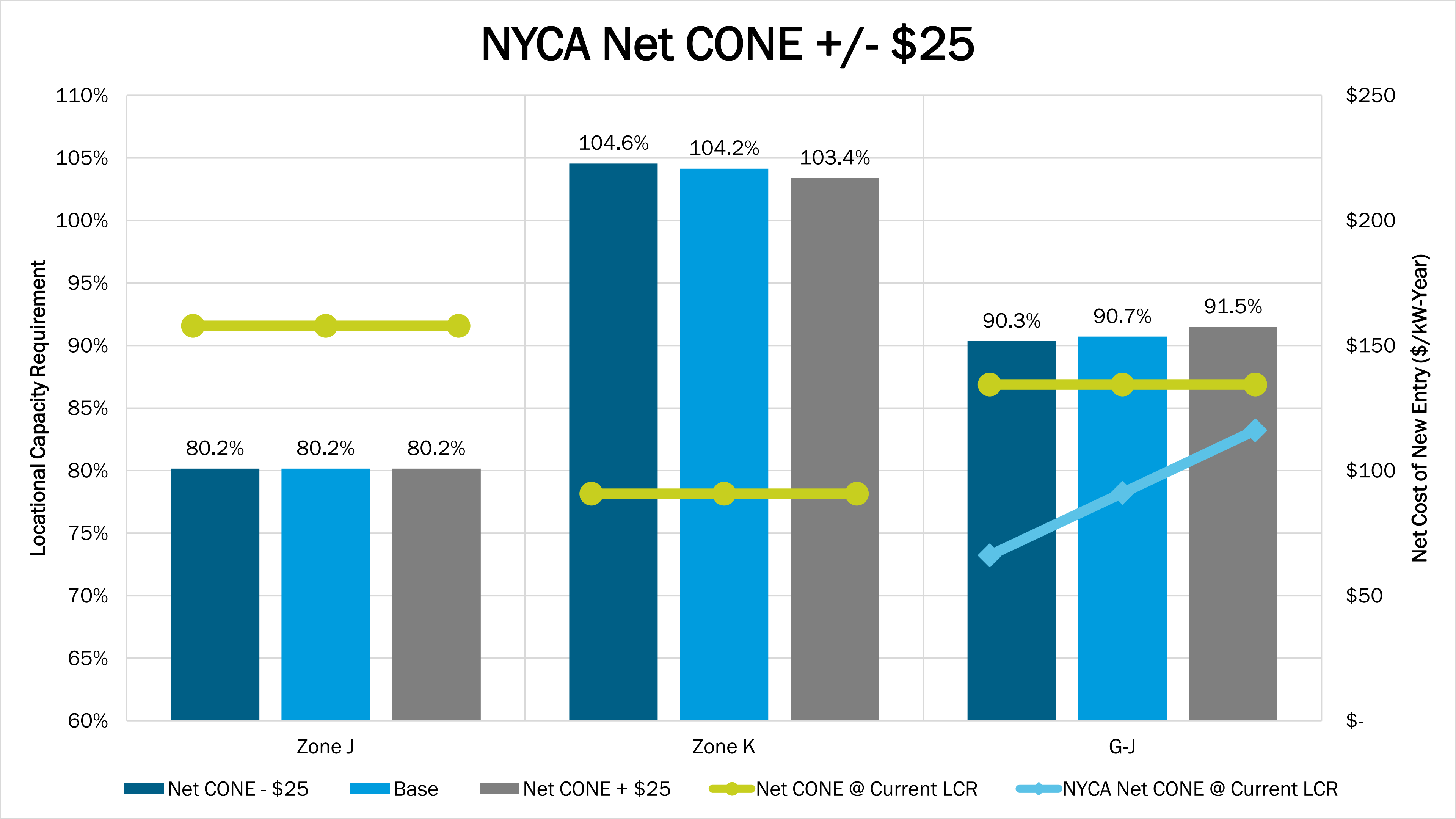
G-J Net CONE +/- $25




Zone J Net CONE +/- $25
110%
105%
100%
95%
90%
85%
80%
75%
70%
65%
60%
Locational Capacity Requirement
$200
$180
$160
$140
$120
$100
$80
$60
$40
$20
$-
Net Cost of New Entry ($/kW-Year)
80.2%
80.2%
80.2%
104.2%
104.2%
104.6%
90.7%
90.7%
90.3%
Zone J
Zone K
G-J
Net CONE - $25
Base
Net CONE + $25
Net CONE @ Current LCR

Zone K Net CONE +/- $25





NYCA Net CONE +/- $25
110%
105%
100%
95%
90%
85%
80%
75%
70%
65%
60%
Locational Capacity Requirement
$250
$200
$150
$100
$50
$-
Net Cost of New Entry ($/kW-Year)
80.2%
80.2%
80.2%
104.6%
104.2%
103.4%
90.3%
90.7%
91.5%
Zone J
Zone K
G-J
Net CONE - $25
Base
Net CONE + $25
Net CONE @ Current LCR
NYCA Net CONE @ Current LCR

All Sensitivities

Scenario	Optimized LCR without Transmission Security Floors (%)			Optimized Cost (million)
	Zone J	Zone K	G-J	
Base Case	78.04%	105.27%	91.50%	$ 4,402.89
+500 MW to Zone G at G-J EFORd	78.11%	105.97%	90.76%	$ 4,401.96
-500 MW to Zone G at G-J EFORd	78.06%	105.93%	90.78%	$ 4,400.95
+500MW to Zone J at J EFORd	78.04%	105.27%	91.50%	$ 4,402.89
-500MW to Zone J at J EFORd	78.04%	105.27%	91.50%	$ 4,402.89
+500MW to Zone K at K EFORd	78.29%	104.55%	91.81%	$ 4,404.03
-500MW to Zone K at K EFORd	78.05%	105.99%	90.81%	$ 4,401.55
+500MW to Zone F at F EFORd	78.04%	105.21%	91.01%	$ 4,397.54
-500MW to Zone F at F EFORd	78.12%	106.62%	90.96%	$ 4,408.19

Scenario	Optimized LCR without Transmission Security Floors (%)			Optimized Cost (million)
	Zone J	Zone K	G-J	
+1000 MW to UPNYSENY	77.71%	107.44%	84.29%	$4,365.16
+$25.00 to G-J	78.11%	106.76%	90.23%	$4,536.54
-$25.00 to G-J	77.57%	106.01%	91.76%	$4,260.14
+$25.00 Zone J	77.48%	107.46%	90.76%	$4,632.05
-$25.00 to Zone J	78.13%	104.90%	91.67%	$4,169.45
+$25.00 to Zone K	78.10%	104.55%	92.09%	$4,550.71
-$25.00 to Zone K	77.60%	107.18%	90.83%	$4,250.47
+$25.00 to NYCA	77.46%	106.73%	91.46%	$4,863.41
-$25.00 to NYCA	78.25%	105.62%	90.77%	$3,936.72

Scenario	Optimized LCR without Transmission Security Floors (%)			Optimized Cost (million)
	Zone J	Zone K	G-J	
+500 MW in Zone G at G-J EFORd & -500 MW in Zone J at J EFORd	78.09%	106.04%	90.73%	$4,401.78
+500 MW in Zone K at K EFORd & -500 MW in Zone J at J EFORd	78.29%	104.55%	91.81%	$4,404.03
-500 MW in Zone G at G-J EFORd & +500 MW in Zone J at J EFORd	77.99%	105.32%	91.48%	$4,402.07
-500 MW in Zone K at K EFORd & +500 MW in Zone J at J EFORd	77.98%	106.50%	90.60%	$4,401.59

Scenario	Optimized LCR with Preliminary Transmission Security Floors (%)			Optimized Cost (million)
	Zone J	Zone K	G-J	
Base Case	80.16%	104.15%	90.71%	$4,424.37
+500 MW to Zone G at G-J EFORd	80.16%	104.56%	90.27%	$4,423.79
-500 MW to Zone G at G-J EFORd	80.16%	104.52%	90.40%	$4,424.65
+500MW to Zone J at J EFORd	80.16%	104.15%	90.71%	$4,424.37
-500MW to Zone J at J EFORd	80.16%	104.15%	90.71%	$4,424.37
+500MW to Zone K at K EFORd	80.16%	104.57%	90.34%	$4,424.52
-500MW to Zone K at K EFORd	80.16%	104.20%	90.69%	$4,424.55
+500MW to Zone F at F EFORd	80.16%	104.34%	90.17%	$4,420.83
-500MW to Zone F at F EFORd	80.16%	104.70%	90.81%	$4,430.07

Scenario	Optimized LCR with Preliminary Transmission Security Floors (%)			Optimized Cost (million)
	Zone J	Zone K	G-J	
+1000 MW to UPNYSENY	80.16%	103.80%	84.96%	$4,388.00
+$25.00 to G-J	80.16%	106.03%	89.45%	$4,553.59
-$25.00 to G-J	80.16%	102.99%	92.22%	$4,292.37
+$25.00 Zone J	80.16%	104.57%	90.34%	$4,663.81
-$25.00 to Zone J	80.16%	104.15%	90.71%	$4,185.05
+$25.00 to Zone K	80.16%	103.39%	91.48%	$4,570.88
-$25.00 to Zone K	80.16%	104.70%	90.26%	$4,277.37
+$25.00 to NYCA	80.16%	103.40%	91.50%	$4,890.94
-$25.00 to NYCA	80.16%	104.56%	90.35%	$3,955.84

Scenario	Optimized LCR with Preliminary Transmission Security Floors (%)			Optimized Cost (million)
	Zone J	Zone K	G-J	
+500 MW in Zone G at G-J EFORd & -500 MW in Zone J at J EFORd	80.16%	104.56%	90.27%	$4,423.79
+500 MW in Zone K at K EFORd & -500 MW in Zone J at J EFORd	80.16%	104.57%	90.34%	$4,424.52
-500 MW in Zone G at G-J EFORd & +500 MW in Zone J at J EFORd	80.16%	104.10%	90.82%	$4,424.92
-500 MW in Zone K at K EFORd & +500 MW in Zone J at J EFORd	80.16%	104.20%	90.69%	$4,424.55

NEW YORK INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY

Scenario	Current LCR Methodology (%)			Optimized Cost (million)
	Zone J	Zone K	G-J	
Base Case	81.4%	103.2%	91.3%	$ 4,441.80
+500 MW to Zone G at G-J EFORd	79.87%	102.37%	93.44%	$ 4,429.79
-500 MW to Zone G at G-J EFORd	83.52%	104.21%	89.86%	$ 4,470.71
+500MW to Zone J at J EFORd	81.94%	102.48%	91.94%	$ 4,450.11
-500MW to Zone J at J EFORd	80.38%	104.10%	90.73%	$ 4,428.17
+500MW to Zone K at K EFORd	80.14%	104.48%	90.46%	$ 4,424.31
-500MW to Zone K at K EFORd	84.43%	100.67%	93.78%	$ 4,482.72
+500MW to Zone F at F EFORd	81.05%	102.88%	91.26%	$ 4,433.26
-500MW to Zone F at F EFORd	81.52%	103.40%	91.60%	$ 4,448.38

Scenario	Current LCR Methodology (%)			Optimized Cost (million)
	Zone J	Zone K	G-J	
+1000 MW to UPNYSENY	79.38%	101.94%	90.18%	$ 4,398.63
+500 MW in Zone G at G-J EFORd & -500 MW in Zone J at J EFORd	79.22%	103.15%	93.13%	$ 4,421.80
+500 MW in Zone K at K EFORd & -500 MW in Zone J at J EFORd	79.42%	105.64%	90.00%	$ 4,416.64
-500 MW in Zone G at G-J EFORd & +500 MW in Zone J at J EFORd	84.38%	103.25%	90.52%	$ 4,477.06
-500 MW in Zone K at K EFORd & +500 MW in Zone J at J EFORd	85.44%	100.32%	94.57%	$ 4,496.80

NEW YORK INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY

Exhibit 28

Alternative Methods for Determining LCRs

Zachary Stines
Associate Market Design Specialist

Installed Capacity Working Group

October 30, 2017, NYISO

May 11, 2017 – REVISED October 27, 2017 , NYISO

THIS PPT UPDATES THE PPT POSTED FOR THE Oct. 30, ICAPWG MEETING. The updates are to:

- Column labels on Slide 31

NEW YORK INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY

Agenda

- **Transmission Security**
  - N-1-1 Assumptions
  - Stability of Import Limits
  - Timeline of Assumptions
  - Final Results
- **Sensitivity Results**
  - Multiple Changes in Generation
  - Changes in Transmission
  - Net CONE
- **Next Steps**
- **Questions**

Transmission Security Limits (TSL)

Overview of Preliminary Analysis

- Analyzed the N-1-1 thermal transfer limits for the NYCA interfaces associated with the G-J, Zone J, and Zone K Localities
- Used the final Summer 2017 Operating base case
  - Rebuilt case to conduct the N-1-1 analysis

Transmission Security Methodology

- N-1-1 analysis was conducted to determine the transmission security import limits into each Locality
- These import limits were used to determine the minimum available capacity required for each Locality
- To translate this minimum available capacity into a market requirement the methodology needs to account for capacity unavailability
- To account for capacity unavailability, the 5-year zonal EFORd was used to calculate minimum locational capacity requirements

Example Calculation

Transmission Security Requirements	Formula	Zone X
Load Forecast (MW)	[A] = Given	12,000
Transmission Security Import Limit (MW)	[B] = Given	1,500
Transmission Security UCAP Requirement (MW)	[C] = [A]-[B]	10,500
Transmission Security UCAP Requirement (%)	[D] = [C]/[A]	87.5%
5 Year EFORd (%)	[E] = Given	8.0%
Transmission Security ICAP Requirement (MW)	[F] = [C]/(1-[E])	11,413
Transmission Security LCR Floor (%)	[G] = [F]/[A]	**95.1%**

N-1-1 Analysis Assumptions

N-1-1 Base Case

- Updated Summer 2017 Operating base case
  - Inclusion of transmission and generation facility additions and retirements
- All system elements modeled as in service
- All generation represented

Boundary Assumptions

- The analysis calculates the N-1-1 transmission security import limits using the NYCA bulk power transmission facilities (BPTF) into each Locality
  - Zone J: Dunwoodie South interface
  - Zone K: ConEd-LIPA interface
  - G-J: UPNY-SENY interface
- The external transmission facilities are not incorporated in the analysis since
  - Facilities without UDRs cannot meet the Locality capacity requirements
  - Facilities with UDRs are treated as supply side resources

NEW YORK INDEPENDENT SYSTEM OPERATOR

Boundary Assumptions

- The import capability from Zone K was included within the Dunwoodie South definition as a result of a contractual agreement
- It was not included in the UPNY-SENY definition since the contractual agreement results in a net zero effect

UPNY-SENY

Name	Line ID	Voltage (kV)
Mohawk (Zone E) – Hudson Valley (Zone G)		
Coopers Corners-Middletown*	CCRT34	345
Coopers Corners-Dolson Ave*	CCDA42	345
West Woodbourne 115/69	T152	115/69
Capital (Zone F) – Hudson Valley (Zone G)		
Athens-Pleasant Valley*	91	345
Leeds-Pleasant Valley*	92	345
*Leeds-Hurley Ave.	301	345
Hudson-Pleasant Valley*	12	115
Blue Stores E-Pleasant Valley*	13-987	115
Blue Stores W-Pleasant Valley*	8	115
*Feura Bush-North Catskill	2	115

* Indicates the metered end of the circuit

NEW YORK INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY

Dunwoodie South

Name	Line ID	Voltage (kV)
Dunwoodie (Zone I) – NYC (Zone J)		
*Dunwoodie-Mott Haven	71	345
*Dunwoodie-Mott Haven	72	345
Sprain Brook-Tremont*	X28	345
*Sprain Brook-West 49th Street	M51	345
*Sprain Brook-West 49th Street	M52	345
*Sprain Brook-Academy	M29	345
*Dunwoodie-Sherman Creek	99031	138
*Dunwoodie-Sherman Creek	99032	138
*Dunwoodie-East 179th Street	99153	138
Long Island (Zone K) – NYC (Zone J)		
*Lake Success-Jamaica	903	138
*Valley Stream-Jamaica	901L_M	138

* Indicates the metered end of the circuit

NEW YORK INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY

ConEd – LIPA

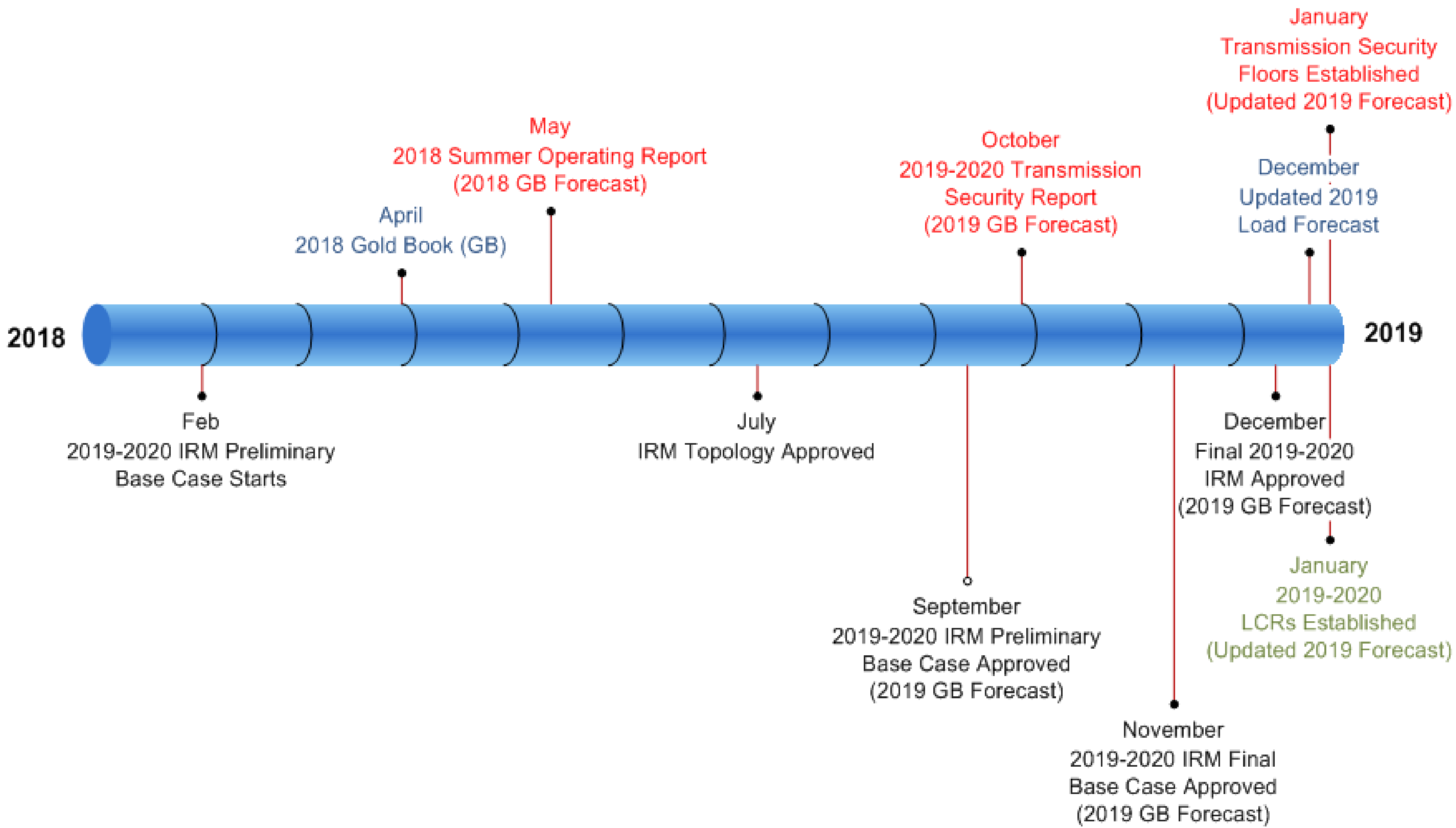
Name	Line ID	Voltage (kV)
Dunwoodie (Zone I) – Long Island (Zone K)		
*Dunwoodie-Shore Road	Y50	345
*Sprain Brook-East Garden City	Y49	345
NYC (Zone J) – Long Island (Zone K)		
Jamaica-Valley Stream*	901L_M	138
Jamaica-Lake Success*	903	138

* Indicates the metered end of the circuit

Load Forecast

- Summer Operating Report utilizes the Gold Book load forecast for the appropriate year
- The Transmission Security Limit analysis will use an updated load forecast -- the subsequent year's load forecast
  - This will result in a base case that utilizes the same load forecast assumed in the NYSRC IRM study

NEW YORK INDEPENDENT SYSTEM OPERATOR


2018
2019
Feb
2019-2020 IRM Preliminary
Base Case Starts
April
2018 Gold Book (GB)
May
2018 Summer Operating Report
(2018 GB Forecast)
July
IRM Topology Approved
September
2019-2020 IRM Preliminary
Base Case Approved
(2019 GB Forecast)
October
2019-2020 Transmission
Security Report
(2019 GB Forecast)
November
2019-2020 IRM Final
Base Case Approved
(2019 GB Forecast)
December
Updated 2019
Load Forecast
December
Final 2019-2020
IRM Approved
(2019 GB Forecast)
January
Transmission Security
Floors Established
(Updated 2019 Forecast)
January
2019-2020
LCRs Established
(Updated 2019 Forecast)

Example: 2018-2019 TSL Analysis

- **May 2017**
  - 2017 Summer Operating Report base case
    - Utilize the 2017 Gold Book load forecast (produced in April 2017)
- **Sept. 2017**
  - Perform the N-1-1 analysis to determine import capabilities into each Locality
    - Update the load forecast in the base case to be the 2018 Gold Book forecast (this is the same load forecast in NYSRC 2018-2019 IRM study)
    - Update expected generation and transmission changes consistent with NYSRC 2018-2019 IRM study
- **Jan. 2018**
  - Calculate TSLs
    - 2018 load forecast produced in December 2017
    - Import capabilities produced in October 2017
    - 5 year EFORd used in NYSRC 2018-2019 IRM study
  - Establish LCRs using optimization methodology
    - 2018 load forecast produced in December 2017
    - TSLs produced in January 2018

Line Rating Assumptions

- The G-J Locality and Zone K were calculated assuming Long Term Emergency (LTE) ratings
  - Consistent with NYISO Normal Operating and planning criteria
- Zone J was calculated assuming Normal line ratings
  - Based on NYSRC Local Reliability Rule (G1)

NEW YORK INDEPENDENT SYSTEM OPERATOR

Treatment of UDRs

- UDRs are treated as supply-side resources and at a level consistent with their elections
- UDRs are not considered as part of the import capability when calculating the N-1-1 import limits

Outage and Contingency

- In the N-1-1 analysis
  - 1st
    - Outage of the most limiting single element
  - 2nd
    - Zone K and G-J: NPCC defined contingency
    - Zone J: Outage of the second most limiting single element[1]

[1] Based on NYSRC Local Reliability Rules (*i.e.* G1)

Zone J

Outage Applied		Thermal Transfer
Sprain Brook – W. 49th St. (M51) 345 kV Sprain Brook – W. 49th St. (M52) 345 kV		3200 MW (1)
Limiting Element	**Rating**	**Limiting Contingency**
(1) Dunwoodie – Mott Haven (71) 345 kV	@NORM 785 MVA	Pre-Contingency Loading

DRAFT – FOR DISCUSSION PURPOSES ONLY

Zone K

Outage Applied		Thermal Transfer
Sprain Brook – East Garden City (Y49) 345 kV		350 MW (1)
Limiting Element	**Rating**	**Limiting Contingency**
(1) Dunwoodie – Shore Rd. (Y50) 345 kV	@NORM 687 MVA[2]	Pre-Contingency Loading

[2] LIPA rating for Y50 circuit is based on 70 % loss factor and rapid oil circulation.

G-J

Outage Applied		Thermal Transfer
Athens – Pleasant Valley (91) 345 kV		3225 MW (1)
Limiting Element	**Rating**	**Limiting Contingency**
(1) Leeds – Pleasant Valley (92) 345 kV	@LTE 1538 MVA L/O	Leeds – Hurly Ave. (301) 345 kV

DRAFT – FOR DISCUSSION PURPOSES ONLY

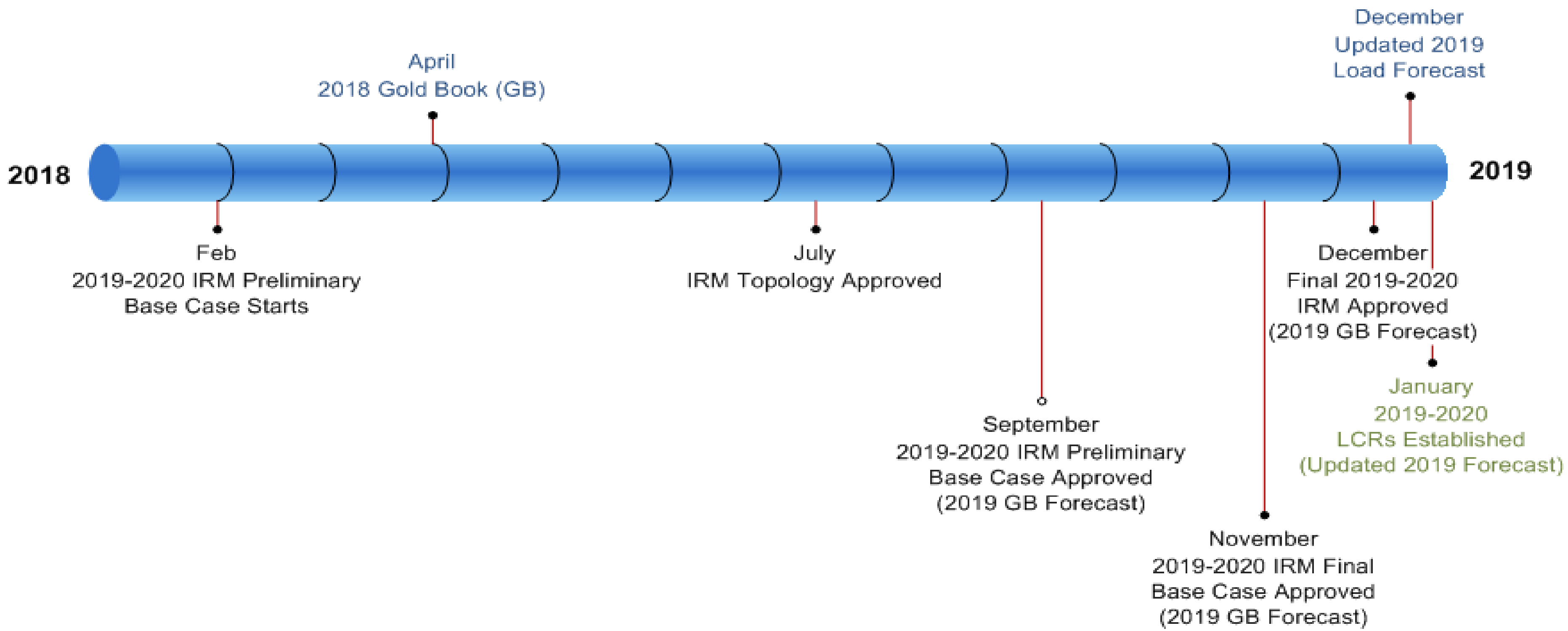
Stability of Transmission Security Limits

Stability with Changes in Generation

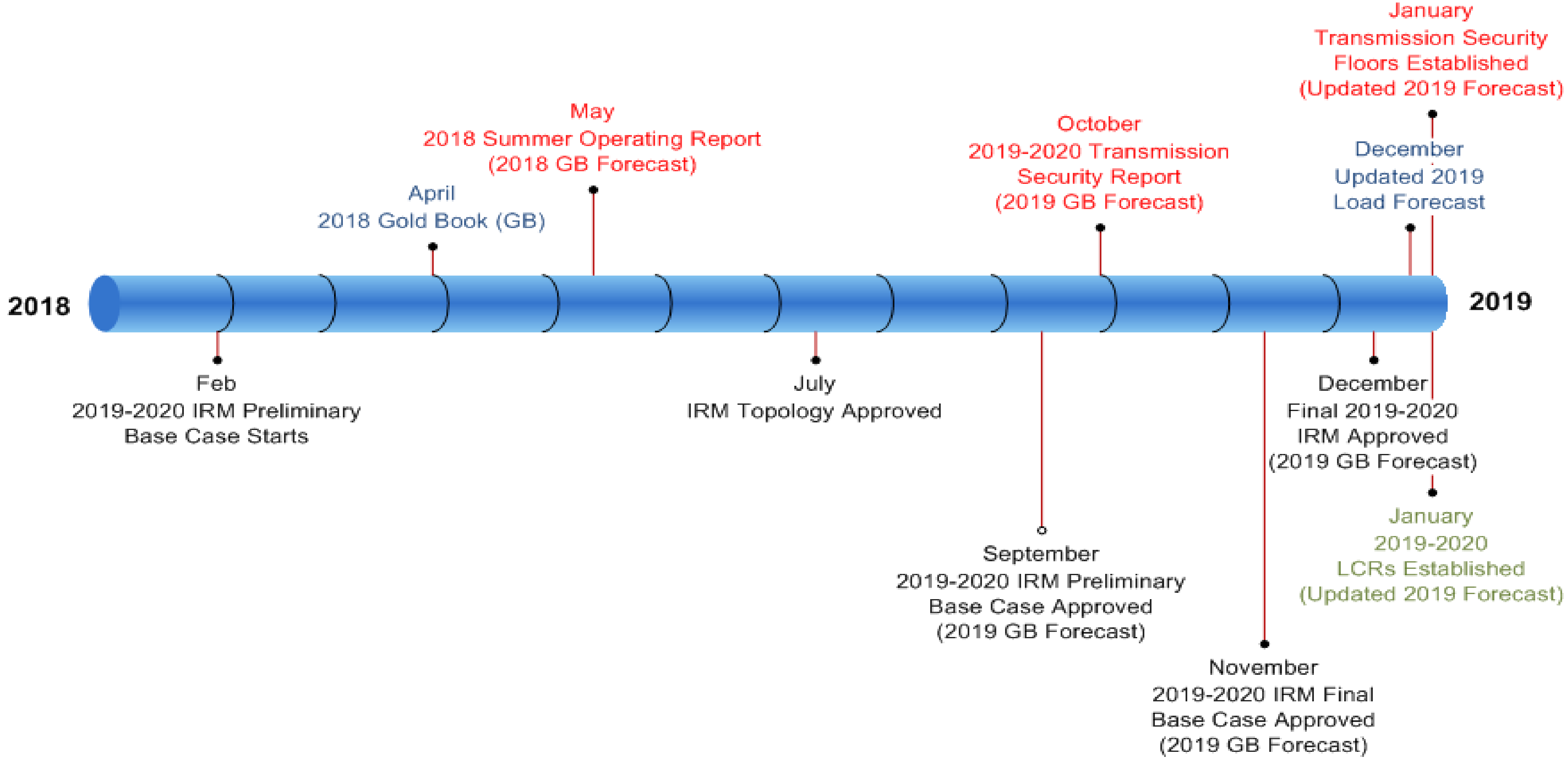
- The N-1-1 import limits used in the Transmission Security Limit (TSL) calculation are primarily impacted by changes in transmission
- Generation does not typically have an impact on the N-1-1 import limits
- Generation that impacts the distribution of flows on the interface facilities can have a impact on the N-1-1 import limits

Timeline of Assumptions

Current Timeline



Timeline Additions



LCR Setting Timeline

- No alterations to the current timeline are needed to accommodate this proposed alternative methodology for determining LCRs
- Transmission security analysis used in the alternative methodology would be conducted and reported prior to October 1st
    - This analysis would utilize an updated base case used in the Summer Operating Report

Final Results

Transmission Security LCR Floors

Transmission Security Requirements	G-J	Zone J	Zone K
Load Forecast (MW)	16,061	11,670	5,427
Transmission Security Import Limit (MW)	3,225	3200	350
Transmission Security UCAP Requirement (MW)	12,836	8,470	5,077
Transmission Security UCAP Requirement (%)	79.92%	72.58%	93.55%
5 Year EFORd (%)	10.50%	9.99%	10.06%
Transmission Security ICAP Requirement (MW)	14,342	9,410	5,645
Transmission Security LCR Floor (%)	**89.30%**	**80.63%**	**104.01%**

Transmission Security LCR Floors

	~~Zone J~~ G-J LCR	~~G-J~~ Zone J LCR	Zone KLCR
Transmission Security LCR Floors	**89.30%**	**80.63%**	**104.01%**

- These values are for the 2016-2017 capability year

Sensitivity Results

Multiple Changes in Generation

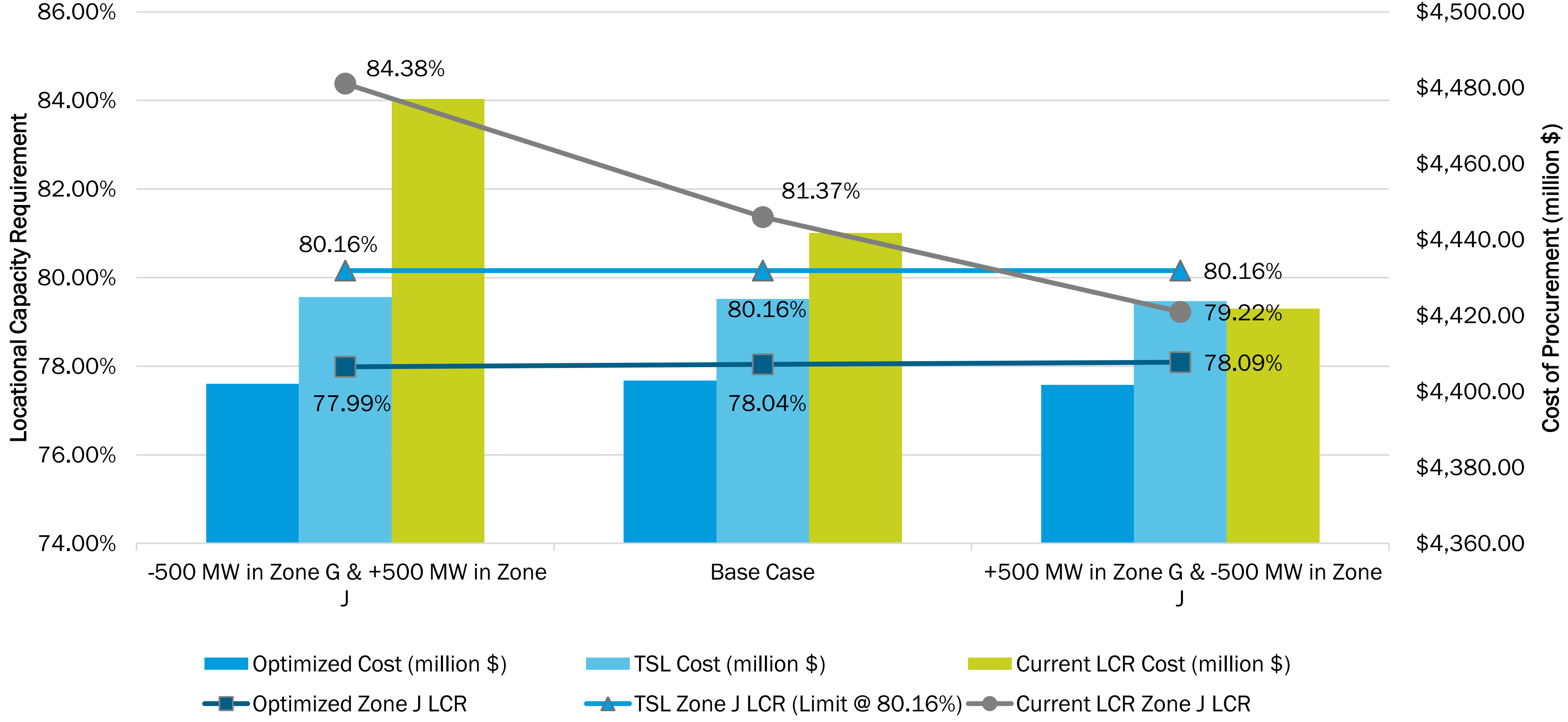
- +500 MW in Zone G & -500 MW in Zone J
- -500 MW in Zone G & +500 MW in Zone J
- +500 MW in Zone K & -500 MW in Zone J
- -500 MW in Zone K & +500 MW in Zone J

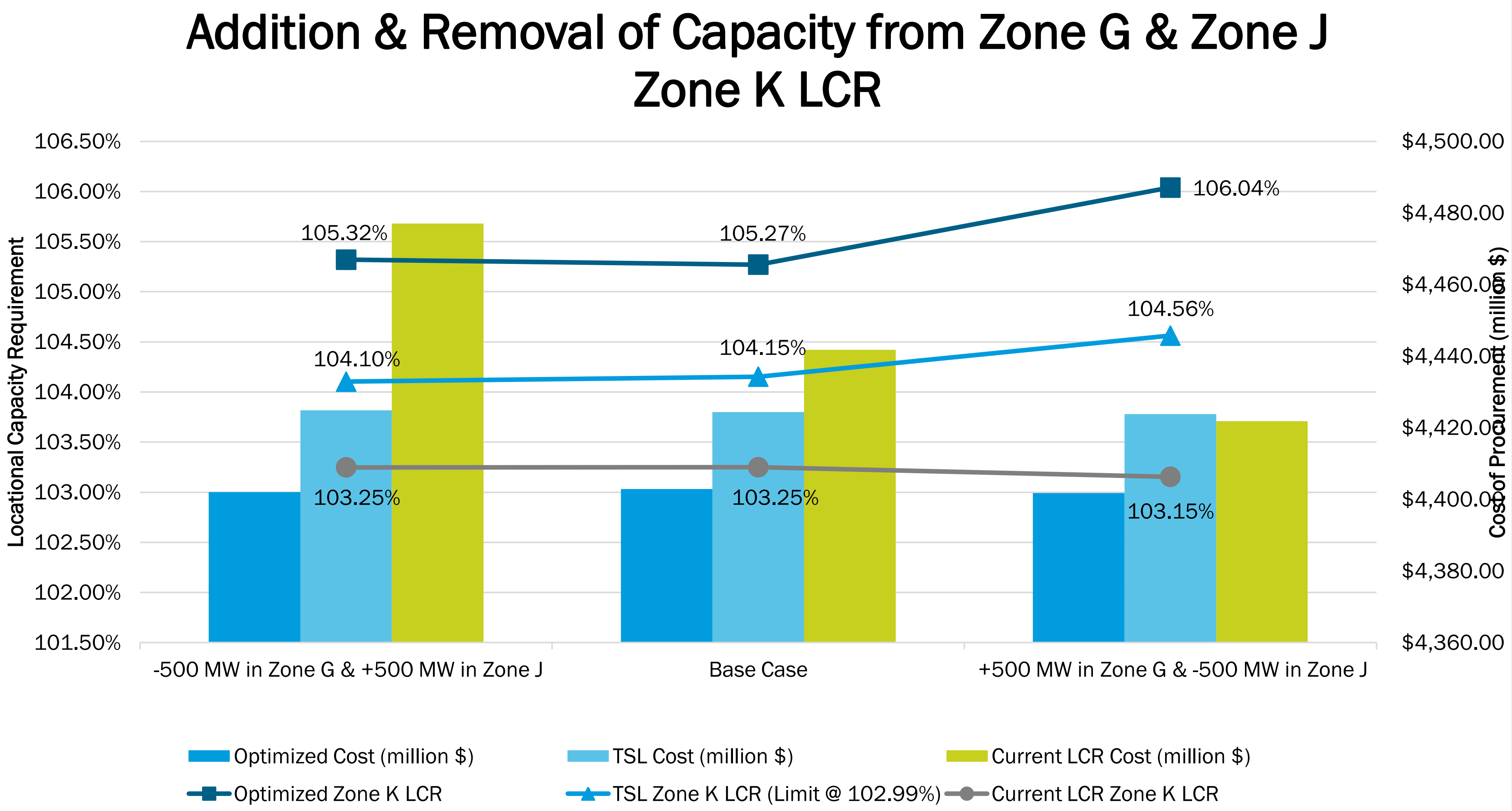
Market Simulations: +/- 500 MW to Zone G and +/-500 MW to Zone J

NEW YORK INDEPENDENT SYSTEM OPERATOR

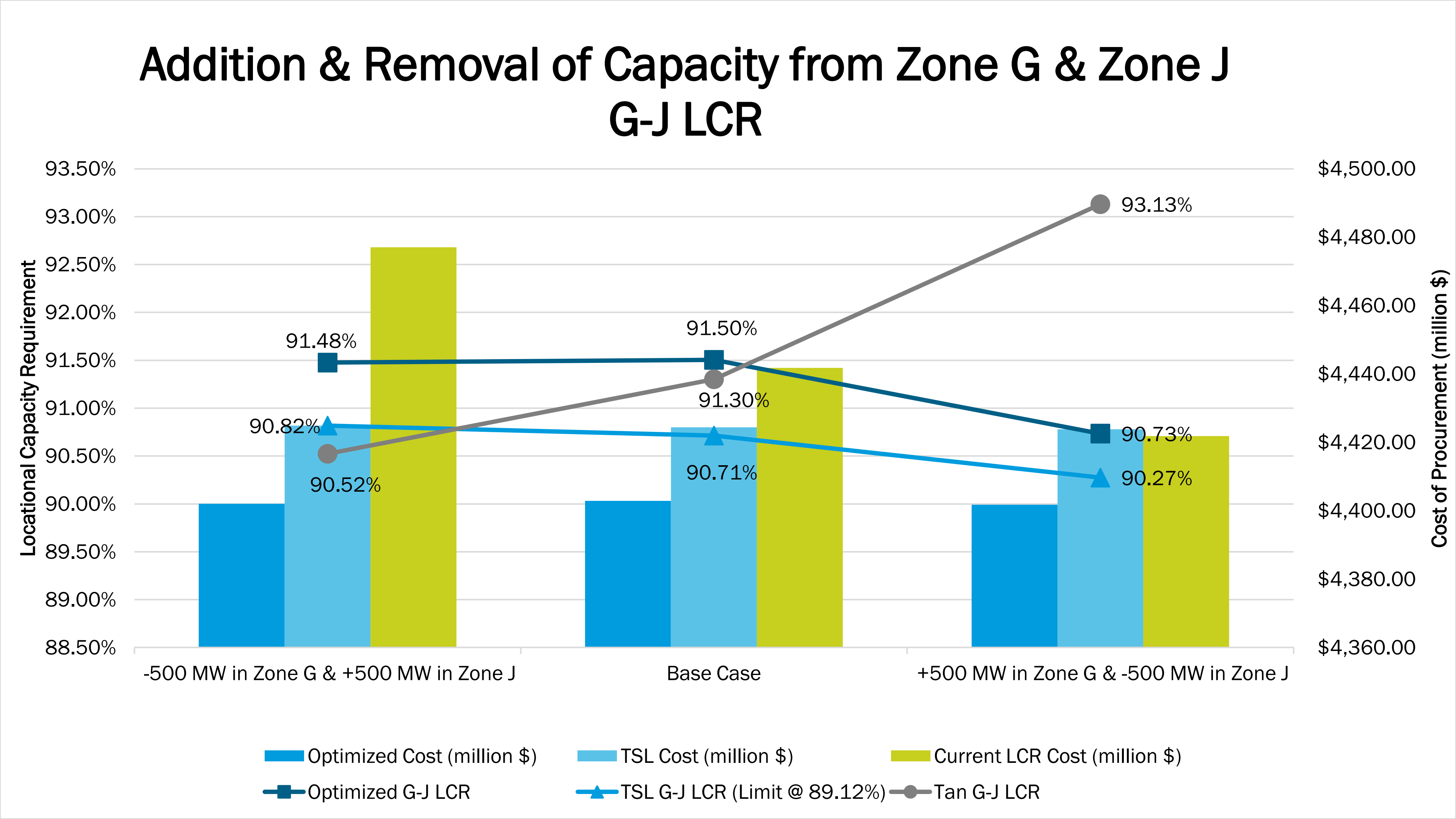
DRAFT – FOR DISCUSSION PURPOSES ONLY

Addition & Removal of Capacity from Zone G & Zone J Zone J LCR





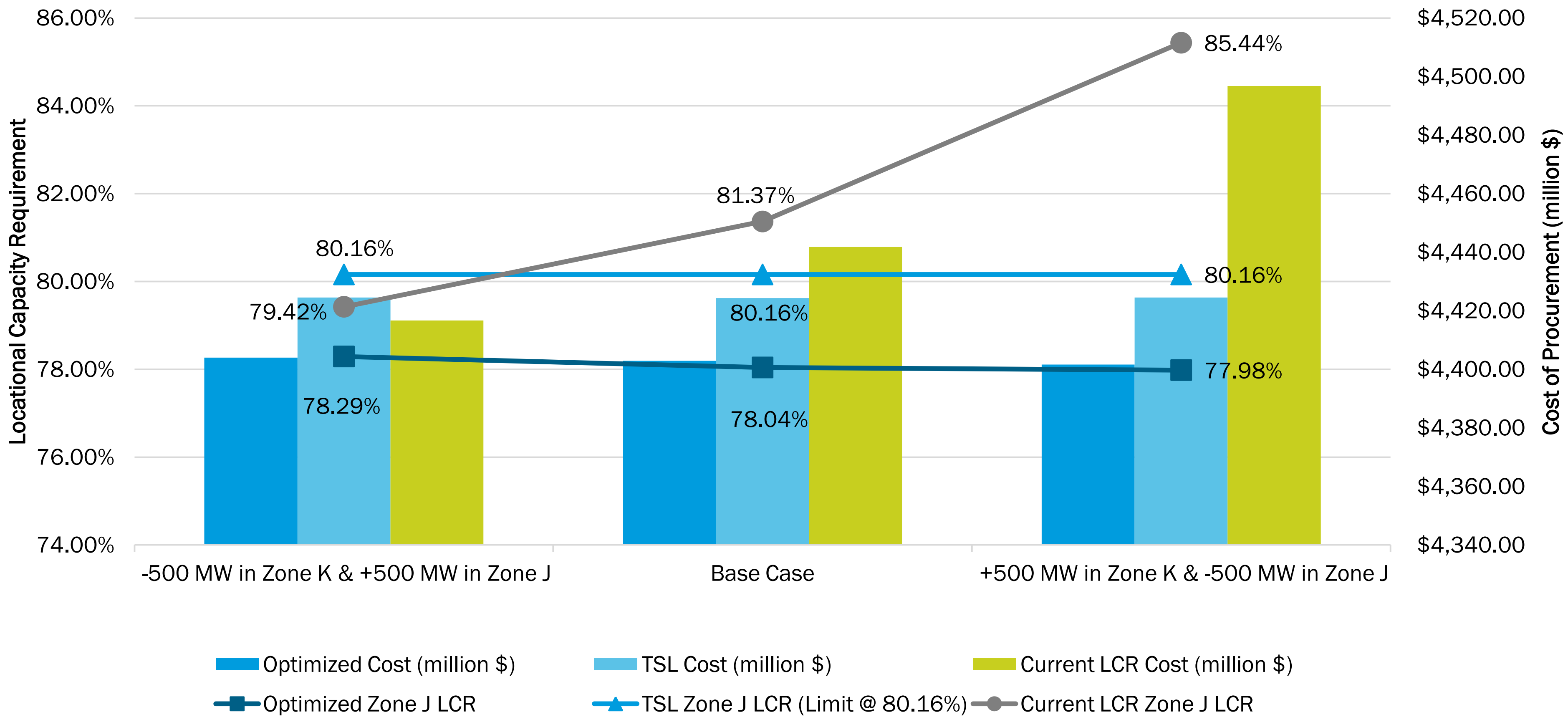
Addition & Removal of Capacity from Zone G & Zone J
Zone K LCR
Locational Capacity Requirement
Cost of Procurement (million $)
106.50%
106.00%
105.50%
105.00%
104.50%
104.00%
103.50%
103.00%
102.50%
102.00%
101.50%
$4,500.00
$4,480.00
$4,460.00
$4,440.00
$4,420.00
$4,400.00
$4,380.00
$4,360.00
105.32%
105.27%
106.04%
104.10%
104.15%
104.56%
103.25%
103.25%
103.15%
-500 MW in Zone G & +500 MW in Zone J
Base Case
+500 MW in Zone G & -500 MW in Zone J
Optimized Cost (million $)
TSL Cost (million $)
Current LCR Cost (million $)
Optimized Zone K LCR
TSL Zone K LCR (Limit @ 102.99%)
Current LCR Zone K LCR

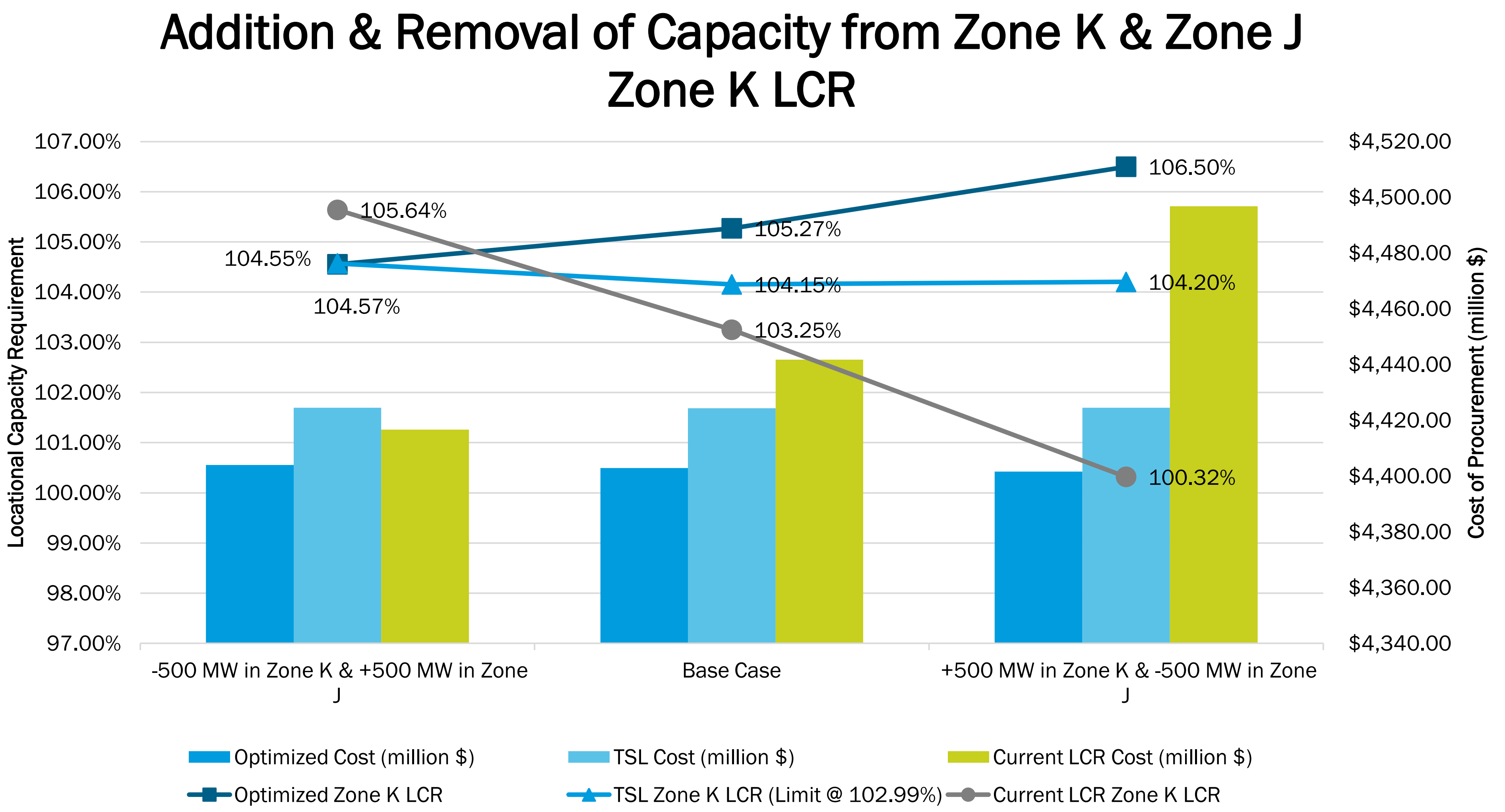


Addition & Removal of Capacity from Zone G & Zone J
G-J LCR
Locational Capacity Requirement
93.50%
93.00%
92.50%
92.00%
91.50%
91.00%
90.50%
90.00%
89.50%
89.00%
88.50%
Cost of Procurement (million $)
$4,500.00
$4,480.00
$4,460.00
$4,440.00
$4,420.00
$4,400.00
$4,380.00
$4,360.00
91.48%
91.50%
93.13%
91.30%
90.82%
90.73%
90.52%
90.71%
90.27%
-500 MW in Zone G & +500 MW in Zone J
Base Case
+500 MW in Zone G & -500 MW in Zone J
Optimized Cost (million $)
TSL Cost (million $)
Current LCR Cost (million $)
Optimized G-J LCR
TSL G-J LCR (Limit @ 89.12%)
Tan G-J LCR

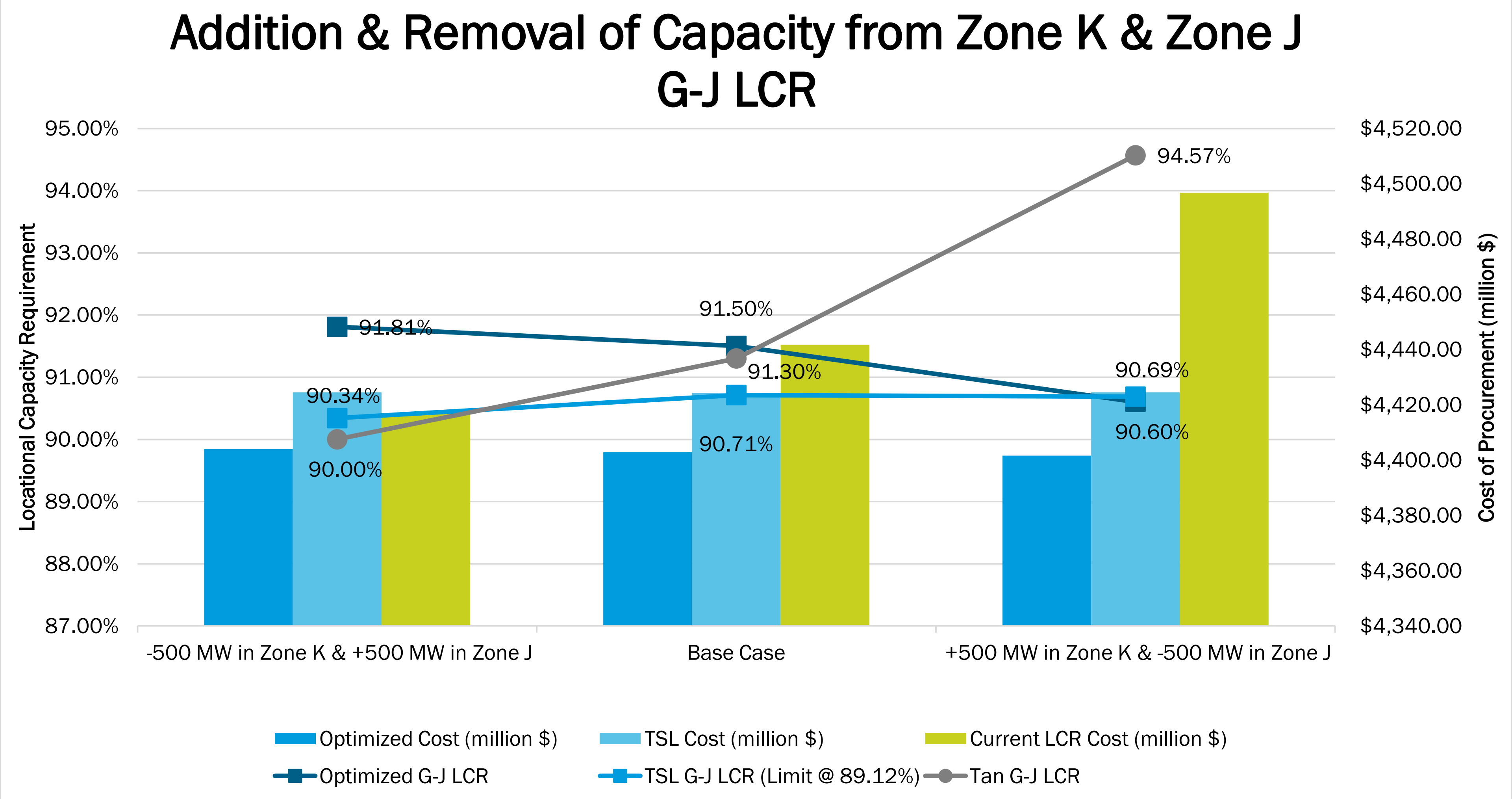
Market Simulations: +/- 500 MW to Zone K and +/-500 MW to Zone J

Addition & Removal of Capacity from Zone K & Zone J
Zone J LCR





Addition & Removal of Capacity from Zone K & Zone J
Zone K LCR
Locational Capacity Requirement
Cost of Procurement (million $)
107.00%
106.00%
105.00%
104.00%
103.00%
102.00%
101.00%
100.00%
99.00%
98.00%
97.00%
$4,520.00
$4,500.00
$4,480.00
$4,460.00
$4,440.00
$4,420.00
$4,400.00
$4,380.00
$4,360.00
$4,340.00
105.64%
104.55%
104.57%
105.27%
104.15%
103.25%
106.50%
104.20%
100.32%
-500 MW in Zone K & +500 MW in Zone J
Base Case
+500 MW in Zone K & -500 MW in Zone J
Optimized Cost (million $)
TSL Cost (million $)
Current LCR Cost (million $)
Optimized Zone K LCR
TSL Zone K LCR (Limit @ 102.99%)
Current LCR Zone K LCR


Addition & Removal of Capacity from Zone K & Zone J
G-J LCR
Locational Capacity Requirement
Cost of Procurement (million $)
95.00%
94.00%
93.00%
92.00%
91.00%
90.00%
89.00%
88.00%
87.00%
$4,520.00
$4,500.00
$4,480.00
$4,460.00
$4,440.00
$4,420.00
$4,400.00
$4,380.00
$4,360.00
$4,340.00
91.81%
90.34%
90.00%
91.50%
91.30%
90.71%
94.57%
90.69%
90.60%
-500 MW in Zone K & +500 MW in Zone J
Base Case
+500 MW in Zone K & -500 MW in Zone J
Optimized Cost (million $)
TSL Cost (million $)
Current LCR Cost (million $)
Optimized G-J LCR
TSL G-J LCR (Limit @ 89.12%)
Tan G-J LCR

Changes in Transmission

Changes in Transmission

- +1000 MW to UPNY-SENY
  - Transmission Security Limit for G-J was recalculated assuming an additional 1000 MW of import capability

+1000 MW to UPNY-SENY

Scenario	Zone J LCR	Zone K LCR	G-J LCR	Cost ($ million)
Current LCR Methodology	79.38%	101.94%	90.18%	$ 4,398.63
Optimized Methodology without Transmission Security Limits (TSL)	77.71%	107.44%	84.29%	$4,365.16
Optimized Methodology with Transmission Security Limits (TSL)	**80.16%**	**103.80%**	**84.96%**	**$4,388.00**

- **G-J import limit was increased by 1000 MW in the TSL calculation resulting in a reduction in the TSL from 89.12% to 82.17%**

DRAFT – FOR DISCUSSION PURPOSES ONLY

+1000 MW to UPNY-SENY

Scenario	Zone J LCR	Zone K LCR	G-J LCR
Current LCR Methodology	9,263 MW	5,532 MW	14,484 MW
Optimized Methodology without Transmission Security Limits (TSL)	9,069 MW	5,831 MW	13,538 MW
Optimized Methodology with Transmission Security Limits (TSL)	9,355 MW	5,633 MW	13,645 MW

Change from Base Case to +1000 MW UPNY-SENY

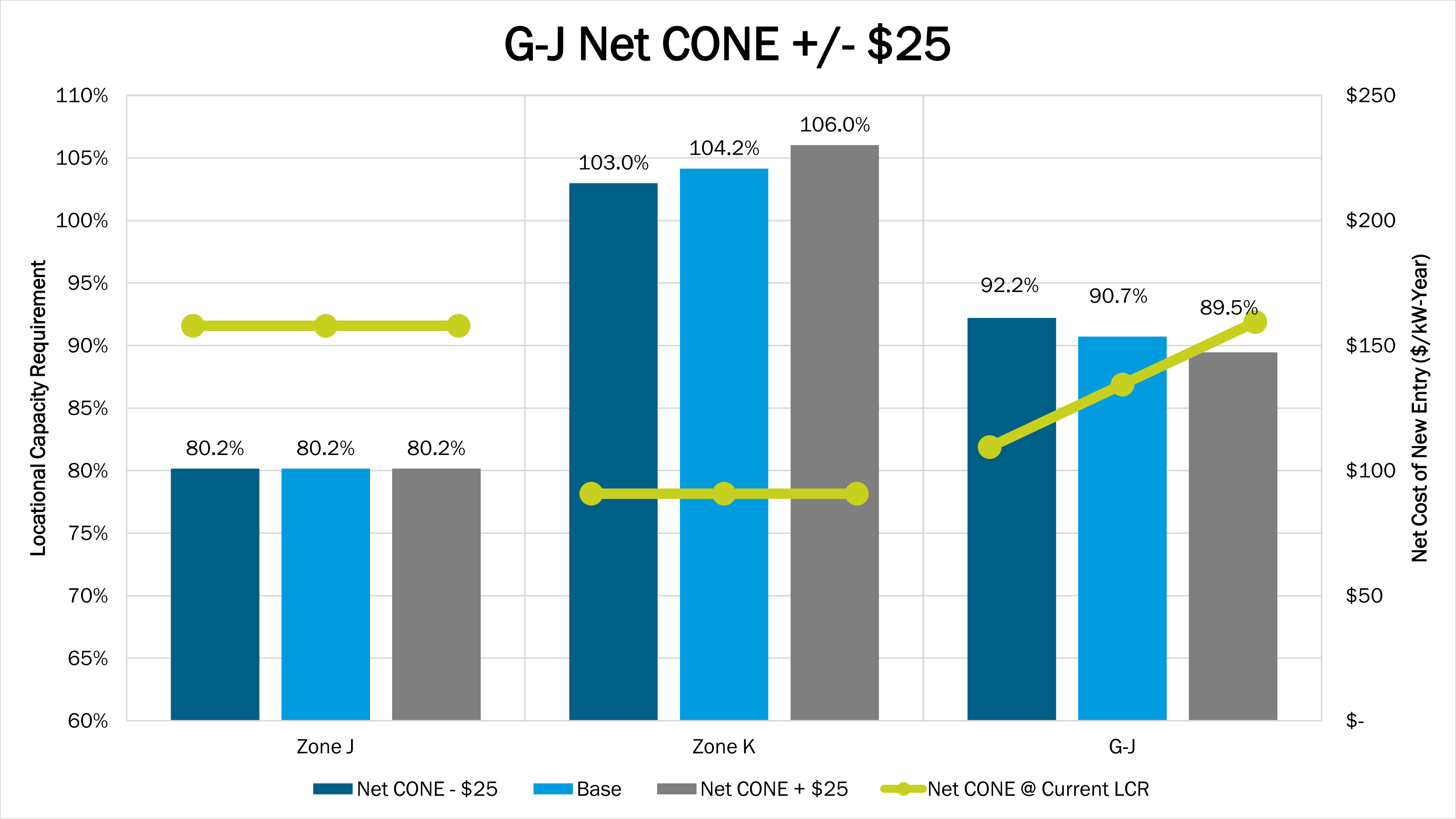
Scenario	Δ Zone J MW	Δ Zone K MW	Δ G-J MW	Δ Total Locality MW
Current LCR Methodology	-232.2	-71.1	-180.5	-483.8
Optimized Methodology without Transmission Security Limits (TSL)	-38.5	117.7	-1159.1	-1079.9
Optimized Methodology with Transmission Security Limits (TSL)	0.0	-19.2	-924.8	-944.1

NEW YORK INDEPENDENT SYSTEM OPERATOR

Changes in Net CONE

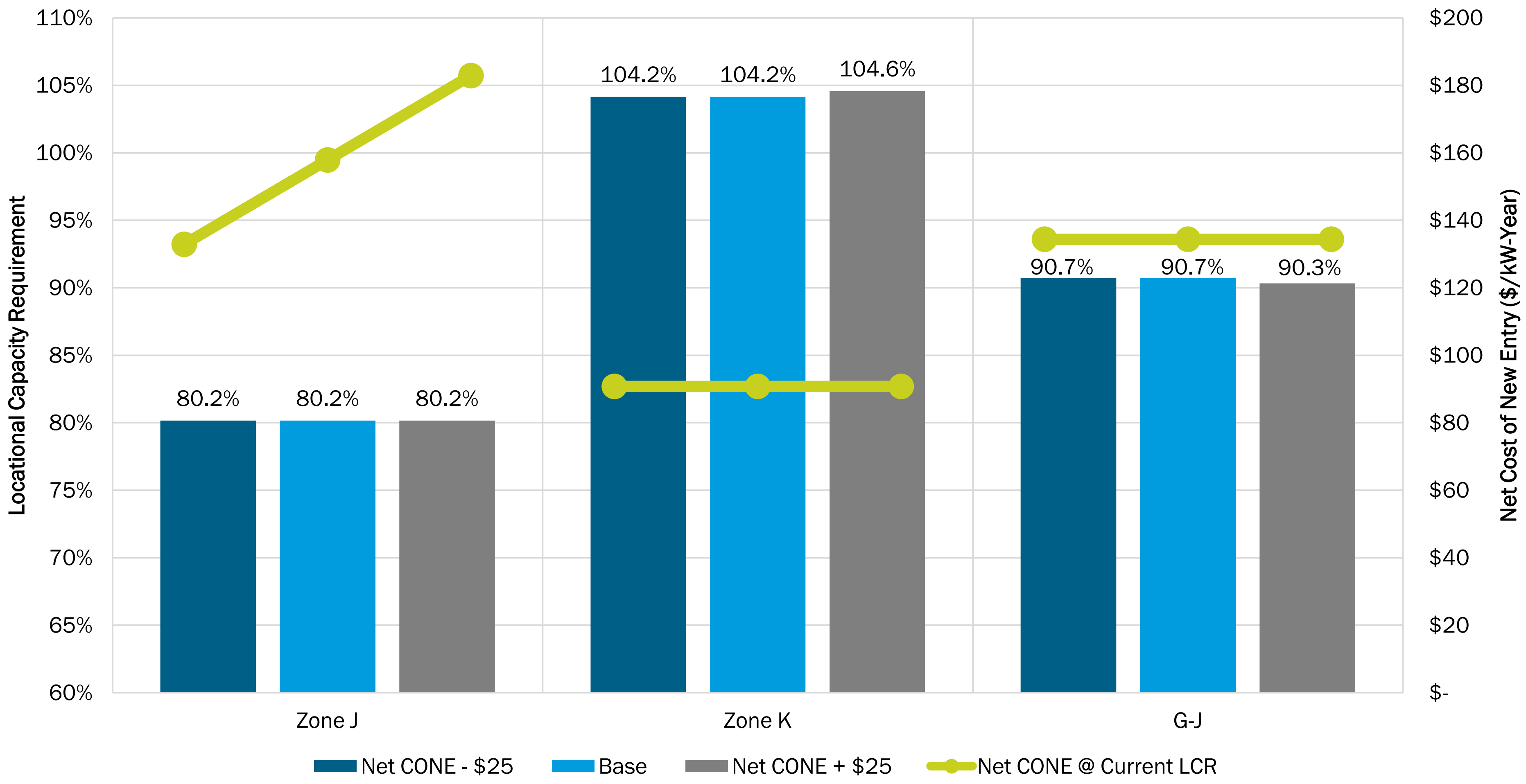
Changes in Net CONE

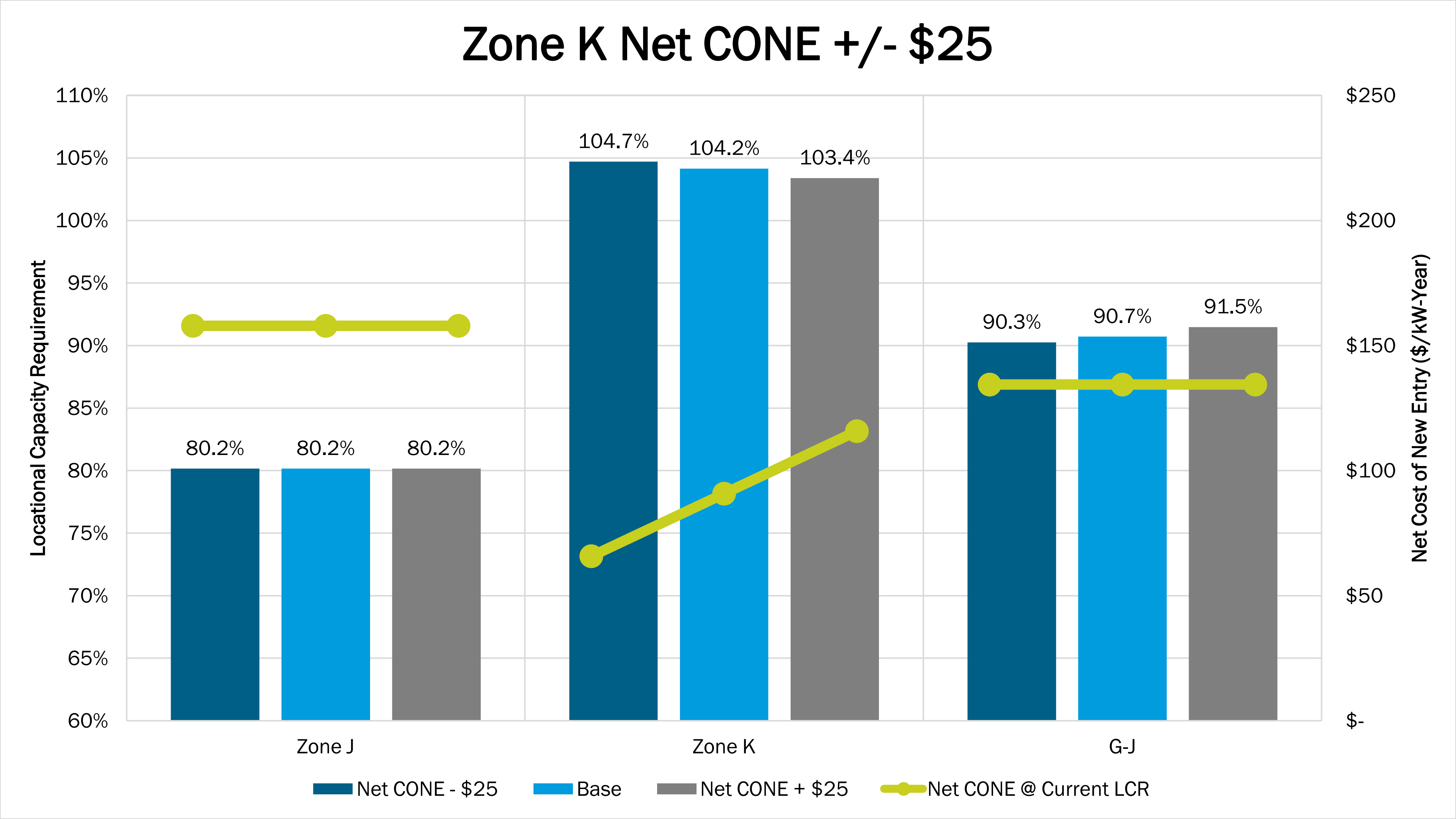
- +/- $25.00 to G-J Net CONE
- +/- $25.00 to Zone J Net CONE
- +/- $25.00 to Zone K Net CONE
- +/- $25.00 to NYCA Net CONE

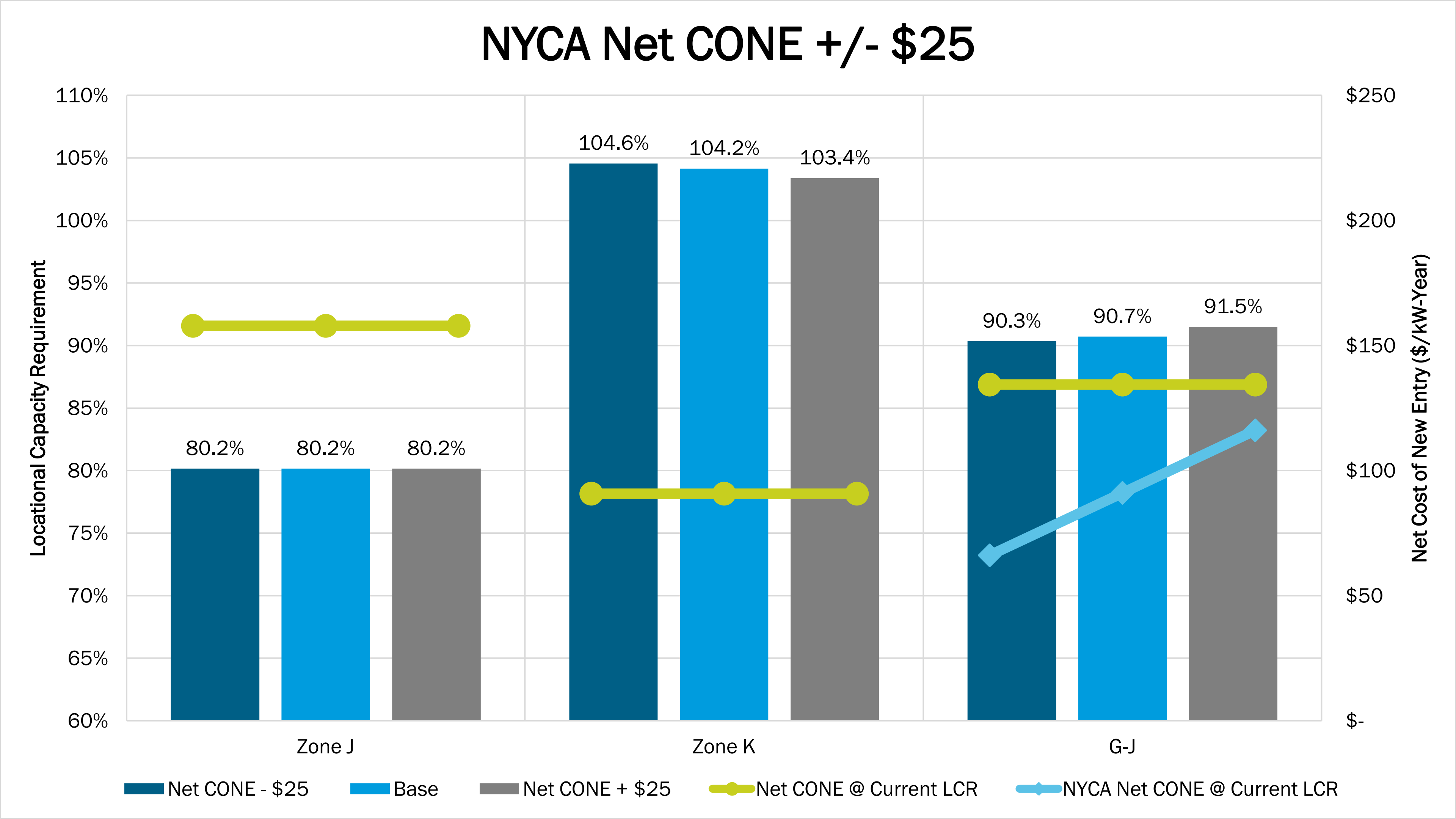


G-J Net CONE +/- $25
Locational Capacity Requirement
Net Cost of New Entry ($/kW-Year)
110%
105%
100%
95%
90%
85%
80%
75%
70%
65%
60%
$250
$200
$150
$100
$50
$-
80.2%
80.2%
80.2%
103.0%
104.2%
106.0%
92.2%
90.7%
89.5%
Zone J
Zone K
G-J
Net CONE - $25
Base
Net CONE + $25
Net CONE @ Current LCR

Zone J Net CONE +/- $25




Zone K Net CONE +/- $25
110%
105%
100%
95%
90%
85%
80%
75%
70%
65%
60%
Locational Capacity Requirement
$250
$200
$150
$100
$50
$-
Net Cost of New Entry ($/kW-Year)
80.2%
80.2%
80.2%
104.7%
104.2%
103.4%
90.3%
90.7%
91.5%
Zone J
Zone K
G-J
Net CONE - $25
Base
Net CONE + $25
Net CONE @ Current LCR


NYCA Net CONE +/- $25
Locational Capacity Requirement
Net Cost of New Entry ($/kW-Year)
110%
105%
100%
95%
90%
85%
80%
75%
70%
65%
60%
$250
$200
$150
$100
$50
$-
80.2%
80.2%
80.2%
104.6%
104.2%
103.4%
90.3%
90.7%
91.5%
Zone J
Zone K
G-J
Net CONE - $25
Base
Net CONE + $25
Net CONE @ Current LCR
NYCA Net CONE @ Current LCR

Next Steps

Other Next Steps

- The NYISO will consider input received during today's ICAP Working Group meeting
- Additional comments sent to deckels@nyiso.com will be considered

Questions?

The Mission of the New York Independent System Operator, in collaboration with its stakeholders, is to serve the public interest and provide benefits to consumers by:

- Maintaining and enhancing regional reliability
- Operating open, fair and competitive wholesale electricity markets
- Planning the power system for the future
- Providing factual information to policy makers, stakeholders and investors in the power system

www.nyiso.com

NEW YORK INDEPENDENT SYSTEM OPERATOR

Exhibit 29

Additional Consumer Impact Analysis: Alternative Methods for Determining LCRs

Tariq N. Niazi

Senior Manager, Consumer Interest Liaison

Installed Capacity Working Group

November 6, 2017

NEW YORK INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY

Background/Overview

- The Consumer Impact Analysis for Alternative Methods for Determining LCRs was presented to stakeholder at the October 11, 2017 ICAP meeting
- During the presentation, some stakeholders requested additional information related to the consumer impact
- This presentation provides additional consumer impact information in response to stakeholder requests
- The October 11, 2017 Consumer Impact presentation is contained in the appendix for easy reference and comparison to the additional information provided in this presentation

Stakeholder Information Requests

- **Stakeholders requested the following additional information:**
  - The October 11, 2017 presentation provided the difference (delta) between the cost of the current and the cost of the optimized LCR methodology for total capacity that cleared in each Locality (Cost of Capacity)
    - Stakeholders wanted to see each Locality's total cost responsibility up to their IRM requirement
    - Additionally, stakeholders wanted to see the total costs (not just the delta) for each Locality between the current and optimized LCR methodologies
- **Stakeholders also requested the historical percentage used in the long term consumer impact analysis**

Additional Cost Impact Analysis

- The tables that follow provide the additional information requested by stakeholders
- The additional analysis follows the same format as the original analysis
  - Short term consumer impact (assumes no changes in generation and/or transmission)
  - Intermediate term consumer impact (generation and transmission resources change)
  - Long term cost impact
    - Long-run equilibrium modelled at the Level of Excess condition (defined in the Demand Curve reset)
    - Historic excess defined as a percentage of excess above the requirement (observed in the last 3 Capability Years in each of the different Localities)

NEW YORK INDEPENDENT SYSTEM OPERATOR

Additional Cost Impact Analysis, Contd.

- The consumer costs shown in the tables for both the current LCRs and optimized LCRs with the Transmission Security Limit (TSL) are based on the full IRM responsibility of each Locality
- The cost of capacity shown in the tables for both the current LCRs and optimized LCRs with the Transmission Security Limit (TSL) are based on the individual Locality requirement and total capacity that cleared in each Locality
- Additionally, the tables that follow show the delta between consumer costs and cost of capacity for the current and optimized LCRs for the different sensitivities for each Locality

NEW YORK INDEPENDENT SYSTEM OPERATOR

	Historic 3 Year % Excess			
	LI	NYC	G-J	NYCA
Summer	7.80%	6.81%	8.10%	5.06%
Winter	10.58%	13.22%	14.70%	10.94%

NEW YORK INDEPENDENT SYSTEM OPERATOR

Total Consumer Costs

Current LCR Methodology

Sensitivity	Short & Intermediate Term Consumer Cost for Current LCR (million $)				
	LI	NYC	GHI	ROS	Total
Base Case	$328	$1,182	$333	$542	$2,385
+500 MW to Zone G at G-J EFORd	$274	$890	$290	$379	$1,833
-500 MW to Zone G at G-J EFORd	$384	$1,580	$420	$701	$3,085
+500MW to Zone J at J EFORd	$280	$654	$230	$376	$1,540
-500MW to Zone J at J EFORd	$378	$1,677	$474	$704	$3,234
+500MW to Zone K at K EFORd	$175	$922	$269	$376	$1,741
-500MW to Zone K at K EFORd	$617	$1,759	$494	$704	$3,574
+500MW to Zone F at F EFORd	$303	$1,094	$318	$369	$2,084
-500MW to Zone F at F EFORd	$344	$1,243	$375	$711	$2,673

NEW YORK INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY

Sensitivity	Short & Intermediate Term Consumer Costs for Current LCR (million $)				
	LI	NYC	GHI	ROS	Total
+1000 MW to UPNYSENY	$263	$847	$296	$542	$1,949
+$25.00 to G-J	$328	$1,193	$387	$542	$2,450
-$25.00 to G-J	$328	$1,172	$281	$542	$2,323
+$25.00 Zone J	$328	$1,346	$333	$542	$2,549
-$25.00 to Zone J	$328	$1,018	$333	$542	$2,221
+$25.00 to Zone K	$414	$1,182	$333	$542	$2,471
-$25.00 to Zone K	$261	$1,182	$333	$542	$2,318
+$25.00 to NYCA	$338	$1,214	$349	$691	$2,592
-$25.00 to NYCA	$324	$1,151	$322	$394	$2,190
+500 MW in Zone G & -500 MW in Zone J	$322	$1,469	$447	$545	$2,784
+500 MW in Zone K & -500 MW in Zone J	$252	$1,478	$419	$542	$2,690
-500 MW in Zone G & +500 MW in Zone J	$328	$1,076	$305	$540	$2,249
-500 MW in Zone K & +500 MW in Zone J	$592	$1,280	$368	$542	$2,783

Sensitivity	Consumer Costs at LOE for Current LCR (million $)				
	LI	NYC	GHI	ROS	Total
Base Case	$732	$2,315	$761	$1,437	$5,245
+500 MW to Zone G at G-J EFORd	$730	$2,318	$768	$1,437	$5,253
-500 MW to Zone G at G-J EFORd	$735	$2,321	$756	$1,437	$5,249
+500MW to Zone J at J EFORd	$731	$2,323	$763	$1,437	$5,253
-500MW to Zone J at J EFORd	$735	$2,305	$759	$1,437	$5,235
+500MW to Zone K at K EFORd	$736	$2,301	$758	$1,437	$5,232
-500MW to Zone K at K EFORd	$726	$2,353	$769	$1,437	$5,284
+500MW to Zone F at F EFORd	$732	$2,313	$761	$1,437	$5,242
-500MW to Zone F at F EFORd	$733	$2,318	$762	$1,437	$5,250

Sensitivity	Consumer Costs at LOE for Current LCR (million $)				
	LI	NYC	GHI	ROS	Total
+1000 MW to UPNYSENY	$729	$2,294	$757	$1,437	$5,217
+$25.00 to G-J	$732	$2,344	$882	$1,437	$5,396
-$25.00 to G-J	$732	$2,290	$640	$1,437	$5,100
+$25.00 Zone J	$732	$2,621	$761	$1,437	$5,551
-$25.00 to Zone J	$732	$2,022	$761	$1,437	$4,952
+$25.00 to Zone K	$922	$2,315	$761	$1,437	$5,435
-$25.00 to Zone K	$667	$2,315	$761	$1,437	$5,180
+$25.00 to NYCA	$850	$2,396	$791	$1,831	$5,868
-$25.00 to NYCA	$721	$2,234	$730	$1,043	$4,727
+500 MW in Zone G & -500 MW in Zone J	$732	$2,312	$767	$1,437	$5,248
+500 MW in Zone K & -500 MW in Zone J	$739	$2,293	$756	$1,437	$5,225
-500 MW in Zone G & +500 MW in Zone J	$732	$2,331	$758	$1,437	$5,259
-500 MW in Zone K & +500 MW in Zone J	$725	$2,364	$771	$1,437	$5,298

Sensitivity	Consumer Costs at Historic Excess for Current LCR (million $)				
	LI	NYC	GHI	ROS	Total
Base Case	$474	$1,171	$237	$531	$2,412
+500 MW to Zone G at G-J EFORd	$472	$1,163	$238	$531	$2,404
-500 MW to Zone G at G-J EFORd	$476	$1,184	$237	$531	$2,427
+500MW to Zone J at J EFORd	$472	$1,175	$237	$531	$2,415
-500MW to Zone J at J EFORd	$476	$1,164	$237	$531	$2,407
+500MW to Zone K at K EFORd	$476	$1,162	$237	$531	$2,406
-500MW to Zone K at K EFORd	$468	$1,194	$238	$531	$2,431
+500MW to Zone F at F EFORd	$473	$1,169	$237	$531	$2,409
-500MW to Zone F at F EFORd	$474	$1,172	$237	$531	$2,414

Sensitivity	Consumer Costs at Historic Excess for Current LCR (million $)				
	LI	NYC	GHI	ROS	Total
+1000 MW to UPNYSENY	$471	$1,156	$237	$531	$2,395
+$25.00 to G-J	$474	$1,179	$270	$531	$2,454
-$25.00 to G-J	$474	$1,163	$204	$531	$2,371
+$25.00 Zone J	$474	$1,337	$237	$531	$2,578
-$25.00 to Zone J	$474	$1,005	$237	$531	$2,247
+$25.00 to Zone K	$599	$1,171	$237	$531	$2,538
-$25.00 to Zone K	$357	$1,171	$237	$531	$2,296
+$25.00 to NYCA	$479	$1,200	$254	$676	$2,609
-$25.00 to NYCA	$469	$1,142	$221	$385	$2,217
+500 MW in Zone G & -500 MW in Zone J	$474	$1,159	$238	$531	$2,401
+500 MW in Zone K & -500 MW in Zone J	$479	$1,156	$237	$531	$2,403
-500 MW in Zone G & +500 MW in Zone J	$474	$1,190	$237	$531	$2,431
-500 MW in Zone K & +500 MW in Zone J	$467	$1,201	$239	$531	$2,438

Optimized Methodology with TSL

NEW YORK INDEPENDENT SYSTEM OPERATOR

Sensitivity	Short & Intermediate Term Consumer Costs for Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
Base Case	$380	$963	$312	$542	$2,197
+500 MW to Zone G at G-J EFORd	$400	$912	$181	$379	$1,872
-500 MW to Zone G at G-J EFORd	$402	$1,201	$452	$701	$2,756
+500MW to Zone J at J EFORd	$377	$512	$193	$376	$1,458
-500MW to Zone J at J EFORd	$381	$1,641	$473	$704	$3,199
+500MW to Zone K at K EFORd	$175	$925	$263	$376	$1,740
-500MW to Zone K at K EFORd	$794	$1,013	$348	$704	$2,859
+500MW to Zone F at F EFORd	$387	$923	$257	$369	$1,936
-500MW to Zone F at F EFORd	$411	$1,017	$352	$711	$2,491

DRAFT – FOR DISCUSSION PURPOSES ONLY

Sensitivity	Short & Intermediate Term Consumer Costs for Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
+1000 MW to UPNYSENY	$360	$942	$204	$542	$2,047
+$25.00 to G-J	$484	$963	$313	$542	$2,302
-$25.00 to G-J	$313	$976	$325	$542	$2,156
+$25.00 Zone J	$404	$1,090	$301	$542	$2,337
-$25.00 to Zone J	$380	$857	$312	$542	$2,090
+$25.00 to Zone K	$424	$970	$345	$542	$2,281
-$25.00 to Zone K	$302	$961	$299	$542	$2,104
+$25.00 to NYCA	$342	$1,001	$357	$691	$2,393
-$25.00 to NYCA	$399	$928	$282	$394	$2,003
+500 MW in Zone G & -500 MW in Zone J	$403	$1,579	$301	$545	$2,828
+500 MW in Zone K & -500 MW in Zone J	$252	$1,605	$439	$542	$2,838
-500 MW in Zone G & +500 MW in Zone J	$377	$833	$313	$540	$2,064
-500 MW in Zone K & +500 MW in Zone J	$788	$608	$229	$542	$2,167

DRAFT – FOR DISCUSSION PURPOSES ONLY

Sensitivity	Consumer Costs at LOE for Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
Base Case	$735	$2,303	$759	$1,437	$5,234
+500 MW to Zone G at G-J EFORd	$736	$2,300	$758	$1,437	$5,230
-500 MW to Zone G at G-J EFORd	$736	$2,301	$758	$1,437	$5,231
+500MW to Zone J at J EFORd	$735	$2,303	$759	$1,437	$5,234
-500MW to Zone J at J EFORd	$735	$2,303	$759	$1,437	$5,234
+500MW to Zone K at K EFORd	$736	$2,300	$758	$1,437	$5,231
-500MW to Zone K at K EFORd	$735	$2,302	$759	$1,437	$5,233
+500MW to Zone F at F EFORd	$735	$2,299	$757	$1,437	$5,228
-500MW to Zone F at F EFORd	$736	$2,303	$759	$1,437	$5,235

Sensitivity	Consumer Costs at LOE for Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
+1000 MW to UPNYSENY	$734	$2,266	$740	$1,437	$5,177
+$25.00 to G-J	$740	$2,321	$873	$1,437	$5,371
-$25.00 to G-J	$732	$2,280	$642	$1,437	$5,090
+$25.00 Zone J	$736	$2,602	$758	$1,437	$5,532
-$25.00 to Zone J	$735	$2,017	$759	$1,437	$4,948
+$25.00 to Zone K	$923	$2,308	$761	$1,437	$5,429
-$25.00 to Zone K	$667	$2,300	$757	$1,437	$5,161
+$25.00 to NYCA	$850	$2,388	$792	$1,831	$5,861
-$25.00 to NYCA	$726	$2,216	$726	$1,043	$4,710
+500 MW in Zone G & -500 MW in Zone J	$736	$2,300	$758	$1,437	$5,230
+500 MW in Zone K & -500 MW in Zone J	$736	$2,300	$758	$1,437	$5,231
-500 MW in Zone G & +500 MW in Zone J	$735	$2,303	$759	$1,437	$5,234
-500 MW in Zone K & +500 MW in Zone J	$735	$2,302	$759	$1,437	$5,233

Sensitivity	Consumer Costs at Historic Excess for Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
Base Case	$476	$1,162	$237	$531	$2,405
+500 MW to Zone G at G-J EFORd	$477	$1,162	$237	$531	$2,406
-500 MW to Zone G at G-J EFORd	$477	$1,162	$237	$531	$2,406
+500MW to Zone J at J EFORd	$476	$1,162	$237	$531	$2,405
-500MW to Zone J at J EFORd	$476	$1,162	$237	$531	$2,405
+500MW to Zone K at K EFORd	$477	$1,162	$237	$531	$2,406
-500MW to Zone K at K EFORd	$476	$1,162	$237	$531	$2,406
+500MW to Zone F at F EFORd	$476	$1,162	$237	$531	$2,405
-500MW to Zone F at F EFORd	$477	$1,162	$237	$531	$2,407

Sensitivity	Consumer Costs at Historic Excess for Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
+1000 MW to UPNYSENY	$475	$1,156	$235	$531	$2,396
+$25.00 to G-J	$480	$1,168	$269	$531	$2,448
-$25.00 to G-J	$473	$1,154	$204	$531	$2,362
+$25.00 Zone J	$477	$1,325	$237	$531	$2,569
-$25.00 to Zone J	$476	$999	$237	$531	$2,243
+$25.00 to Zone K	$600	$1,163	$237	$531	$2,531
-$25.00 to Zone K	$359	$1,162	$237	$531	$2,288
+$25.00 to NYCA	$479	$1,192	$254	$676	$2,601
-$25.00 to NYCA	$473	$1,132	$220	$385	$2,209
+500 MW in Zone G & -500 MW in Zone J	$477	$1,162	$237	$531	$2,406
+500 MW in Zone K & -500 MW in Zone J	$477	$1,162	$237	$531	$2,406
-500 MW in Zone G & +500 MW in Zone J	$476	$1,162	$237	$531	$2,405
-500 MW in Zone K & +500 MW in Zone J	$476	$1,162	$237	$531	$2,406

Change between Current LCR and Optimized with TSL

Sensitivity	Δ Short & Intermediate Term Consumer Costs from Current LCR to Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
Base Case	$52	-$219	-$21	$0	-$188
+500 MW to Zone G at G-J EFORd	$126	$23	-$109	$0	$40
-500 MW to Zone G at G-J EFORd	$17	-$379	$32	$0	-$329
+500MW to Zone J at J EFORd	$97	-$141	-$37	$0	-$82
-500MW to Zone J at J EFORd	$3	-$37	-$1	$0	-$34
+500MW to Zone K at K EFORd	$0	$4	-$5	$0	-$2
-500MW to Zone K at K EFORd	$177	-$746	-$146	$0	-$715
+500MW to Zone F at F EFORd	$84	-$171	-$62	$0	-$149
-500MW to Zone F at F EFORd	$67	-$227	-$23	$0	-$182

Sensitivity	Δ Short & Intermediate Term Consumer Costs from Current LCR to Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
+1000 MW to UPNYSENY	$96	$95	-$93	$0	$99
+$25.00 to G-J	$156	-$229	-$75	$0	-$148
-$25.00 to G-J	-$15	-$196	$44	$0	-$167
+$25.00 Zone J	$76	-$256	-$32	$0	-$212
-$25.00 to Zone J	$52	-$161	-$21	$0	-$131
+$25.00 to Zone K	$10	-$212	$11	$0	-$190
-$25.00 to Zone K	$41	-$221	-$34	$0	-$214
+$25.00 to NYCA	$5	-$213	$9	$0	-$199
-$25.00 to NYCA	$75	-$222	-$40	$0	-$187
+500 MW in Zone G & -500 MW in Zone J	$81	$110	-$146	$0	$44
+500 MW in Zone K & -500 MW in Zone J	$0	$127	$20	$0	$147
-500 MW in Zone G & +500 MW in Zone J	$49	-$243	$8	$0	-$185
-500 MW in Zone K & +500 MW in Zone J	$195	-$672	-$140	$0	-$616

DRAFT – FOR DISCUSSION PURPOSES ONLY

Sensitivity	Δ Consumer Costs at LOE from Current LCR to Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
Base Case	$3	-$12	-$2	$0	-$12
+500 MW to Zone G at G-J EFORd	$6	-$19	-$10	$0	-$23
-500 MW to Zone G at G-J EFORd	$1	-$20	$2	$0	-$18
+500MW to Zone J at J EFORd	$4	-$20	-$4	$0	-$20
-500MW to Zone J at J EFORd	$0	-$2	$0	$0	-$2
+500MW to Zone K at K EFORd	$0	-$1	$0	$0	-$1
-500MW to Zone K at K EFORd	$9	-$50	-$10	$0	-$51
+500MW to Zone F at F EFORd	$4	-$13	-$3	$0	-$13
-500MW to Zone F at F EFORd	$3	-$15	-$2	$0	-$14

NEW YORK INDEPENDENT SYSTEM OPERATOR

Sensitivity	Δ Consumer Costs at LOE from Current LCR to Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
+1000 MW to UPNYSENY	$5	-$28	-$17	$0	-$40
+$25.00 to G-J	$7	-$23	-$9	$0	-$24
-$25.00 to G-J	-$1	-$10	$1	$0	-$10
+$25.00 Zone J	$3	-$19	-$3	$0	-$19
-$25.00 to Zone J	$3	-$5	-$2	$0	-$4
+$25.00 to Zone K	$1	-$7	$0	$0	-$6
-$25.00 to Zone K	$0	-$15	-$3	$0	-$19
+$25.00 to NYCA	$0	-$8	$0	$0	-$8
-$25.00 to NYCA	$6	-$18	-$4	$0	-$17
+500 MW in Zone G & -500 MW in Zone J	$4	-$12	-$9	$0	-$18
+500 MW in Zone K & -500 MW in Zone J	-$3	$8	$1	$0	$6
-500 MW in Zone G & +500 MW in Zone J	$2	-$28	$1	$0	-$24
-500 MW in Zone K & +500 MW in Zone J	$10	-$62	-$12	$0	-$64

DRAFT – FOR DISCUSSION PURPOSES ONLY

Sensitivity	Δ Consumer Costs at Historic Excess from Current LCR to Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
Base Case	$2	-$9	$0	$0	-$7
+500 MW to Zone G at G-J EFORd	$5	-$2	-$1	$0	$2
-500 MW to Zone G at G-J EFORd	$1	-$22	$0	$0	-$21
+500MW to Zone J at J EFORd	$4	-$13	-$1	$0	-$10
-500MW to Zone J at J EFORd	$0	-$1	$0	$0	-$1
+500MW to Zone K at K EFORd	$0	$0	$0	$0	$0
-500MW to Zone K at K EFORd	$8	-$32	-$1	$0	-$25
+500MW to Zone F at F EFORd	$3	-$7	$0	$0	-$4
-500MW to Zone F at F EFORd	$3	-$10	$0	$0	-$7

NEW YORK INDEPENDENT SYSTEM OPERATOR

Sensitivity	Δ Consumer Costs at Historic Excess from Current LCR to Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
+1000 MW to UPNYSENY	$4	-$1	-$2	$0	$1
+$25.00 to G-J	$6	-$11	-$1	$0	-$6
-$25.00 to G-J	-$1	-$9	$0	$0	-$10
+$25.00 Zone J	$3	-$12	$0	$0	-$9
-$25.00 to Zone J	$2	-$6	$0	$0	-$4
+$25.00 to Zone K	$0	-$8	$0	$0	-$7
-$25.00 to Zone K	$2	-$9	$0	$0	-$8
+$25.00 to NYCA	$0	-$8	$0	$0	-$8
-$25.00 to NYCA	$4	-$10	-$1	$0	-$7
+500 MW in Zone G & -500 MW in Zone J	$3	$3	-$1	$0	$5
+500 MW in Zone K & -500 MW in Zone J	-$2	$5	$0	$0	$3
-500 MW in Zone G & +500 MW in Zone J	$2	-$28	$0	$0	-$26
-500 MW in Zone K & +500 MW in Zone J	$9	-$39	-$2	$0	-$32

Total Cost of Capacity

Current LCR Methodology

Sensitivity	Short & Intermediate Term Cost of Capacity for Current LCR (million $)				
	LI	NYC	GHI	ROS	Total
Base Case	$313	$1,011	$348	$714	$2,385
+500 MW to Zone G at G-J EFORd	$262	$744	$333	$494	$1,833
-500 MW to Zone G at G-J EFORd	$368	$1,380	$404	$934	$3,085
+500MW to Zone J at J EFORd	$268	$548	$234	$490	$1,540
-500MW to Zone J at J EFORd	$361	$1,421	$514	$938	$3,234
+500MW to Zone K at K EFORd	$175	$792	$284	$491	$1,741
-500MW to Zone K at K EFORd	$577	$1,530	$529	$938	$3,574
+500MW to Zone F at F EFORd	$291	$955	$344	$495	$2,085
-500MW to Zone F at F EFORd	$328	$1,038	$386	$921	$2,673

NEW YORK INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY

Sensitivity	Short & Intermediate Term Cost of Capacity for Current LCR (million $)				
	LI	NYC	GHI	ROS	Total
+1000 MW to UPNYSENY	$248	$683	$303	$714	$1,949
+$25.00 to G-J	$313	$1,011	$413	$714	$2,450
-$25.00 to G-J	$313	$1,011	$285	$714	$2,323
+$25.00 Zone J	$313	$1,174	$348	$714	$2,549
-$25.00 to Zone J	$313	$847	$348	$714	$2,221
+$25.00 to Zone K	$399	$1,011	$348	$714	$2,472
-$25.00 to Zone K	$246	$1,011	$348	$714	$2,318
+$25.00 to NYCA	$318	$1,011	$352	$911	$2,592
-$25.00 to NYCA	$313	$1,011	$348	$518	$2,190
+500 MW in Zone G & -500 MW in Zone J	$307	$1,229	$530	$718	$2,784
+500 MW in Zone K & -500 MW in Zone J	$255	$1,262	$460	$714	$2,690
-500 MW in Zone G & +500 MW in Zone J	$312	$940	$284	$712	$2,249
-500 MW in Zone K & +500 MW in Zone J	$559	$1,126	$384	$714	$2,783

NEW YORK INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY

Sensitivity	Cost of Capacity at LOE for Current LCR (million $)				
	LI	NYC	GHI	ROS	Total
Base Case	$689	$1,887	$782	$1,888	$5,245
+500 MW to Zone G at G-J EFORd	$682	$1,847	$867	$1,857	$5,253
-500 MW to Zone G at G-J EFORd	$697	$1,943	$702	$1,907	$5,249
+500MW to Zone J at J EFORd	$683	$1,901	$788	$1,882	$5,253
-500MW to Zone J at J EFORd	$696	$1,861	$785	$1,893	$5,235
+500MW to Zone K at K EFORd	$700	$1,854	$783	$1,895	$5,232
-500MW to Zone K at K EFORd	$668	$1,967	$789	$1,861	$5,284
+500MW to Zone F at F EFORd	$686	$1,878	$787	$1,891	$5,242
-500MW to Zone F at F EFORd	$691	$1,891	$786	$1,882	$5,250

NEW YORK INDEPENDENT SYSTEM OPERATOR

Sensitivity	Cost of Capacity at LOE for Current LCR (million $)				
	LI	NYC	GHI	ROS	Total
+1000 MW to UPNYSENY	$678	$1,835	$790	$1,915	$5,217
+$25.00 to G-J	$689	$1,891	$927	$1,888	$5,396
-$25.00 to G-J	$689	$1,887	$636	$1,888	$5,100
+$25.00 Zone J	$689	$2,193	$782	$1,888	$5,551
-$25.00 to Zone J	$689	$1,594	$782	$1,888	$4,952
+$25.00 to Zone K	$879	$1,887	$782	$1,888	$5,435
-$25.00 to Zone K	$624	$1,887	$782	$1,888	$5,180
+$25.00 to NYCA	$795	$1,887	$782	$2,405	$5,869
-$25.00 to NYCA	$689	$1,887	$782	$1,370	$4,727
+500 MW in Zone G & -500 MW in Zone J	$689	$1,831	$871	$1,858	$5,248
+500 MW in Zone K & -500 MW in Zone J	$709	$1,836	$784	$1,896	$5,225
-500 MW in Zone G & +500 MW in Zone J	$689	$1,965	$703	$1,901	$5,259
-500 MW in Zone K & +500 MW in Zone J	$665	$1,993	$790	$1,850	$5,298

NEW YORK INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY

Sensitivity	Cost of Capacity at Historic Excess for Current LCR (million $)				
	LI	NYC	GHI	ROS	Total
Base Case	$456	$1,023	$249	$685	$2,412
+500 MW to Zone G at G-J EFORd	$452	$1,004	$275	$673	$2,404
-500 MW to Zone G at G-J EFORd	$461	$1,050	$225	$692	$2,427
+500MW to Zone J at J EFORd	$453	$1,030	$251	$682	$2,416
-500MW to Zone J at J EFORd	$460	$1,010	$250	$687	$2,407
+500MW to Zone K at K EFORd	$462	$1,007	$249	$687	$2,406
-500MW to Zone K at K EFORd	$445	$1,061	$251	$674	$2,431
+500MW to Zone F at F EFORd	$455	$1,019	$250	$686	$2,409
-500MW to Zone F at F EFORd	$457	$1,025	$250	$682	$2,414

Sensitivity	Cost of Capacity at Historic Excess for Current LCR (million $)				
	LI	NYC	GHI	ROS	Total
+1000 MW to UPNYSENY	$451	$998	$252	$695	$2,395
+$25.00 to G-J	$456	$1,023	$290	$685	$2,454
-$25.00 to G-J	$456	$1,023	$208	$685	$2,371
+$25.00 Zone J	$456	$1,189	$249	$685	$2,578
-$25.00 to Zone J	$456	$857	$249	$685	$2,247
+$25.00 to Zone K	$582	$1,023	$249	$685	$2,538
-$25.00 to Zone K	$340	$1,023	$249	$685	$2,296
+$25.00 to NYCA	$456	$1,023	$257	$873	$2,609
-$25.00 to NYCA	$456	$1,023	$241	$497	$2,217
+500 MW in Zone G & -500 MW in Zone J	$456	$996	$276	$673	$2,401
+500 MW in Zone K & -500 MW in Zone J	$467	$998	$250	$688	$2,403
-500 MW in Zone G & +500 MW in Zone J	$456	$1,060	$225	$690	$2,431
-500 MW in Zone K & +500 MW in Zone J	$443	$1,074	$251	$670	$2,438

NEW YORK INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY

Optimized Methodology with TSL

Sensitivity	Short & Intermediate Term Cost of Capacity for Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
Base Case	$365	$796	$322	$714	$2,197
+500 MW to Zone G at G-J EFORd	$388	$796	$194	$494	$1,872
-500 MW to Zone G at G-J EFORd	$386	$997	$441	$934	$2,756
+500MW to Zone J at J EFORd	$365	$412	$191	$490	$1,458
-500MW to Zone J at J EFORd	$365	$1,384	$512	$938	$3,199
+500MW to Zone K at K EFORd	$175	$796	$277	$491	$1,740
-500MW to Zone K at K EFORd	$754	$814	$353	$938	$2,859
+500MW to Zone F at F EFORd	$375	$796	$270	$495	$1,936
-500MW to Zone F at F EFORd	$395	$816	$359	$921	$2,491

Sensitivity	Short & Intermediate Term Cost of Capacity for Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
+1000 MW to UPNYSENY	$344	$796	$193	$714	$2,047
+$25.00 to G-J	$469	$796	$323	$714	$2,302
-$25.00 to G-J	$298	$806	$338	$714	$2,156
+$25.00 Zone J	$388	$925	$309	$714	$2,337
-$25.00 to Zone J	$365	$690	$322	$714	$2,090
+$25.00 to Zone K	$409	$796	$362	$714	$2,281
-$25.00 to Zone K	$287	$796	$307	$714	$2,104
+$25.00 to NYCA	$323	$796	$363	$911	$2,393
-$25.00 to NYCA	$388	$796	$300	$518	$2,003
+500 MW in Zone G & -500 MW in Zone J	$388	$1,384	$338	$718	$2,828
+500 MW in Zone K & -500 MW in Zone J	$255	$1,384	$485	$714	$2,838
-500 MW in Zone G & +500 MW in Zone J	$362	$697	$293	$712	$2,064
-500 MW in Zone K & +500 MW in Zone J	$754	$477	$222	$714	$2,167

NEW YORK INDEPENDENT SYSTEM OPERATOR

Sensitivity	Cost of Capacity at LOE for Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
Base Case	$697	$1,855	$789	$1,893	$5,234
+500 MW to Zone G at G-J EFORd	$700	$1,855	$777	$1,898	$5,230
-500 MW to Zone G at G-J EFORd	$700	$1,855	$781	$1,896	$5,231
+500MW to Zone J at J EFORd	$697	$1,855	$789	$1,893	$5,234
-500MW to Zone J at J EFORd	$697	$1,855	$789	$1,893	$5,234
+500MW to Zone K at K EFORd	$700	$1,855	$779	$1,897	$5,231
-500MW to Zone K at K EFORd	$697	$1,855	$788	$1,893	$5,233
+500MW to Zone F at F EFORd	$698	$1,855	$775	$1,901	$5,228
-500MW to Zone F at F EFORd	$701	$1,855	$792	$1,888	$5,236

DRAFT – FOR DISCUSSION PURPOSES ONLY

Sensitivity	Cost of Capacity at LOE for Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
+1000 MW to UPNYSENY	$694	$1,855	$636	$1,992	$5,177
+$25.00 to G-J	$712	$1,859	$896	$1,903	$5,371
-$25.00 to G-J	$687	$1,855	$675	$1,874	$5,091
+$25.00 Zone J	$700	$2,156	$779	$1,897	$5,532
-$25.00 to Zone J	$697	$1,569	$789	$1,893	$4,948
+$25.00 to Zone K	$880	$1,855	$809	$1,884	$5,429
-$25.00 to Zone K	$632	$1,855	$777	$1,897	$5,161
+$25.00 to NYCA	$796	$1,855	$810	$2,400	$5,861
-$25.00 to NYCA	$700	$1,855	$779	$1,376	$4,710
+500 MW in Zone G & -500 MW in Zone J	$700	$1,855	$777	$1,898	$5,230
+500 MW in Zone K & -500 MW in Zone J	$700	$1,855	$779	$1,897	$5,231
-500 MW in Zone G & +500 MW in Zone J	$696	$1,855	$792	$1,891	$5,234
-500 MW in Zone K & +500 MW in Zone J	$697	$1,855	$788	$1,893	$5,233

INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY

Sensitivity	Cost of Capacity at Historic Excess for Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
Base Case	$460	$1,007	$251	$687	$2,405
+500 MW to Zone G at G-J EFORd	$462	$1,007	$248	$688	$2,406
-500 MW to Zone G at G-J EFORd	$462	$1,007	$249	$688	$2,406
+500MW to Zone J at J EFORd	$460	$1,007	$251	$687	$2,405
-500MW to Zone J at J EFORd	$460	$1,007	$251	$687	$2,405
+500MW to Zone K at K EFORd	$462	$1,007	$248	$688	$2,406
-500MW to Zone K at K EFORd	$461	$1,007	$251	$687	$2,406
+500MW to Zone F at F EFORd	$461	$1,007	$247	$690	$2,405
-500MW to Zone F at F EFORd	$463	$1,007	$252	$685	$2,407

Sensitivity	Cost of Capacity at Historic Excess for Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
+1000 MW to UPNYSENY	$459	$1,007	$205	$725	$2,396
+$25.00 to G-J	$469	$1,007	$281	$691	$2,448
-$25.00 to G-J	$455	$1,007	$220	$679	$2,362
+$25.00 Zone J	$462	$1,171	$248	$688	$2,569
-$25.00 to Zone J	$460	$844	$251	$687	$2,242
+$25.00 to Zone K	$583	$1,007	$258	$683	$2,531
-$25.00 to Zone K	$344	$1,007	$248	$688	$2,288
+$25.00 to NYCA	$457	$1,007	$266	$871	$2,601
-$25.00 to NYCA	$462	$1,007	$241	$499	$2,209
+500 MW in Zone G & -500 MW in Zone J	$462	$1,007	$248	$688	$2,406
+500 MW in Zone K & -500 MW in Zone J	$462	$1,007	$248	$688	$2,406
-500 MW in Zone G & +500 MW in Zone J	$460	$1,007	$252	$686	$2,406
-500 MW in Zone K & +500 MW in Zone J	$461	$1,007	$251	$687	$2,406

INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY

Change between Current LCR and Optimized with TSL

Sensitivity	Δ Short & Intermediate Term Cost of Capacity from Current LCR to Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
Base Case	$52	-$215	-$26	$0	-$188
+500 MW to Zone G at G-J EFORd	$126	$53	-$139	$0	$39
-500 MW to Zone G at G-J EFORd	$17	-$383	$37	$0	-$329
+500MW to Zone J at J EFORd	$97	-$135	-$43	$0	-$82
-500MW to Zone J at J EFORd	$3	-$37	-$1	$0	-$34
+500MW to Zone K at K EFORd	$0	$5	-$6	$0	-$2
-500MW to Zone K at K EFORd	$177	-$716	-$176	$0	-$715
+500MW to Zone F at F EFORd	$84	-$158	-$74	$0	-$149
-500MW to Zone F at F EFORd	$67	-$222	-$27	$0	-$182

Sensitivity	Δ Short & Intermediate Term Cost of Capacity from Current LCR to Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
+1000 MW to UPNYSENY	$96	$113	-$111	$0	$99
+$25.00 to G-J	$156	-$215	-$89	$0	-$148
-$25.00 to G-J	-$15	-$205	$53	$0	-$167
+$25.00 Zone J	$76	-$249	-$39	$0	-$212
-$25.00 to Zone J	$52	-$157	-$26	$0	-$131
+$25.00 to Zone K	$10	-$215	$14	$0	-$191
-$25.00 to Zone K	$41	-$215	-$41	$0	-$215
+$25.00 to NYCA	$5	-$215	$10	$0	-$200
-$25.00 to NYCA	$75	-$215	-$48	$0	-$187
+500 MW in Zone G & -500 MW in Zone J	$81	$156	-$192	$0	$44
+500 MW in Zone K & -500 MW in Zone J	$0	$122	$25	$0	$147
-500 MW in Zone G & +500 MW in Zone J	$49	-$243	$9	$0	-$185
-500 MW in Zone K & +500 MW in Zone J	$196	-$649	-$162	$0	-$616

NEW YORK INDEPENDENT SYSTEM OPERATOR

Sensitivity	Δ Cost of Capacity at LOE from Current LCR to Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
Base Case	$8	-$32	$7	$5	-$12
+500 MW to Zone G at G-J EFORd	$18	$8	-$90	$41	-$23
-500 MW to Zone G at G-J EFORd	$3	-$88	$78	-$11	-$18
+500MW to Zone J at J EFORd	$14	-$46	$2	$11	-$20
-500MW to Zone J at J EFORd	$1	-$6	$4	$0	-$2
+500MW to Zone K at K EFORd	$1	$1	-$3	$1	-$1
-500MW to Zone K at K EFORd	$30	-$112	$0	$32	-$51
+500MW to Zone F at F EFORd	$12	-$23	-$12	$10	-$14
-500MW to Zone F at F EFORd	$11	-$36	$5	$6	-$14

Sensitivity	Δ Cost of Capacity at LOE from Current LCR to Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
+1000 MW to UPNYSENY	$16	$20	-$153	$78	-$40
+$25.00 to G-J	$23	-$32	-$31	$15	-$24
-$25.00 to G-J	-$2	-$32	$38	-$14	-$10
+$25.00 Zone J	$11	-$36	-$3	$9	-$19
-$25.00 to Zone J	$8	-$24	$7	$5	-$4
+$25.00 to Zone K	$1	-$32	$28	-$4	-$7
-$25.00 to Zone K	$8	-$32	-$5	$9	-$19
+$25.00 to NYCA	$1	-$32	$28	-$5	-$8
-$25.00 to NYCA	$11	-$32	-$3	$6	-$17
+500 MW in Zone G & -500 MW in Zone J	$12	$24	-$94	$40	-$18
+500 MW in Zone K & -500 MW in Zone J	-$9	$19	-$5	$1	$6
-500 MW in Zone G & +500 MW in Zone J	$7	-$110	$89	-$10	-$25
-500 MW in Zone K & +500 MW in Zone J	$33	-$138	-$2	$43	-$64

NEW YORK INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY

Sensitivity	Δ Cost of Capacity at Historic Excess from Current LCR to Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
Base Case	$4	-$15	$2	$2	-$7
+500 MW to Zone G at G-J EFORd	$10	$4	-$27	$16	$2
-500 MW to Zone G at G-J EFORd	$1	-$42	$24	-$4	-$21
+500MW to Zone J at J EFORd	$7	-$22	$1	$4	-$10
-500MW to Zone J at J EFORd	$0	-$3	$1	$0	-$1
+500MW to Zone K at K EFORd	$0	$0	-$1	$1	$0
-500MW to Zone K at K EFORd	$16	-$54	$1	$12	-$25
+500MW to Zone F at F EFORd	$7	-$11	-$3	$4	-$4
-500MW to Zone F at F EFORd	$6	-$17	$2	$2	-$7

NEW YORK INDEPENDENT SYSTEM OPERATOR

Sensitivity	Δ Cost of Capacity at Historic Excess from Current LCR to Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
+1000 MW to UPNYSENY	$8	$10	-$47	$30	$1
+$25.00 to G-J	$12	-$15	-$9	$6	-$6
-$25.00 to G-J	-$1	-$15	$12	-$5	-$10
+$25.00 Zone J	$6	-$18	-$1	$3	-$9
-$25.00 to Zone J	$4	-$13	$2	$2	-$5
+$25.00 to Zone K	$1	-$15	$9	-$2	-$7
-$25.00 to Zone K	$5	-$15	-$1	$4	-$8
+$25.00 to NYCA	$1	-$15	$9	-$2	-$8
-$25.00 to NYCA	$6	-$15	-$1	$2	-$7
+500 MW in Zone G & -500 MW in Zone J	$6	$12	-$28	$15	$5
+500 MW in Zone K & -500 MW in Zone J	-$5	$9	-$2	$0	$3
-500 MW in Zone G & +500 MW in Zone J	$4	-$53	$27	-$4	-$26
-500 MW in Zone K & +500 MW in Zone J	$17	-$66	$0	$17	-$32

NEW YORK INDEPENDENT SYSTEM OPERATOR

Appendix

Consumer Impact Analysis: Alternative Methods for Determining LCRs

Tariq N. Niazi
Senior Manager, Consumer Interest Liaison

Installed Capacity Working Group

October 11, 2017

Agenda

- Project Objective
- Background
- Cost Impacts
- Additional Factors
- Other Impacts
- Feedback
- Next Steps

Project Objective for Determining Alternative LCRs

- Evaluate an alternative methodology for determining LCRs based on economic optimization that minimizes the cost of satisfying planning requirements
  - Identify LCRs that provide the least cost distribution of capacity resources amongst NYCA Localities while keeping LOLE<0.1

NEW YORK INDEPENDENT SYSTEM OPERATOR

Background

- The NYISO started this project by first establishing guiding principles (least cost, stable, robust, predictable)
- Next, the proof of concept phase demonstrated how the alternative LCR methodology performs in relation to the guiding principles
- This was followed by Phase 2, which focused on refining the methodology to ensure that optimization is based on sound market and engineering principles
- Phase 3 will focus on simulating market situations to demonstrate the performance of the alternative methodology

NEW YORK INDEPENDENT SYSTEM OPERATOR

Consumer Impact Analysis (IA) Evaluation Areas

- Present the potential impact on all four evaluation areas

RELIABILITY

COST IMPACT/
MARKET EFFICIENCIES

ENVIRONMENT/
NEW TECHNOLOGY

TRANSPARENCY

NEW YORK INDEPENDENT SYSTEM OPERATOR

Cost Impact Methodology

- The impact analysis compares the cost impacts on consumers in each of the three Localities (J, K, G-J) and NYCA of the alternative LCR methodology with the current methodology for the, short term, intermediate, and long term
- The base case and the sensitivity cases referenced herein are the same as those presented to stakeholders
  - The cost impact analysis utilizes the results produced after all refinements were incorporated into the methodology (*i.e.*, final methodology)
- The 2017/2018 Capability Year LCR base case was solved to an LOLE of 0.1 days/year while using the NYCA Minimum Installed Capacity Requirement

NEW YORK INDEPENDENT SYSTEM OPERATOR

Consumer Impact Assumptions

- **Load**
  - Equivalent to the peak load in the MARS case
- **Reference Point**
  - Current values, except when sensitivity assumed a change in Net CONE
- **Derating Factor**
  - Historical values
- **Supply**
  - **Short Term:** Current generation with assumed values for imports, exports, unsold, and unoffered based on historical levels
  - **Intermediate Term:** Same as short term except with the removal or addition of the generation assumed in the sensitivity
  - **Level of Excess:** Supply level is equal to the LCR/IRM plus the assumed level of excess defined in the Demand Curve Reset
  - **Historical Percentage Excess:** Supply level is equal to the historic excess defined as a percentage of excess above the requirement observed within the last 3 Capability Years in each of the different Localities

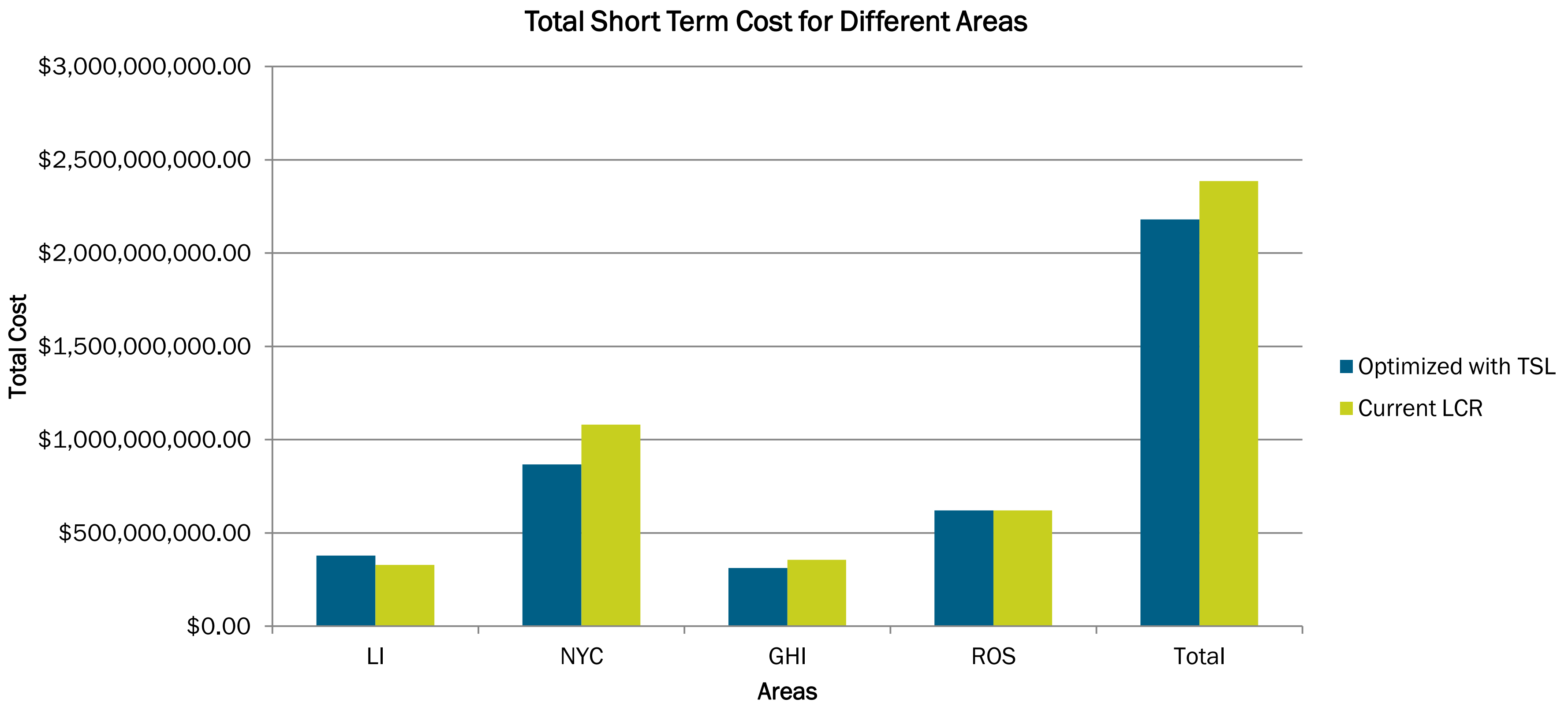
Consumer Costs in the Short & Intermediate Term

Short Term Cost Impact Methodology

- The short term impact compares the cost of applying the current methodology and the alternative methodology to the 2017/2018 Capability Year LCR base case
  - The short-run impact analysis assumes no changes to generation and transmission

Scenario	Optimized Costs ($)			Current LCR Methodology Costs ($)		
	As found	At Level of Excess	At Generic excess level	As found	At Level of Excess	At Generic excess level
Base Case						
+500 MW in G						
-500 MW in G						

Difference in cost is short run impact (as found system and assumes no changes)



TSL = Transmission Security Limits

NEW YORK INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY

Intermediate Cost Impact Methodology

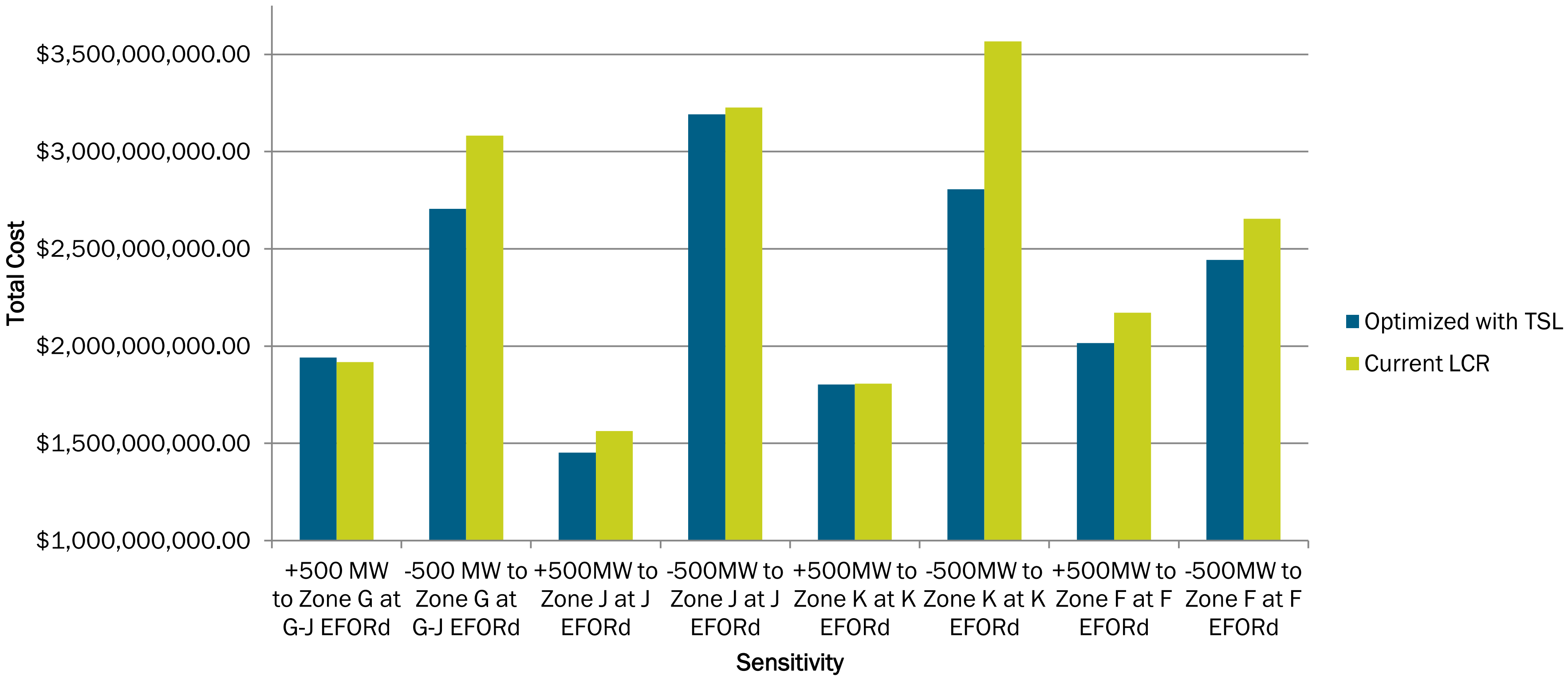
- The intermediate impact compares the cost of applying the current LCR methodology with the alternative methodology as generation and transmission resources change
  - This analysis assumes the only change to the system is the change used to perform the sensitivity case
  - For example, the cost impact of a +500 MW Zone J sensitivity case would keep all assumptions constant except for the addition of 500 MW to Zone J
- The intermediate impact was performed on a sub-set of simple sensitivity cases along with a set of sensitivities that include multiple changes to the system
- Sensitivities were also performed for changes in net CONE

NEW YORK INDEPENDENT SYSTEM OPERATOR

Scenario	Optimized Costs ($)			Current LCR Methodology Costs ($)		
	As found	At Level of Excess	At Generic excess level	As found	At Level of Excess	At Generic excess level
Base Case						
+500 MW in G						
- 500 MW in G						

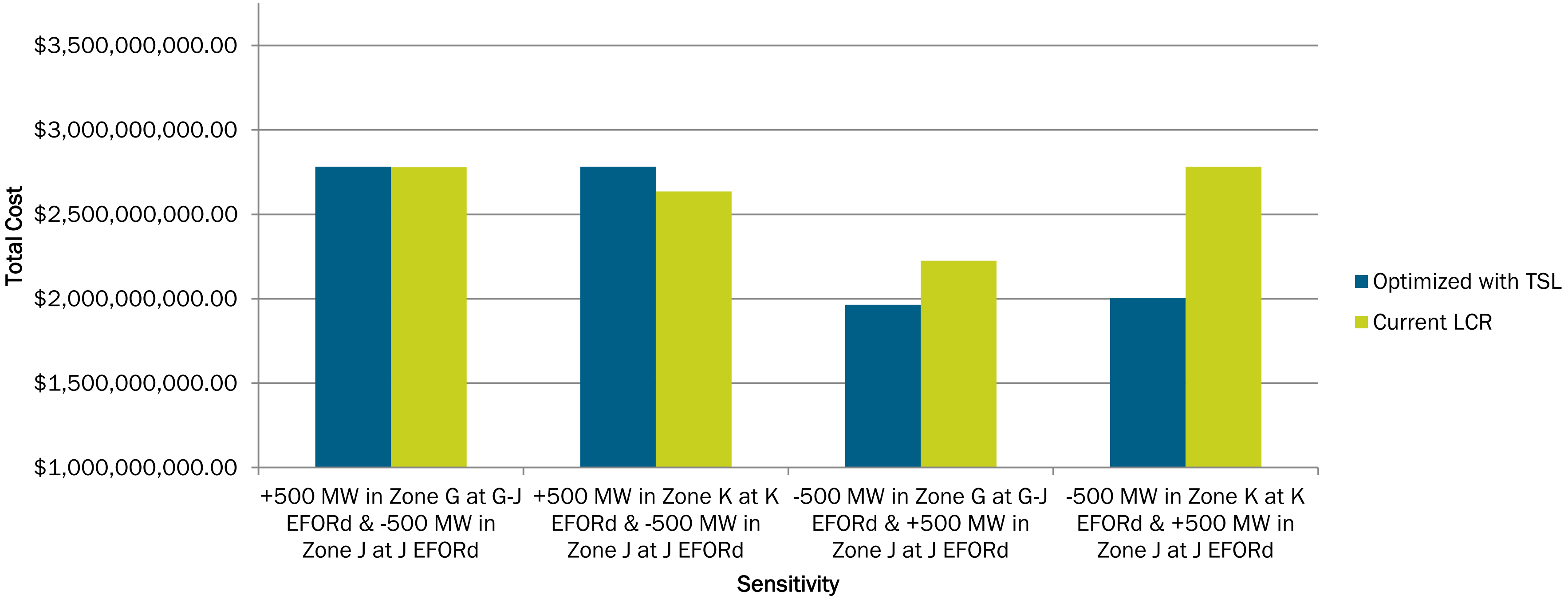
Difference in cost is intermediate impact (as found system with an addition and subtraction of 500 MW to G)

Total Intermediate Term Cost for the NYCA (Change in Generation)



DRAFT – FOR DISCUSSION PURPOSES ONLY

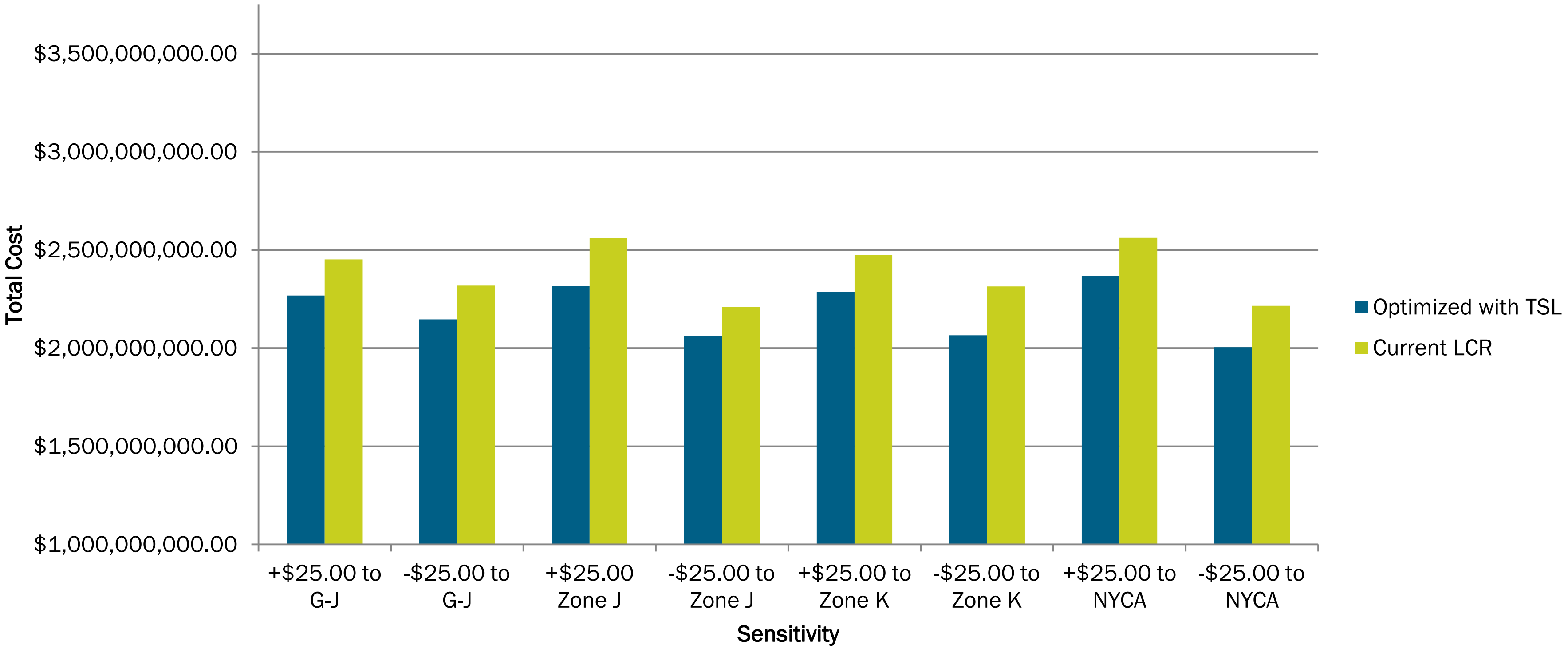
Total Intermediate Term Cost for NYCA (Multiple Changes in Generation)



NEW YORK INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY

Total Intermediate Term Cost for NYCA (Change in Net CONE)



NEW YORK INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY

Sensitivity	Δ Short & Intermediate Term Costs from Current LCR to Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
Base Case	$51.11	-$212.66	-$44.33	$0.00	-$205.88
+500 MW to Zone G at G-J EFORd	$125.27	$51.96	-$153.43	$0.00	$23.81
-500 MW to Zone G at G-J EFORd	$17.39	-$431.24	$36.33	$0.00	-$377.53
+500MW to Zone J at J EFORd	$95.83	-$163.15	-$42.96	$0.00	-$110.28
-500MW to Zone J at J EFORd	$2.84	-$35.90	-$1.17	$0.00	-$34.24
+500MW to Zone K at K EFORd	$0.00	$4.77	-$8.51	$0.00	-$3.74
-500MW to Zone K at K EFORd	$176.11	-$726.29	-$210.43	$0.00	-$760.61
+500MW to Zone F at F EFORd	$83.41	-$156.50	-$82.52	$0.00	-$155.62
-500MW to Zone F at F EFORd	$73.11	-$239.52	-$46.42	$0.00	-$212.83

NEW YORK INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY

Sensitivity	Δ Short & Intermediate Term Costs from Current LCR to Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
+1000 MW to UPNYSENY	$107.88	$142.14	-$110.75	$0.00	$139.28
+$25.00 to G-J	$155.10	-$212.66	-$126.83	$0.00	-$184.39
-$25.00 to G-J	-$15.26	-$212.66	$55.22	$0.00	-$172.69
+$25.00 Zone J	$74.53	-$246.68	-$73.12	$0.00	-$245.26
-$25.00 to Zone J	$51.11	-$155.60	-$44.33	$0.00	-$148.82
+$25.00 to Zone K	$10.29	-$212.66	$13.82	$0.00	-$188.54
-$25.00 to Zone K	$40.66	-$212.66	-$76.86	$0.00	-$248.85
+$25.00 to NYCA	$4.37	-$212.66	$14.68	$0.00	-$193.60
-$25.00 to NYCA	$74.17	-$212.66	-$71.94	$0.00	-$210.43
+500 MW in Zone G & -500 MW in Zone J	$79.84	$154.57	-$230.94	$0.00	$3.47
+500 MW in Zone K & -500 MW in Zone J	$0.00	$120.91	$25.27	$0.00	$146.17
-500 MW in Zone G & +500 MW in Zone J	$48.98	-$329.79	$20.31	$0.00	-$260.50
-500 MW in Zone K & +500 MW in Zone J	$194.48	-$776.11	-$197.59	$0.00	-$779.23

NEW YORK INDEPENDENT SYSTEM OPERATOR

	Δ Short & Intermediate Term Costs from Current LCR to Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
Minimum	-$15.26	-$776.11	-$230.94	$0.00	-$779.23
25th percentile	$12.07	-$232.80	-$103.69	$0.00	-$237.15
Average	$65.96	-$194.32	-$61.66	$0.00	-$190.01
75th percentile	$92.72	-$65.82	$10.07	$0.00	-$53.25
Maximum	$194.48	$154.57	$55.22	$0.00	$146.17

NEW YORK INDEPENDENT SYSTEM OPERATOR

Short & Intermediate Term Consumer Impacts

- Based on the sensitivities conducted, total NYCA consumer cost is reduced in the majority of cases
  - The only cases that do not result in savings occur when the current LCR methodology results in a Zone J LCR lower than the Transmission Security Floor used in the optimization
- The average benefit from the Optimized LCR methodology with TSL compared to the Current LCR methodology is approximately $190 million

Consumer Costs at Level of Excess (LOE)

Long Term Cost Impact Methodology

- **The long term cost impact compares the cost of the current LCR methodology with the alternative methodology at long-run equilibrium**
  - The long-run equilibrium was modeled at the Level of Excess condition (Defined in the Demand Curve reset), and also
  - Historic excess defined as a percentage of excess above the requirement observed within the last 3 Capability Years in each of the different Localities

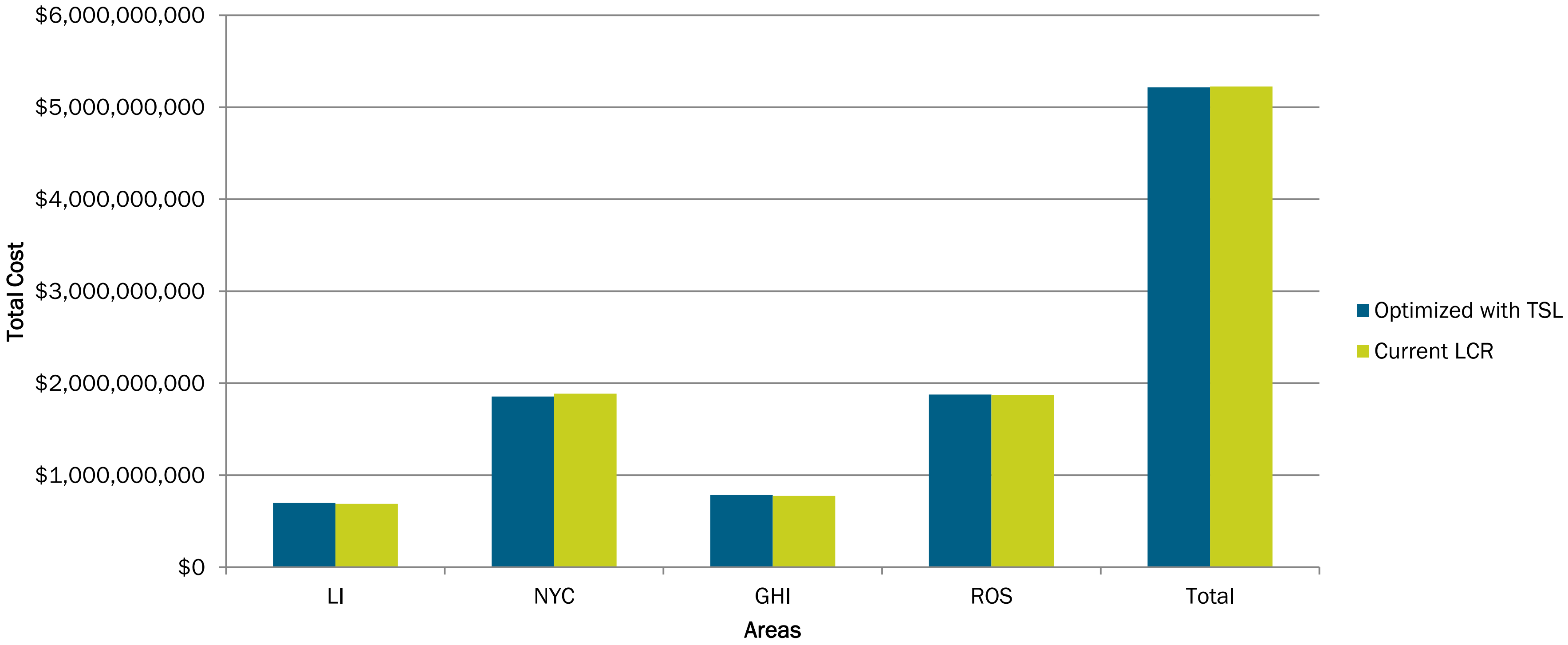
NEW YORK INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY

Scenario	Optimized Costs ($)			Current LCR Methodology Costs ($)		
	As found	At Level of Excess	At Generic excess level	As found	At Level of Excess	At Generic excess level
Base Case						
+500 MW in G						
-500 MW in G						

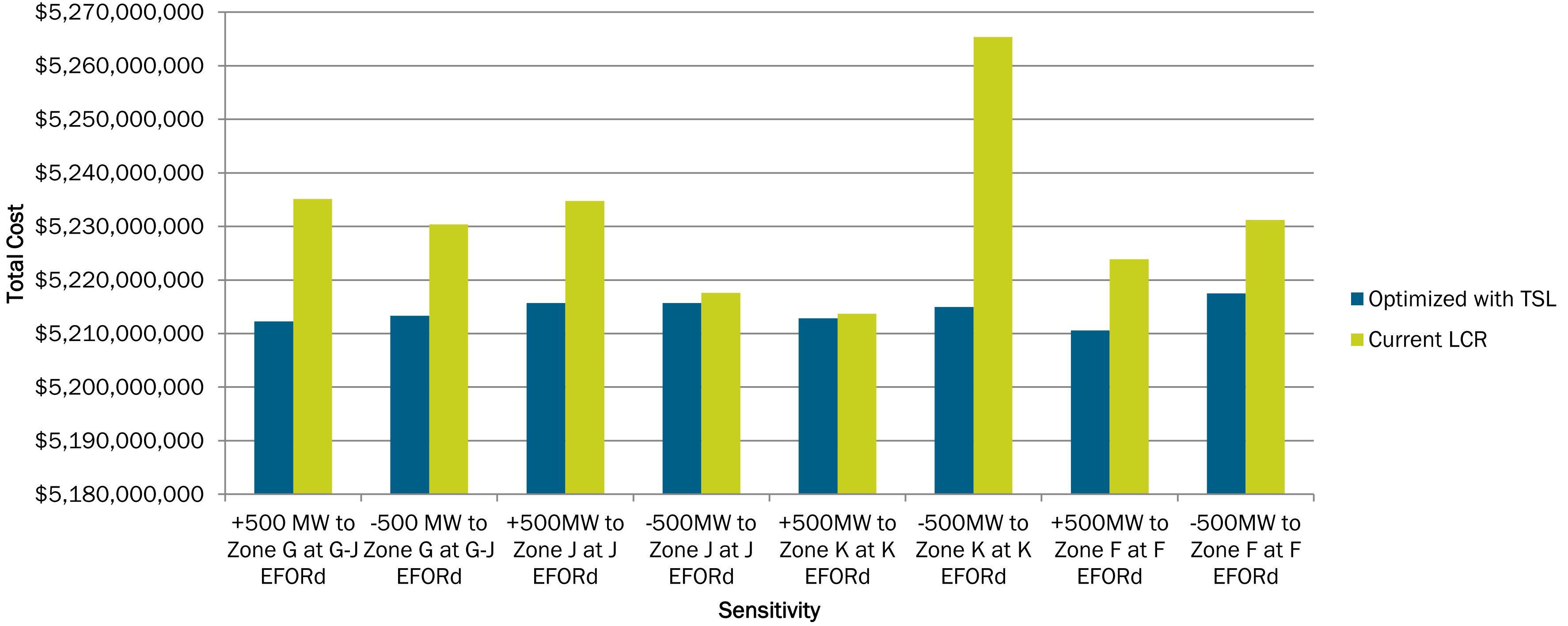
Difference in cost is long term impact (at LOE)

Total Long Term Cost at LOE for Different Areas



NEW YORK INDEPENDENT SYSTEM OPERATOR

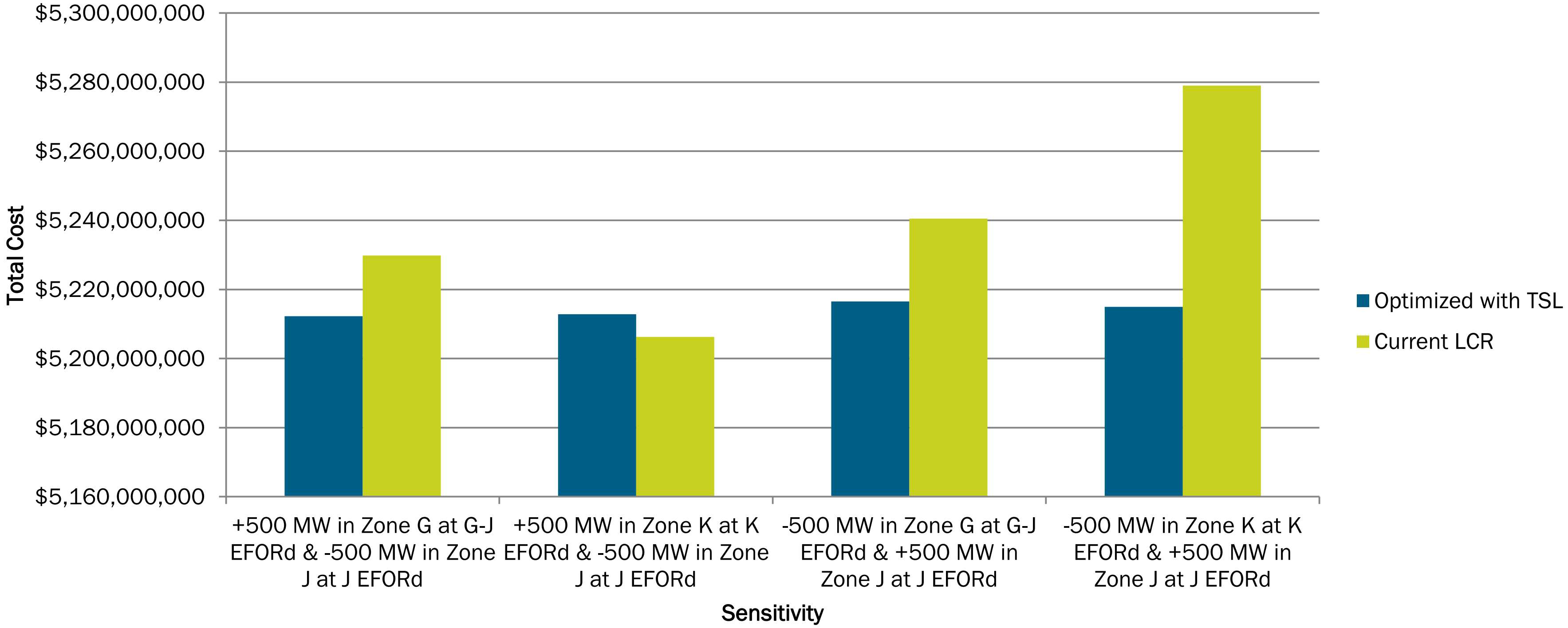
Total Long Term Cost at LOE for NYCA (Change in Generation)



NEW YORK INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY

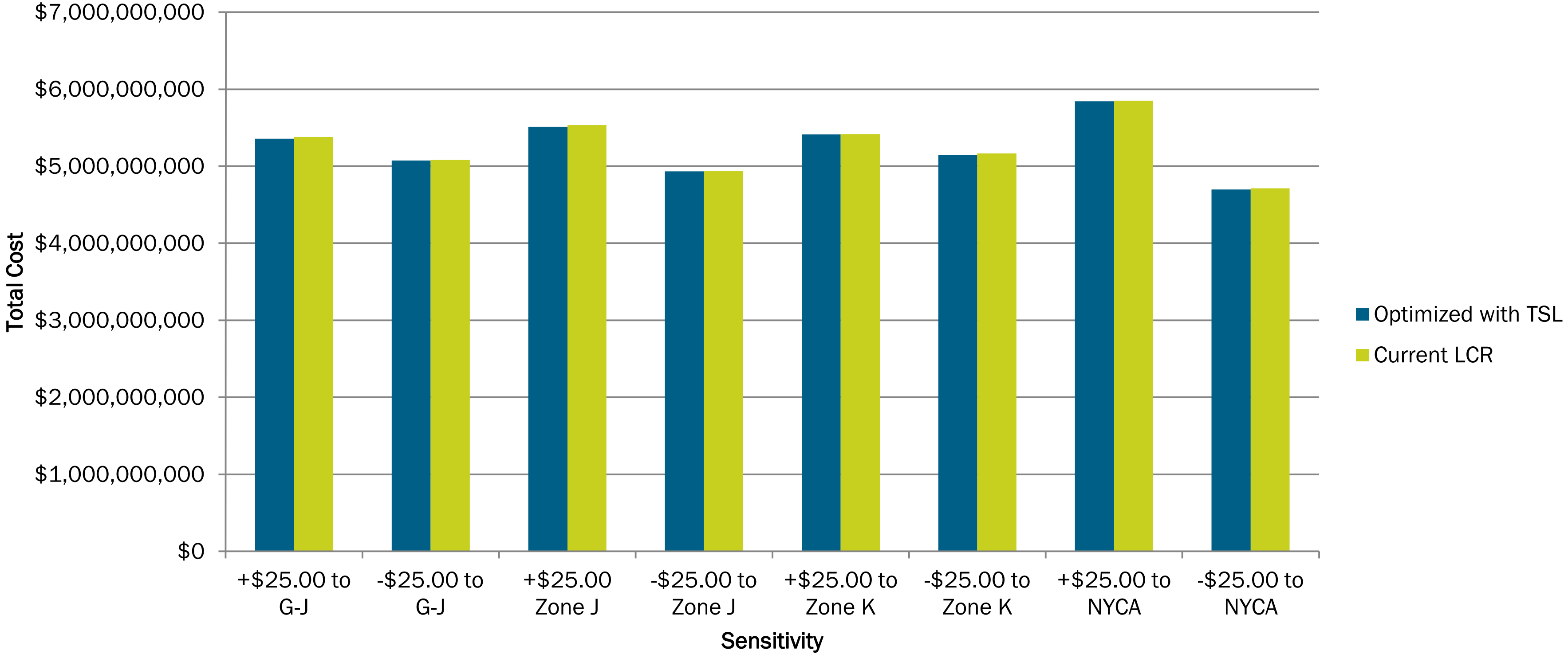
Total Long Term Cost at LOE for NYCA (Multiple Changes in Generation)



NEW YORK INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY

Total Long Term Cost at LOE for NYCA (Change in Net CONE)



NEW YORK INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY

Sensitivity	Δ Cost at LOE from Current LCR to Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
Base Case	$7.80	-$31.74	$7.56	$4.70	-$11.68
+500 MW to Zone G at G-J EFORd	$18.04	$7.60	-$89.40	$40.91	-$22.85
-500 MW to Zone G at G-J EFORd	$2.65	-$87.49	$78.69	-$10.92	-$17.06
+500MW to Zone J at J EFORd	$14.05	-$45.76	$1.64	$11.01	-$19.06
-500MW to Zone J at J EFORd	$0.36	-$6.07	$3.85	-$0.09	-$1.94
+500MW to Zone K at K EFORd	$0.60	$0.57	-$3.40	$1.39	-$0.84
-500MW to Zone K at K EFORd	$29.82	-$111.71	-$0.43	$31.91	-$50.42
+500MW to Zone F at F EFORd	$12.04	-$23.40	-$11.86	$9.91	-$13.31
-500MW to Zone F at F EFORd	$10.33	-$35.26	$5.28	$5.89	-$13.75

NEW YORK INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY

Sensitivity	Δ Cost at LOE from Current LCR to Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
+1000 MW to UPNYSENY	$15.88	$21.00	-$153.53	$77.85	-$38.80
+$25.00 to G-J	$23.24	-$31.87	-$30.80	$15.18	-$24.26
-$25.00 to G-J	-$2.33	-$31.74	$38.48	-$14.01	-$9.60
+$25.00 Zone J	$11.17	-$36.17	-$2.65	$8.66	-$18.98
-$25.00 to Zone J	$7.80	-$24.26	$7.56	$4.70	-$4.20
+$25.00 to Zone K	$1.15	-$31.74	$27.86	-$3.94	-$6.67
-$25.00 to Zone K	$8.50	-$31.74	-$4.64	$9.22	-$18.66
+$25.00 to NYCA	$1.08	-$31.74	$28.20	-$5.34	-$7.80
-$25.00 to NYCA	$11.09	-$31.74	-$2.32	$6.18	-$16.79
+500 MW in Zone G & -500 MW in Zone J	$11.71	$24.44	-$94.00	$40.27	-$17.58
+500 MW in Zone K & -500 MW in Zone J	-$8.89	$19.91	-$4.83	$0.43	$6.61
-500 MW in Zone G & +500 MW in Zone J	$7.48	-$110.46	$89.00	-$10.00	-$23.98
-500 MW in Zone K & +500 MW in Zone J	$32.71	-$138.07	-$1.89	$43.22	-$64.04

NEW YORK INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY

	Δ Cost at LOE from Current LCR to Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
Minimum	-$8.89	-$138.07	-$153.53	-$14.01	-$64.04
25th percentile	$1.53	-$35.94	-$4.79	$0.04	-$21.90
Average	$9.83	-$34.88	-$5.07	$12.14	-$17.98
75th percentile	$13.55	-$10.40	$7.56	$14.14	-$8.25
Maximum	$32.71	$24.44	$89.00	$77.85	$6.61

NEW YORK INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY

Long Term Consumer Impacts at Level of Excess

- **Based on the sensitivities conducted, total long term NYCA consumer cost at the LOE is reduced in all cases, except one**
  - The only case that did not result in savings occurs when the current LCR methodology results in a Zone J LCR lower than the Transmission Security Floor used in the optimization
- **Consumer savings in the long term are smaller than the short term savings since the difference in the quantity of capacity purchased for each Locality is minimal between the current LCR methodology and the optimization while the price stays relatively stable**

NEW YORK INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY

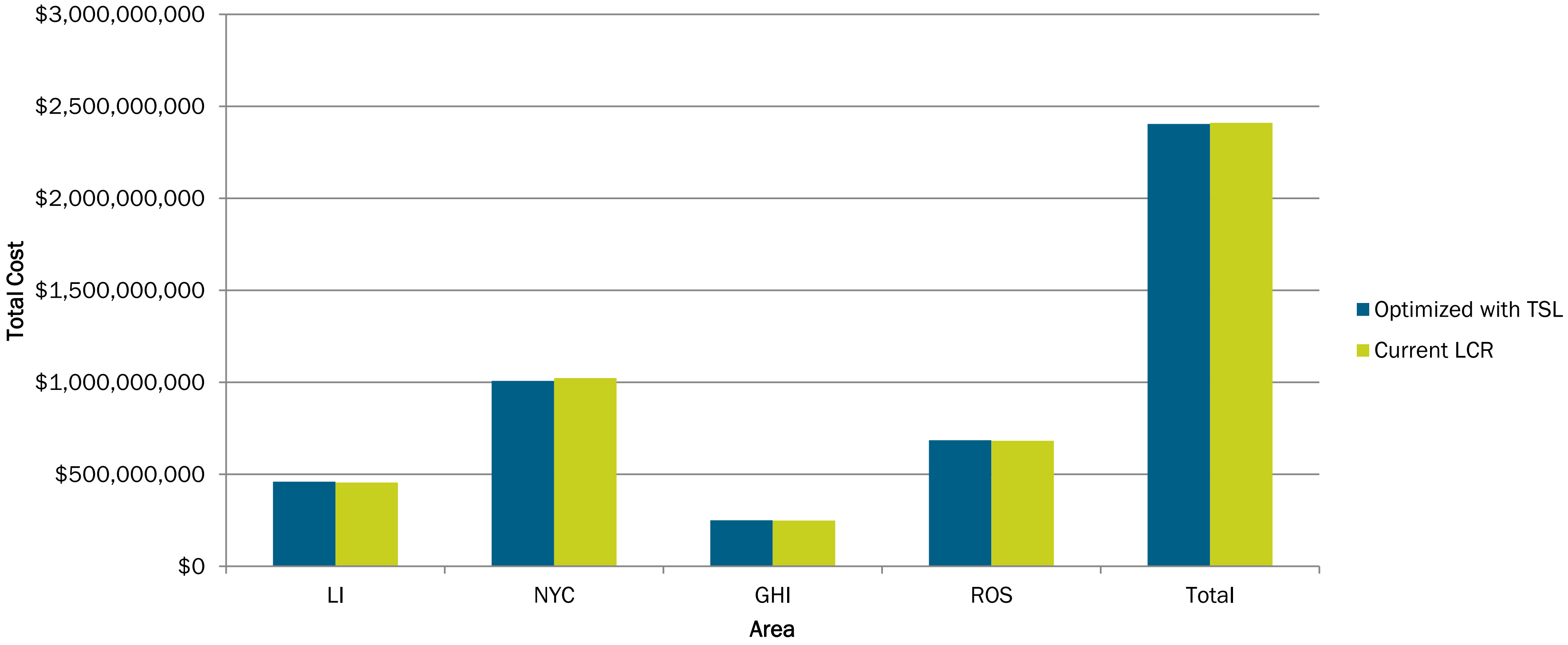
Consumer Costs at Historic Percentage Excess

Scenario	Optimized Costs ($)			Current LCR Methodology Costs ($)		
	As found	At Level of Excess	At Generic excess level	As found	At Level of Excess	At Generic excess level
Base Case						
+500 MW in G						
-500 MW in G						

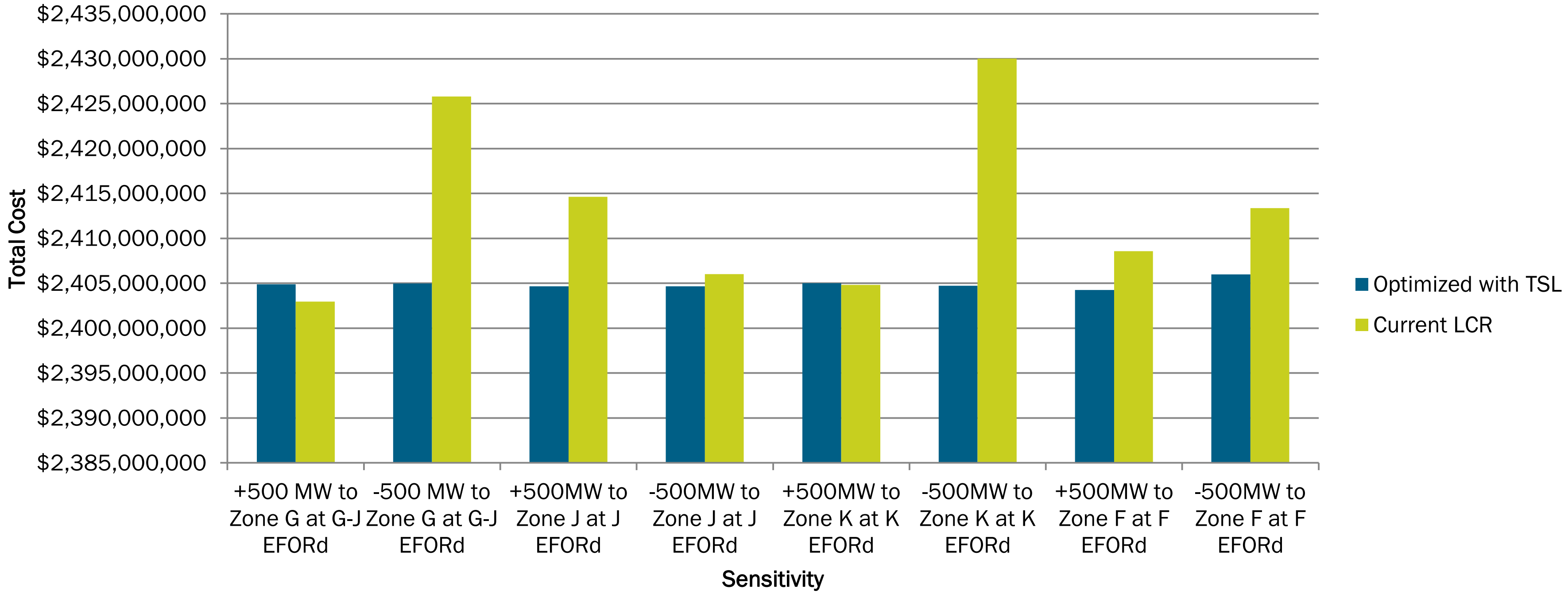
Difference in cost is long term impact (at generic excess)

DRAFT – FOR DISCUSSION PURPOSES ONLY

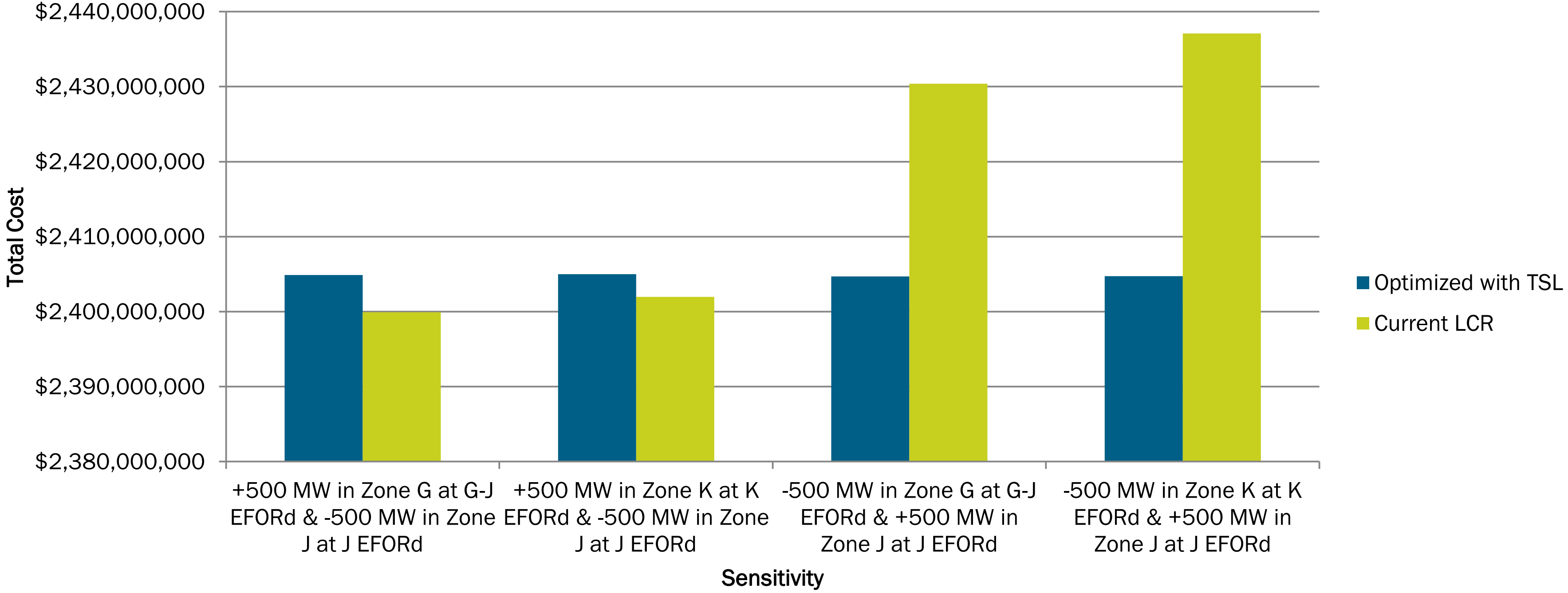
Total Long Term Cost at Historic Excess for Different Areas



Total Long Term Cost at Historic Percentage Excess Level for NYCA (Change in Generation)



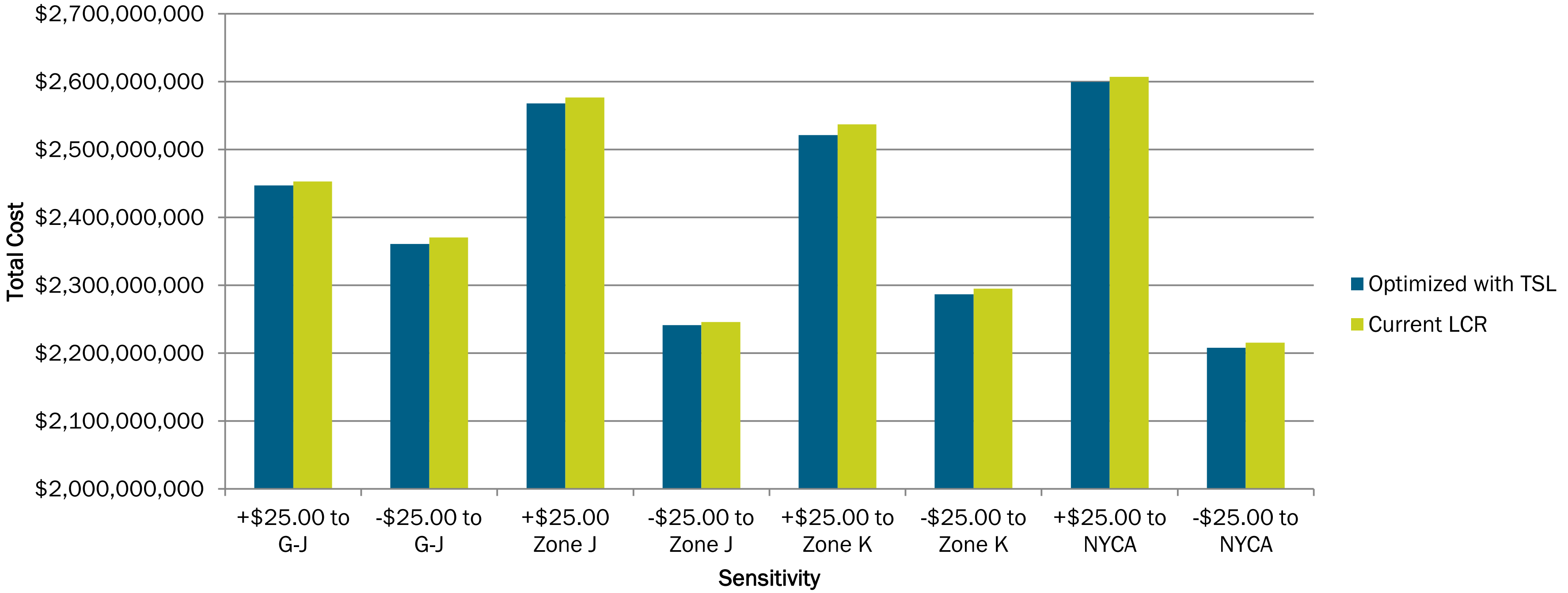
Total Long Term Cost at Historic Percentage Excess Level for NYCA (Multiple Changes in Generation)



NEW YORK INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY

Total Long Term Cost at Historic Percentage Excess Level for NYCA (Change in Net CONE)



NEW YORK INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY

Sensitivity	Δ Cost at Historic Excess from Current LCR to Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
Base Case	$3.99	-$15.16	$2.45	$1.81	-$6.91
+500 MW to Zone G at G-J EFORd	$9.68	$3.62	-$27.06	$15.70	$1.93
-500 MW to Zone G at G-J EFORd	$1.36	-$42.27	$24.27	-$4.17	-$20.82
+500MW to Zone J at J EFORd	$7.39	-$22.32	$0.73	$4.24	-$9.96
-500MW to Zone J at J EFORd	$0.25	-$2.76	$1.19	-$0.03	-$1.35
+500MW to Zone K at K EFORd	$0.41	$0.32	-$1.06	$0.53	$0.20
-500MW to Zone K at K EFORd	$15.60	-$53.74	$0.58	$12.27	-$25.29
+500MW to Zone F at F EFORd	$6.46	-$11.15	-$3.44	$3.82	-$4.32
-500MW to Zone F at F EFORd	$5.73	-$17.11	$1.73	$2.28	-$7.38

Sensitivity	Δ Cost at Historic Excess from Current LCR to Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
+1000 MW to UPNYSENY	$8.22	$9.86	-$46.53	$29.83	$1.37
+$25.00 to G-J	$12.26	-$15.16	-$8.93	$5.86	-$5.98
-$25.00 to G-J	-$1.15	-$15.16	$12.10	-$5.37	-$9.58
+$25.00 Zone J	$5.85	-$17.61	-$0.58	$3.34	-$9.01
-$25.00 to Zone J	$3.99	-$12.71	$2.45	$1.81	-$4.45
+$25.00 to Zone K	$7.35	-$41.02	$25.70	-$8.02	-$16.00
-$25.00 to Zone K	$4.78	-$15.16	-$1.20	$3.55	-$8.03
+$25.00 to NYCA	$0.64	-$15.16	$9.03	-$2.04	-$7.54
-$25.00 to NYCA	$5.80	-$15.16	-$0.46	$2.38	-$7.45
+500 MW in Zone G & -500 MW in Zone J	$6.22	$11.77	-$28.45	$15.44	$4.98
+500 MW in Zone K & -500 MW in Zone J	-$4.71	$9.25	-$1.63	$0.15	$3.06
-500 MW in Zone G & +500 MW in Zone J	$3.78	-$53.05	$27.42	-$3.81	-$25.67
-500 MW in Zone K & +500 MW in Zone J	$17.16	-$66.35	$0.22	$16.61	-$32.36

NEW YORK INDEPENDENT SYSTEM OPERATOR

	Δ Cost at Historic Excess from Current LCR to Optimized with TSL (million $)				
	LI	NYC	GHI	ROS	Total
Minimum	-$4.71	-$66.35	-$46.53	-$8.02	-$32.36
25th percentile	$1.97	-$21.14	-$1.53	$0.01	-$9.86
Average	$5.50	-$18.01	-$0.52	$4.37	-$8.66
75th percentile	$7.38	-$4.86	$2.45	$5.45	-$2.10
Maximum	$17.16	$11.77	$27.42	$29.83	$4.98

NEW YORK INDEPENDENT SYSTEM OPERATOR

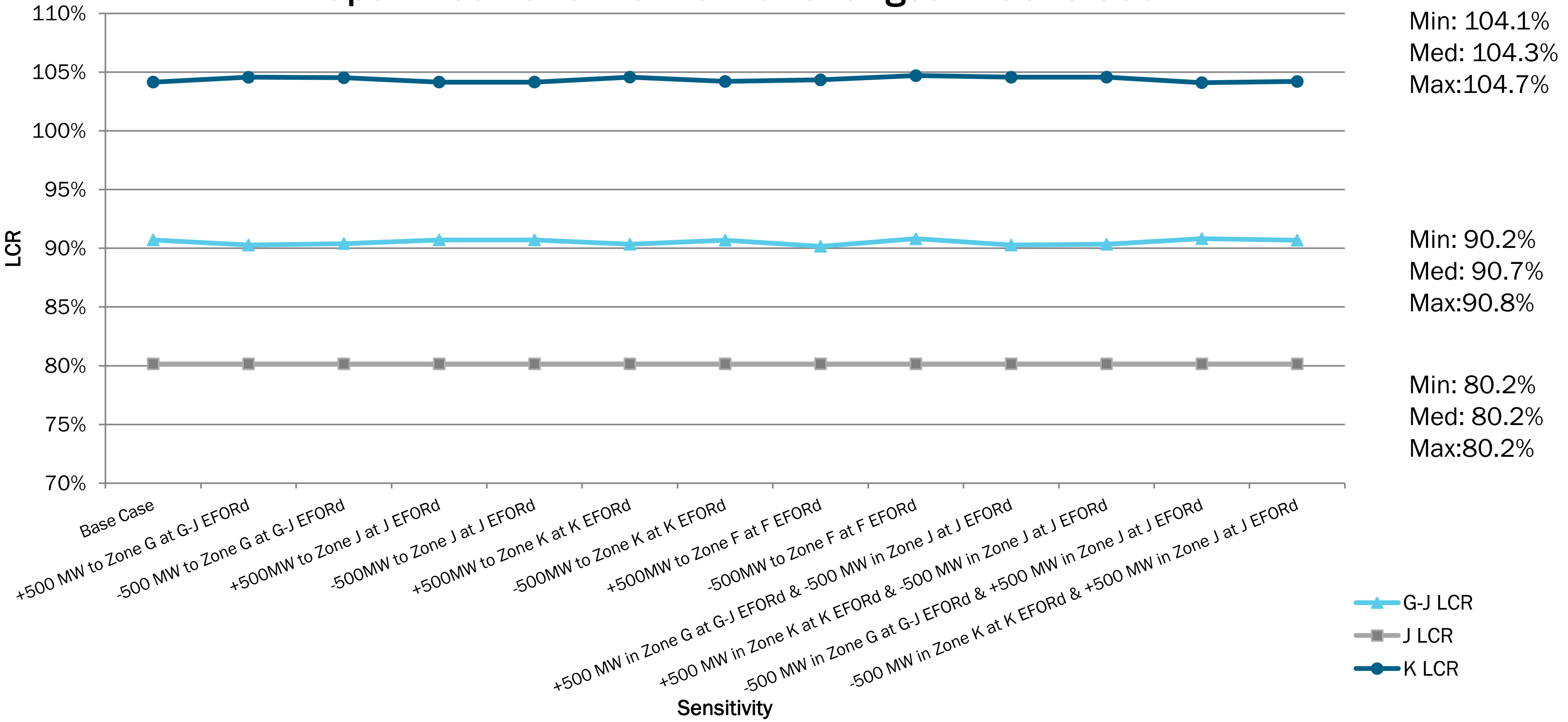
DRAFT – FOR DISCUSSION PURPOSES ONLY

Long Term Consumer Cost Impacts at Historic Excess

- **Based on the sensitivities conducted, total long term NYCA consumer cost at historic excess is reduced in the majority of cases**
  - The only cases that do not result in savings occur when the current LCR methodology results in a Zone J LCR lower than the Transmission Security Floor used in the optimization

Additional Factors

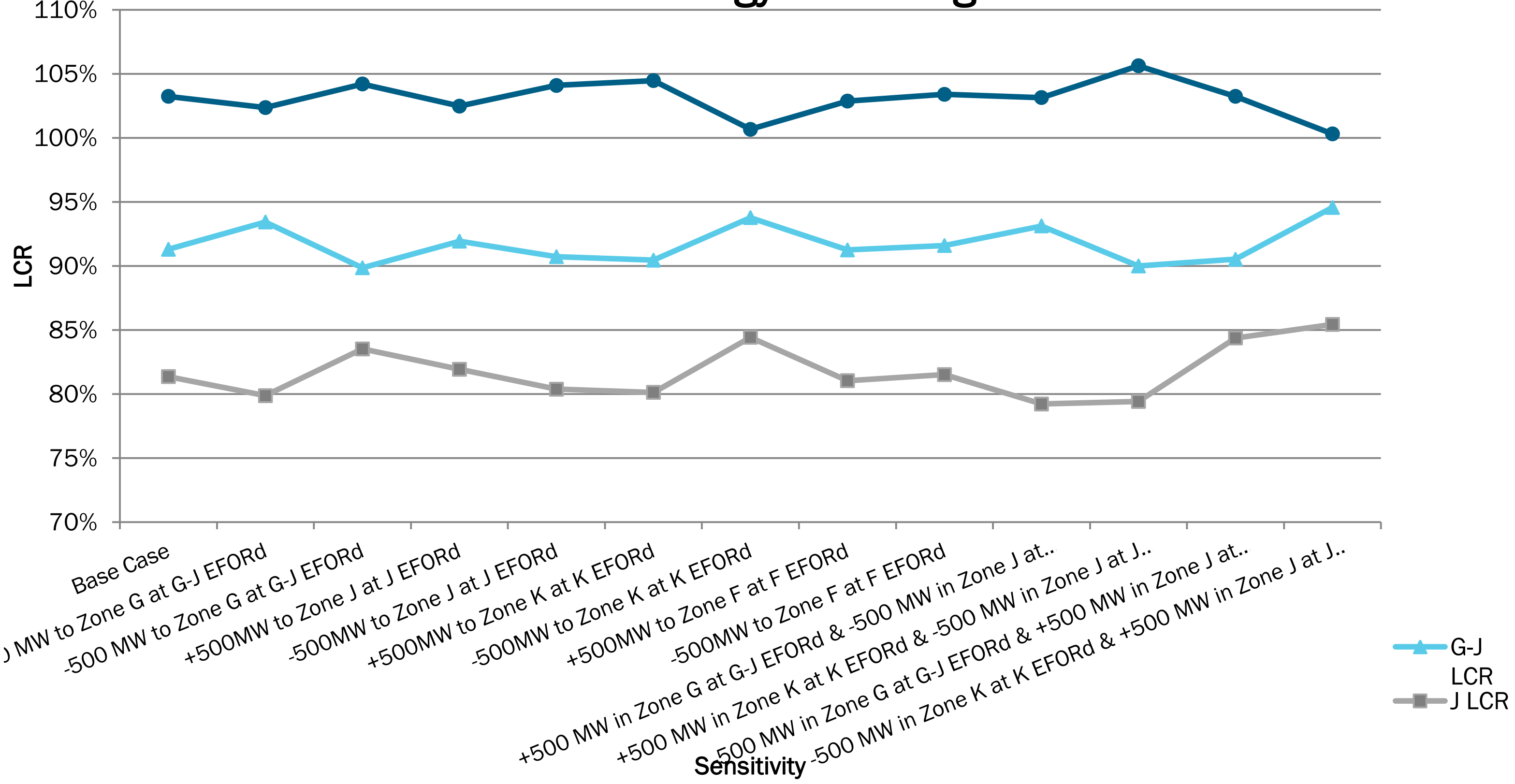
Optimized LCRs with TSL for Changes in Generation



NEW YORK INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY

Current LCRs Methodology for Changes in Generation



Min: 100.3%
Med: 103.3%
Max:105.6%

Min: 89.9%
Med: 91.3%
Max:94.6%

Min: 79.2%
Med: 81.4%
Max:85.4%

DRAFT – FOR DISCUSSION PURPOSES ONLY

Stability of LCRs

- The optimization methodology results in an increase in stability as generation changes occur within the system

Methodology	Range of LCRs		
	Zone K	Zone J	G-J
Current LCR Methodology	5.3%	6.2%	4.7%
Optimized with TSL	0.6%	0.0%	0.7%

NEW YORK INDEPENDENT SYSTEM OPERATOR

Stability of LCRs

Methodology	Range of LCRs		
	Zone K	Zone J	G-J
Current LCR Methodology	289 MW	725 MW	756 MW
Optimized with TSL	32 MW	0 MW	104 MW

Other Impacts

Reliability Impact

- The alternate LCR methodology results in more stable and efficient LCRs than the current LCR methodology
- The increase in stability should improve market signals
- Stable and predictable market signals will lead to more efficient decisions in expanding and retiring assets, hence improving reliability
- Transmission Security Limits (TSL) further ensure that reliability is maintained at all times

NEW YORK INDEPENDENT SYSTEM OPERATOR

Environmental Impact

- No change expected

Impact on Transparency

- More stable LCRs should enhance transparency as market response to changes in generation and/or reference prices will be more predictable than under the current LCR methodology

Feedback?

- Email additional feedback to:
- deckels@nyiso.com

Questions?

We are here to help. Let us know if we can add anything.

The Mission of the New York Independent System Operator, in collaboration with its stakeholders, is to serve the public interest and provide benefits to consumers by:

- Maintaining and enhancing regional reliability
- Operating open, fair and competitive wholesale electricity markets
- Planning the power system for the future
- Providing factual information to policy makers, stakeholders and investors in the power system

www.nyiso.com

NEW YORK INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY

Exhibit 30

Alternative Methods for Determining LCRs: Final Market Design

Zachary Stines

Associate Market Design Specialist

Business Issues Committee

November 15, 2017, NYISO

NEW YORK INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY

Agenda

- **2017 Project**
- **Final Market Design**
  - Design Objective
  - Methodology
  - Results
  - Cost Allocation
  - Timeline
- **Next Steps**
  - 2018 Project Scope
- **Questions**
- **Propose for vote as guidance for 2018 efforts**
- **Appendix**

2017 Project Presentations

2017 ICAPWG Presentations

Date	Discussion points and links to materials
2-15-17	Recap of 2016 Effort, 2017 Plan, and Current Status
4-04-17	2017 Commitment and Base Case
5-11-17	Proof of Concept and Refining Methodology
6-01-17	Sensitivities and Cost Curves
6-29-17	Sensitivity Results and Refining Methodology
7-25-17	Refining Methodology
8-22-17	Refining Methodology and Transmission Security
9-28-17	Transmission Security, Results, and Timeline
10-30-17	Transmission Security and Results

NEW YORK INDEPENDENT SYSTEM OPERATOR

Final Market Design

Design Objective

Market Design Statement

Develop a robust, transparent, and intuitive (predictive) process for developing proper capacity requirements that maintain reliability while producing a lower cost solution

Market Guiding Principles

Efficient allocation of capacity

- Maintains reliability
- Cost effective
- Proper investment incentives

Transparent and predictable

- Simple, stable, robust
- Predictable

NEW YORK INDEPENDENT SYSTEM OPERATOR

Methodology

Optimization Methodology

- Determine LCRs for the Localities that minimize total cost of capacity at the level of excess (LOE) condition while maintaining the reliability criterion (LOLE $\leq$ 0.1 days/year), the NYSRC approved IRM, and not exceeding transmission security limits (TSL)
- Cost defined by Unit Net CONE used to develop each ICAP Demand Curve

NEW YORK INDEPENDENT SYSTEM OPERATOR

Minimize:

$$
\begin{aligned}
&\mathit{Total\ Cost\ of\ Capacity} \\
&= \left[\sum_{X} (Q_X + LOE_X) \cdot P_X(Q_X + LOE_X)\right] \\
&+ \left[\sum_{Y} (Q_Y + LOE_Y) \cdot P_Y\left(Q_Y + LOE_Y + \sum_{Z} Q_Z + LOE_Z\right)\right] \\
&+ \left[\left(Q_{NYCA} + LOE_{NYCA} - \left(\sum_{X} (Q_X + LOE_X) + \sum_{Y} (Q_Y + LOE_Y)\right)\right)\right. \\
&\left.\cdot P_{NYCA}(Q_{NYCA} + LOE_{NYCA})\right]
\end{aligned}
$$

NEW YORK INDEPENDENT SYSTEM OPERATOR

P = Price (*i.e.,* Unit Net CONE curves)

Q = Quantity at 100% requirement (MW)

LOE = Quantity associated with Level of Excess (MW)

X = Single Load Zone that is a Locality (*i.e.,* Zone J and Zone K)

Y = Locality minus any Single Load Zone Locality located within it (*i.e.,* GHI)

Z = Single Locality located within a larger Locality (*i.e.,* Zone J)

$NYCA$ = New York Control Area

NEW YORK INDEPENDENT SYSTEM OPERATOR

Subject to:

$$LOLE \leq 0.1 \text{ days/year}$$

$$LCR_J \geq TSL_J$$

$$LCR_K \geq TSL_K$$

$$LCR_{G\text{-}J} \geq TSL_{G\text{-}J}$$

$$IRM = NYSRC \text{ Approved } IRM \text{ (i.e., 18\%)}$$

Computational Method: Linear Approximation

- Iterative process between Linear Program wrapper and MARS that approximates the objective function and constraints to find least cost solution
- Currently uses the Constrained Optimization By Linear Approximation (COBYLA) algorithm available through Python's scientific computing package

MARS Modeling Assumptions

- Utilize the same process as currently used to develop the final LCR base case
  - Update the NYSRC approved final IRM topology to account for the updated load forecast
- Optimize with the appropriate NYSRC final approved IRM

NYSRC

- Presented to the NYSRC ICS throughout 2017 to provide information and discuss the methodology and progression of this project
- The proposed methodology will enable the NYISO to meet its compliance obligations under the NYSRC rules

NEW YORK INDEPENDENT SYSTEM OPERATOR

Cost of Capacity

- Based upon ICAP Demand Curve peaking plant net cost of new entry ("DC unit net CONE") of capacity within each Locality and the NYCA
- Based upon the FERC accepted Demand Curve parameters
- Elasticity is represented by expressing the DC unit net CONE of each Locality and NYCA as a function of the minimum installed capacity requirement

Development of DC unit net CONE Curves

- Evaluate Net EAS at different levels of installed capacity using data from the 2016 Demand Curve Reset process
  - Net EAS for each Locality was evaluated at +6%, +3%, 2016 requirement, -3%, and -6% of the installed capacity requirement
- Results are used to develop a Net EAS curve
- The Net EAS at each point on the curve is used to calculate a corresponding Net CONE
- Net CONE values are used to develop a DC unit net CONE curve for each Locality and NYCA

NEW YORK INDEPENDENT SYSTEM OPERATOR

Transmission Security Methodology

- N-1-1 analysis is conducted to determine the transmission security import limits into each Locality
- These import limits are used to determine the minimum available capacity required for each Locality
- To translate this minimum available capacity into a market requirement the methodology needs to account for capacity unavailability
- To account for capacity unavailability, the 5-year zonal EFORd is used to calculate minimum locational capacity requirements

NEW YORK INDEPENDENT SYSTEM OPERATOR

N-1-1 Transmission Security Limit (TSL) Analysis

- **Analyzes the N-1-1 thermal transfer limits for the NYCA interfaces associated with the G-J, Zone J, and Zone K Localities**
- **Use an updated Summer Operating base case**
  - Inclusion of transmission and generation facility additions and retirements
  - All system elements modeled as in service
  - Appropriate load forecast
- **Report with N-1-1 import limits will be posted prior to October 1st of each year**
- **Final TSLs for the optimization will be established and posted in January each year**

Example Calculation

Transmission Security Requirements	Formula	Zone X
Load Forecast (MW)	[A] = Given	12,000
Transmission Security Import Limit (MW)	[B] = Given	1,500
Transmission Security UCAP Requirement (MW)	[C] = [A]-[B]	10,500
Transmission Security UCAP Requirement (%)	[D] = [C]/[A]	87.5%
5 Year EFORd (%)	[E] = Given	8.0%
Transmission Security ICAP Requirement (MW)	[F] = [C]/(1-[E])	11,413
Transmission Security LCR Floor (%)	[G] = [F]/[A]	**95.1%**

NEW YORK INDEPENDENT SYSTEM OPERATOR

Results

Base Case

Scenario	Zone J LCR	Zone K LCR	G-J LCR	Cost ($ million)
Current LCR Methodology	81.4%	103.2%	91.3%	$4,441.90
Optimized Methodology without Transmission Security Limits (TSL)	78.0%	105.3%	91.5%	$4,402.89
Optimized Methodology with Transmission Security Limits (TSL)[1]	**80.16%**	**104.15%**	**90.71%**	**$4,424.37**

[1]Uses TSL – preliminary results

DRAFT – FOR DISCUSSION PURPOSES ONLY

Base Case

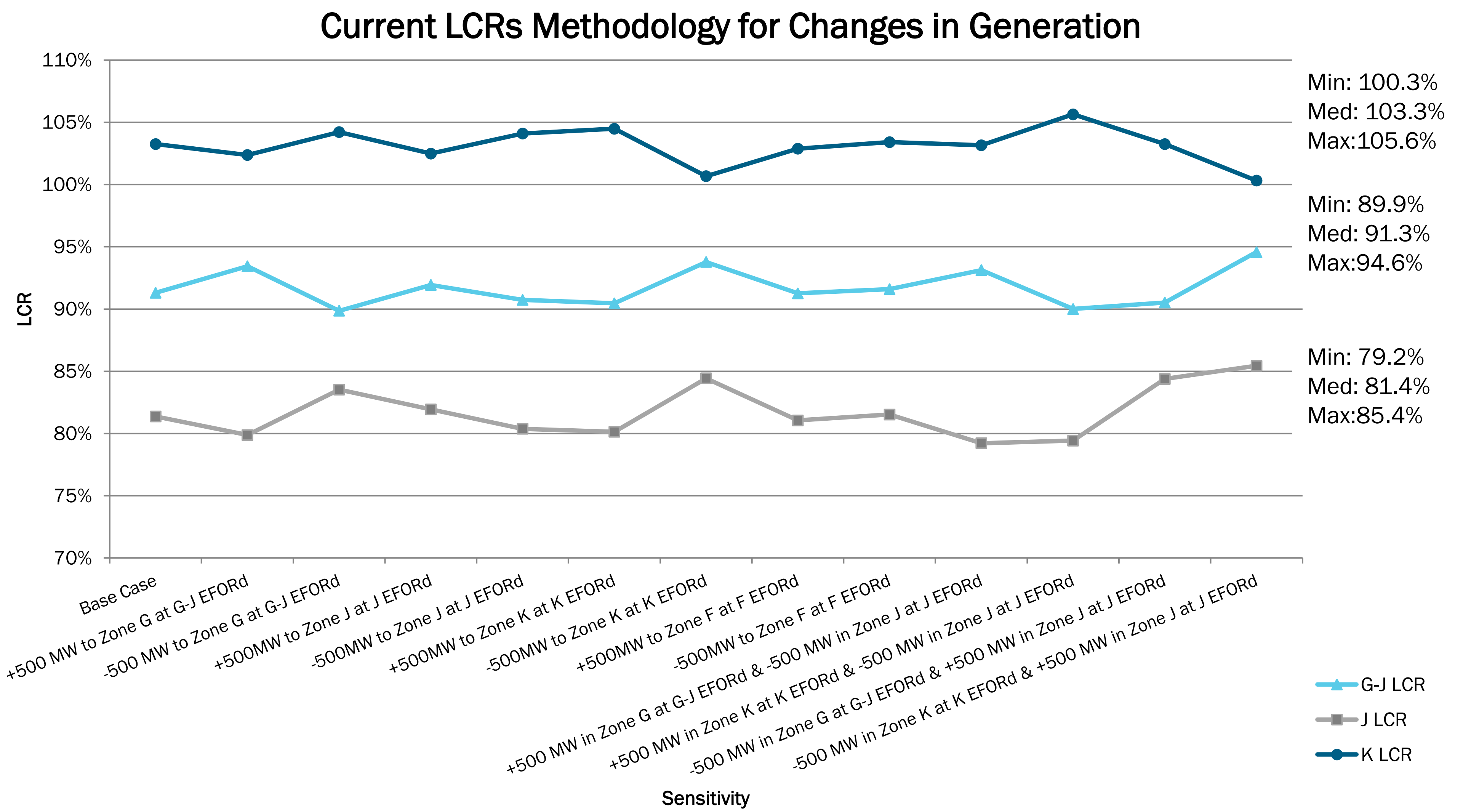
Scenario	Zone J LCR	Zone K LCR	G-J LCR
Current LCR Methodology	9,495 MW	5,603 MW	14,664 MW
Optimized Methodology without Transmission Security Limits (TSL)	9,102 MW	5,715 MW	14,696 MW
Optimized Methodology with Transmission Security Limits (TSL)[2]	**9,355 MW**	**5,652 MW**	**14,570 MW**

[2]Uses TSL – preliminary results

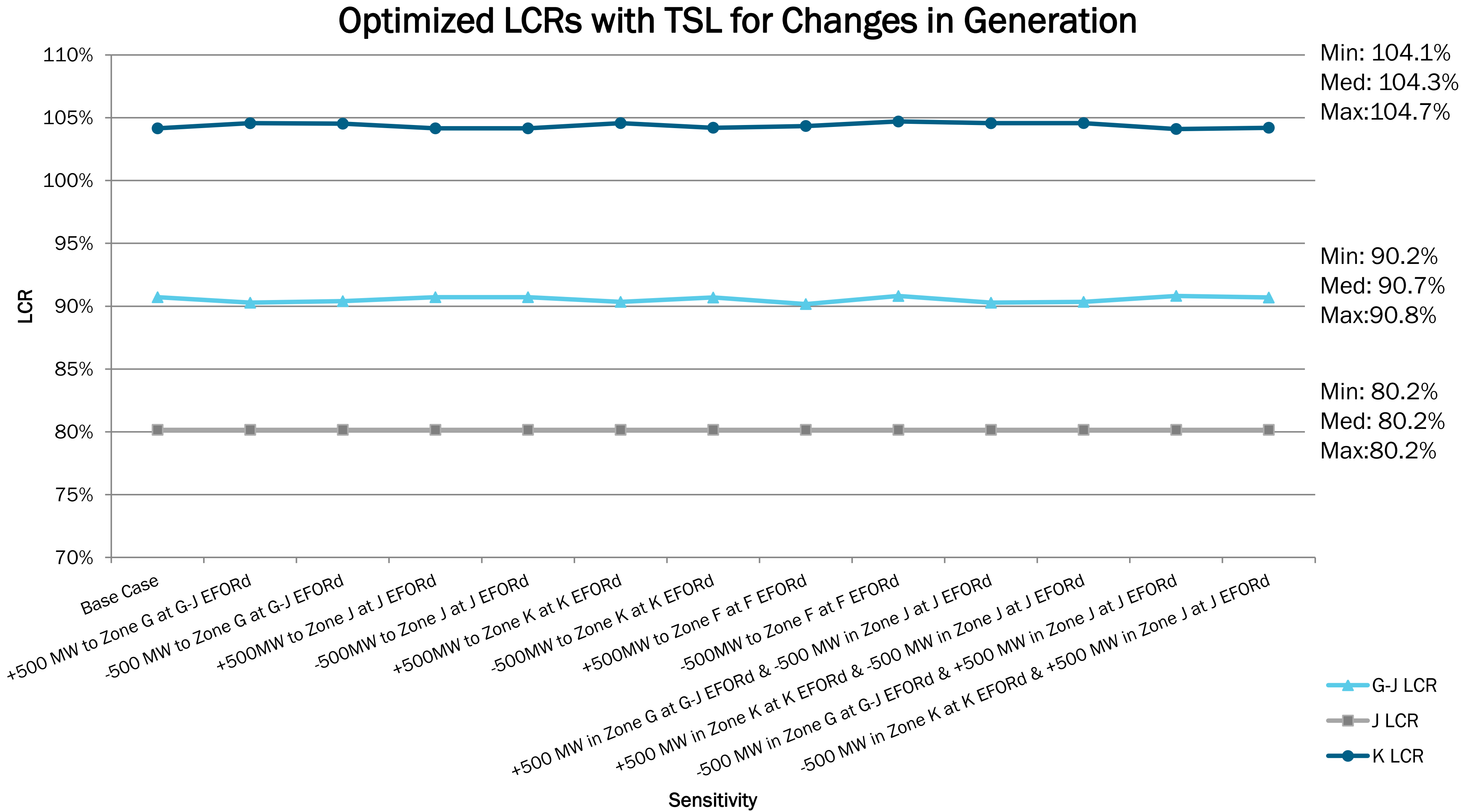
NEW YORK INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY

Market Stability with Changes in Generation



Current LCRs Methodology for Changes in Generation
110%
105%
100%
95%
90%
85%
80%
75%
70%
LCR
Min: 100.3%
Med: 103.3%
Max:105.6%
Min: 89.9%
Med: 91.3%
Max:94.6%
Min: 79.2%
Med: 81.4%
Max:85.4%
Base Case
+500 MW to Zone G at G-J EFORd
-500 MW to Zone G at G-J EFORd
+500MW to Zone J at J EFORd
-500MW to Zone J at J EFORd
+500MW to Zone K at K EFORd
-500MW to Zone K at K EFORd
+500MW to Zone F at F EFORd
-500MW to Zone F at F EFORd
+500 MW in Zone G at G-J EFORd & -500 MW in Zone J at J EFORd
+500 MW in Zone K at K EFORd & -500 MW in Zone J at J EFORd
-500 MW in Zone G at G-J EFORd & +500 MW in Zone J at J EFORd
-500 MW in Zone K at K EFORd & +500 MW in Zone J at J EFORd
Sensitivity
G-J LCR
J LCR
K LCR


Optimized LCRs with TSL for Changes in Generation
110%
105%
100%
95%
90%
85%
80%
75%
70%
LCR
Min: 104.1%
Med: 104.3%
Max:104.7%
Min: 90.2%
Med: 90.7%
Max:90.8%
Min: 80.2%
Med: 80.2%
Max:80.2%
Base Case
+500 MW to Zone G at G-J EFORd
-500 MW to Zone G at G-J EFORd
+500MW to Zone J at J EFORd
-500MW to Zone J at J EFORd
+500MW to Zone K at K EFORd
-500MW to Zone K at K EFORd
+500MW to Zone F at F EFORd
-500MW to Zone F at F EFORd
+500 MW in Zone G at G-J EFORd & -500 MW in Zone J at J EFORd
+500 MW in Zone K at K EFORd & -500 MW in Zone J at J EFORd
-500 MW in Zone G at G-J EFORd & +500 MW in Zone J at J EFORd
-500 MW in Zone K at K EFORd & +500 MW in Zone J at J EFORd
Sensitivity
G-J LCR
J LCR
K LCR

Stability of LCRs

- The optimization methodology results in an increase in stability as generation changes occur within the system

Methodology	Range of LCRs in Change in Generation Sensitivities		
	Zone K	Zone J	G-J
Current LCR Methodology	5.3%	6.2%	4.7%
Optimized with TSL[3]	0.6%	0.0%	0.7%

[3]Sensitivities based on TSL – preliminary results

NEW YORK INDEPENDENT SYSTEM OPERATOR

Stability of LCRs

Methodology	Range of LCRs		
	Zone K	Zone J	G-J
Current LCR Methodology	289 MW	725 MW	756 MW
Optimized with TSL[4]	32 MW	0 MW	104 MW

[4]Sensitivities based upon TSL – preliminary results

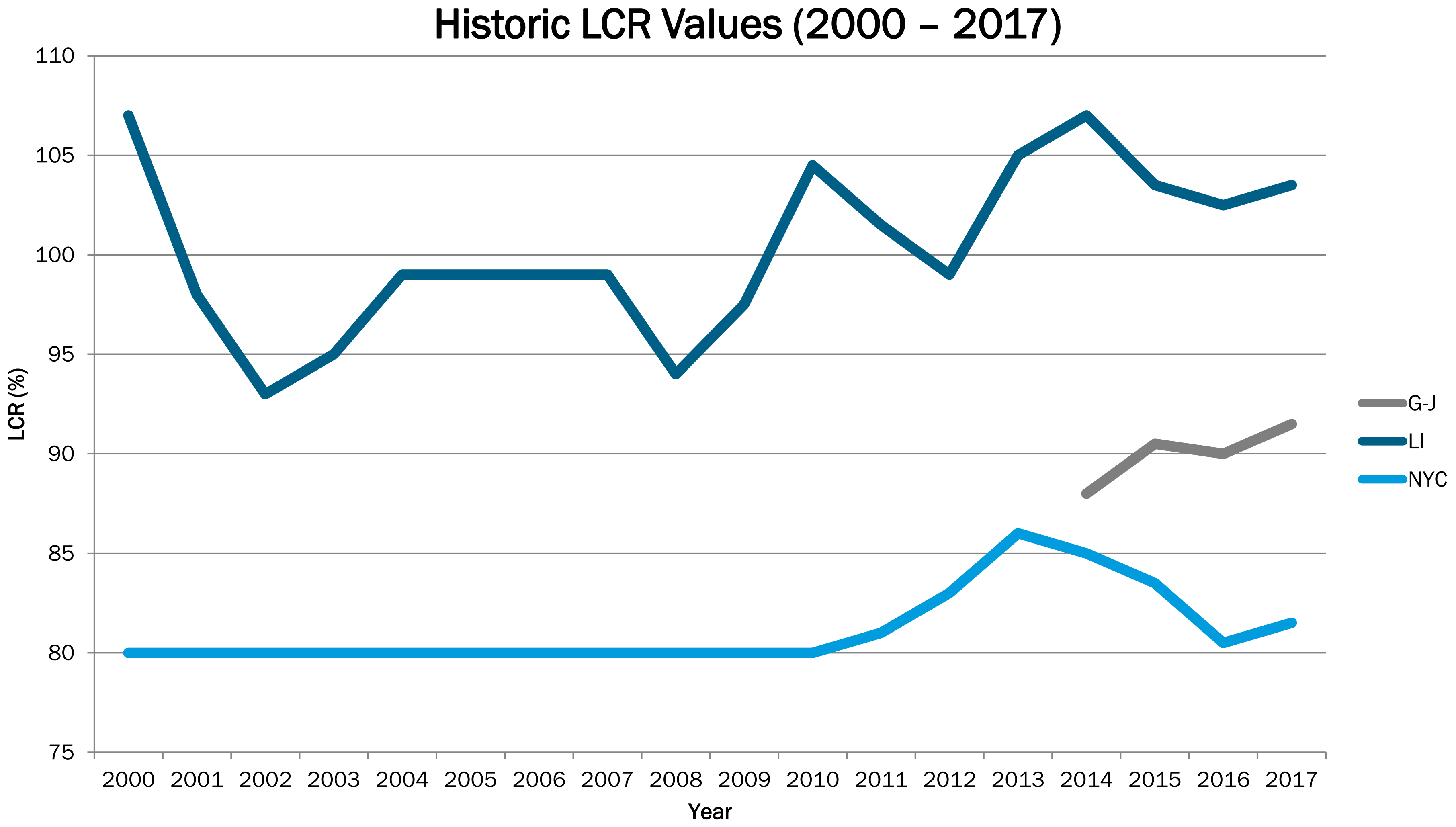
Review of Potential Inclusion of Cost Allocation Provision

Historic LCR Values for last 5 years (2013-2017)

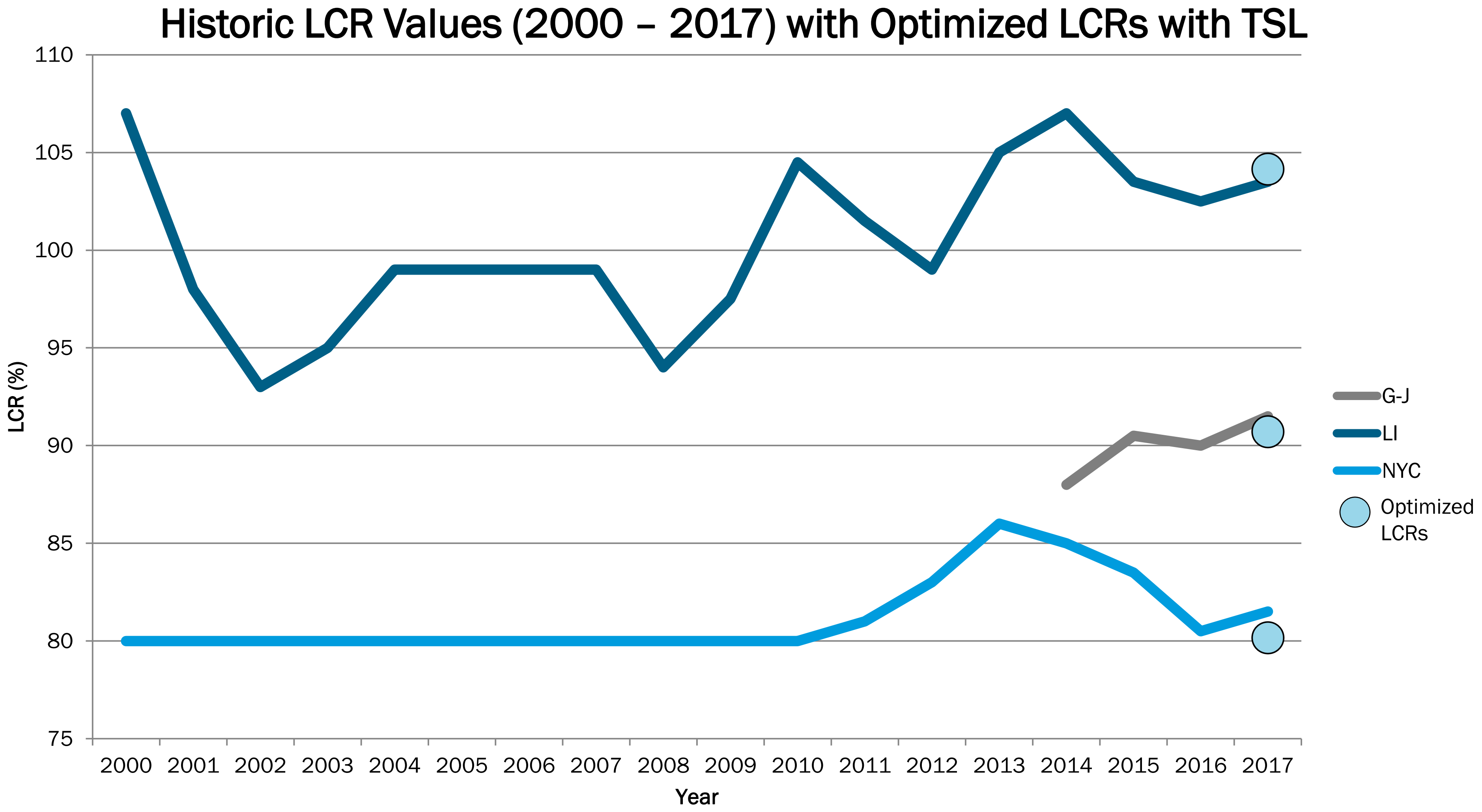
	Zone J	Zone K	G-J[5]
Minimum	80.5%	102.5%	88.0%
Average	83.3%	103.4%	90.0%
Maximum	86.0%	107.0%	91.5%
Optimized Methodology with Transmission Security Limits (TSL)[6]	80.16%	104.15%	90.71%

[5] LCRs were established for G-J starting in 2014

[6]Based upon TSL – preliminary results



Historic LCR Values (2000 – 2017)
110
105
100
95
90
85
80
75
LCR (%)
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
Year
G-J
LI
NYC

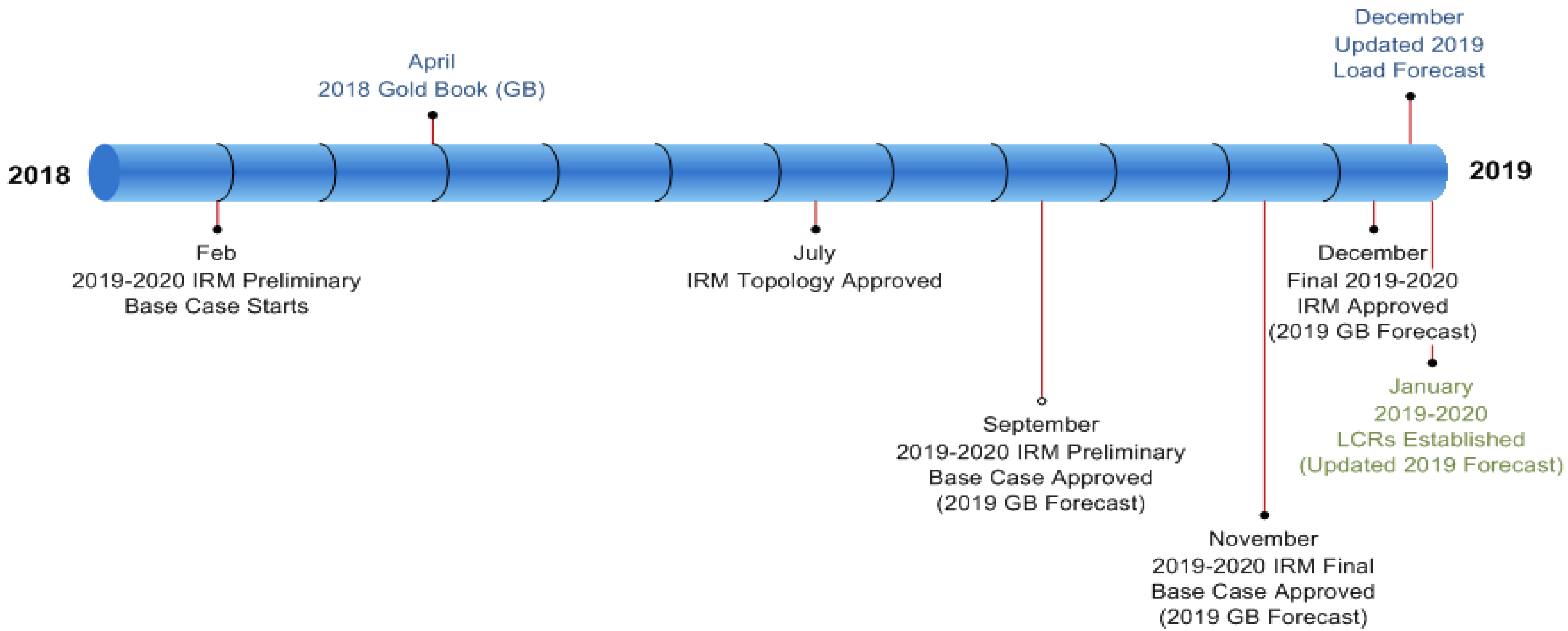

Historic LCR Values (2000 – 2017) with Optimized LCRs with TSL
110
105
100
95
90
85
80
75
LCR (%)
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
Year
G-J
LI
NYC
Optimized LCRs

Cost Allocation

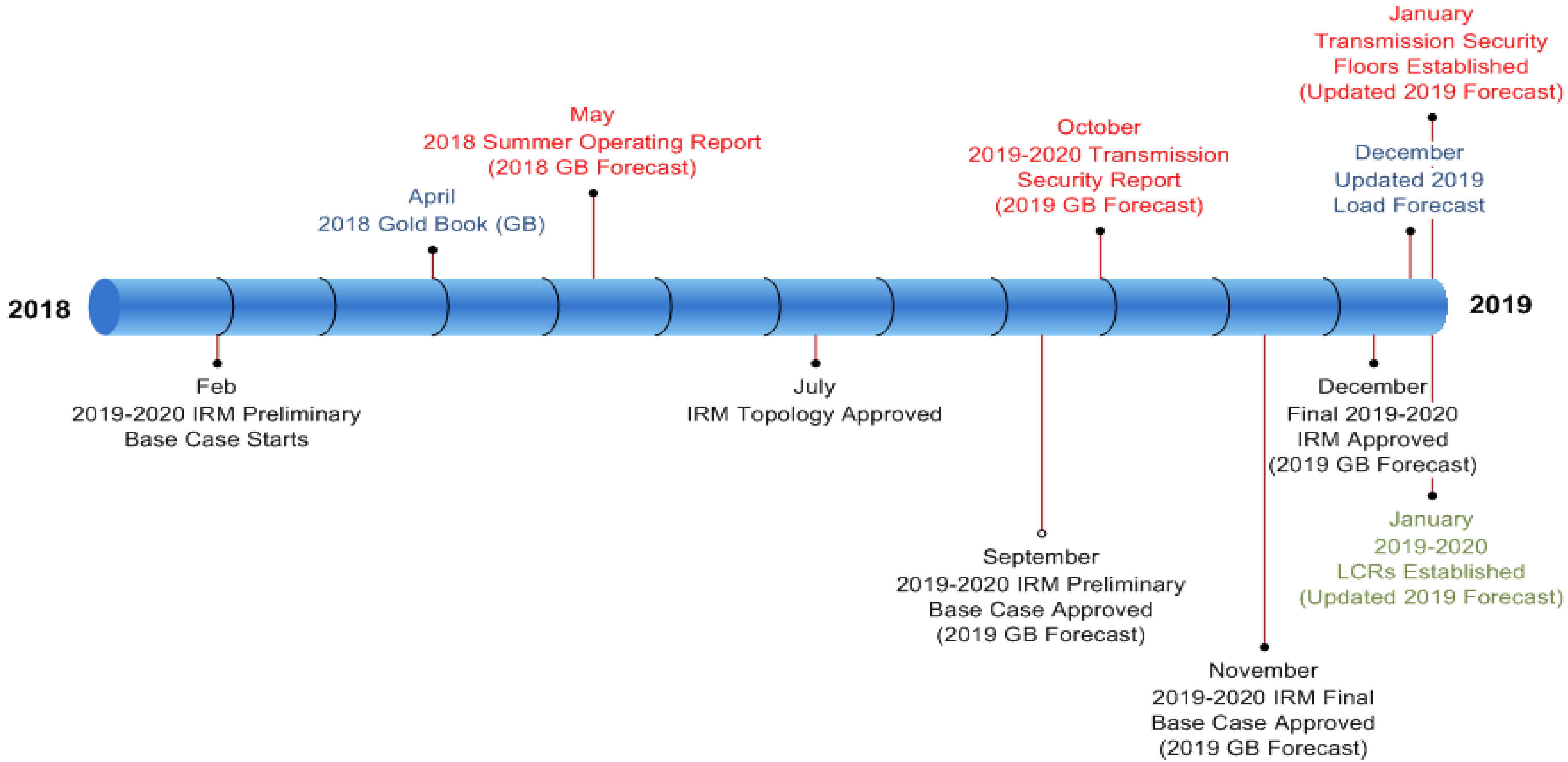
- Since the optimization methodology results in LCRs within the historic range, an evaluation of a potential revision to the cost allocation that results appears to be unnecessary
  - In addition, the optimization is providing increased market stability with respect to changes in generation
- If conditions should occur that warrant reviewing and revising cost allocation methodology, the NYISO and stakeholders could take it into consideration. In addition, stakeholders may prioritize it in a future BPWG process as a future project

Timeline

Current Timeline



Timeline Additions



LCR Setting Timeline

- No alterations to the current timeline are needed to accommodate the alternative methodology for determining LCRs
- Transmission security analysis used in the alternative methodology would be conducted and reported prior to October 1st
  - This analysis would utilize an updated base case used in the Summer Operating Report

Next Steps

2018 Project Scope

- Review existing Tariff language and draft Tariff language to reflect new methodology as necessary
  - Work with stakeholders in ICAP Working Group, and then present to BIC and MC for action, and Board approval
- File revised Tariff language with FERC
- Revise LCR methodology documentation and any manual revisions required
- Develop internal process for implementation
- Address any administrative issues (ongoing)

Questions?

The Mission of the New York Independent System Operator, in collaboration with its stakeholders, is to serve the public interest and provide benefits to consumers by:

- Maintaining and enhancing regional reliability
- Operating open, fair and competitive wholesale electricity markets
- Planning the power system for the future
- Providing factual information to policy makers, stakeholders and investors in the power system

www.nyiso.com

NEW YORK INDEPENDENT SYSTEM OPERATOR

Appendix

CONFORMANCE WITH NYSRC REQUIREMENTS

The NYISO confirms that the new proposed methodology for calculating minimum locational installed capacity requirements (“LCRs”) is designed to satisfy the following criteria:

- A LOLE of 0.1 days/year, as specified by NYSRC Reliability Rule A.2: R1, shall be maintained.
- The NYISO shall use the software, load and capacity data, and models consistent with that utilized by the NYSRC for its preparation of the IRM, as described in Sections 3.2 and 3.5 of NYSRC Policy 5-12.
- The NYISO shall use the final Installed Reserve Margin established by the NYSRC.
- The NYISO shall document the procedures used to calculate LCRs.

NEW YORK INDEPENDENT SYSTEM OPERATOR

Market Simulations

Single Change in Generation

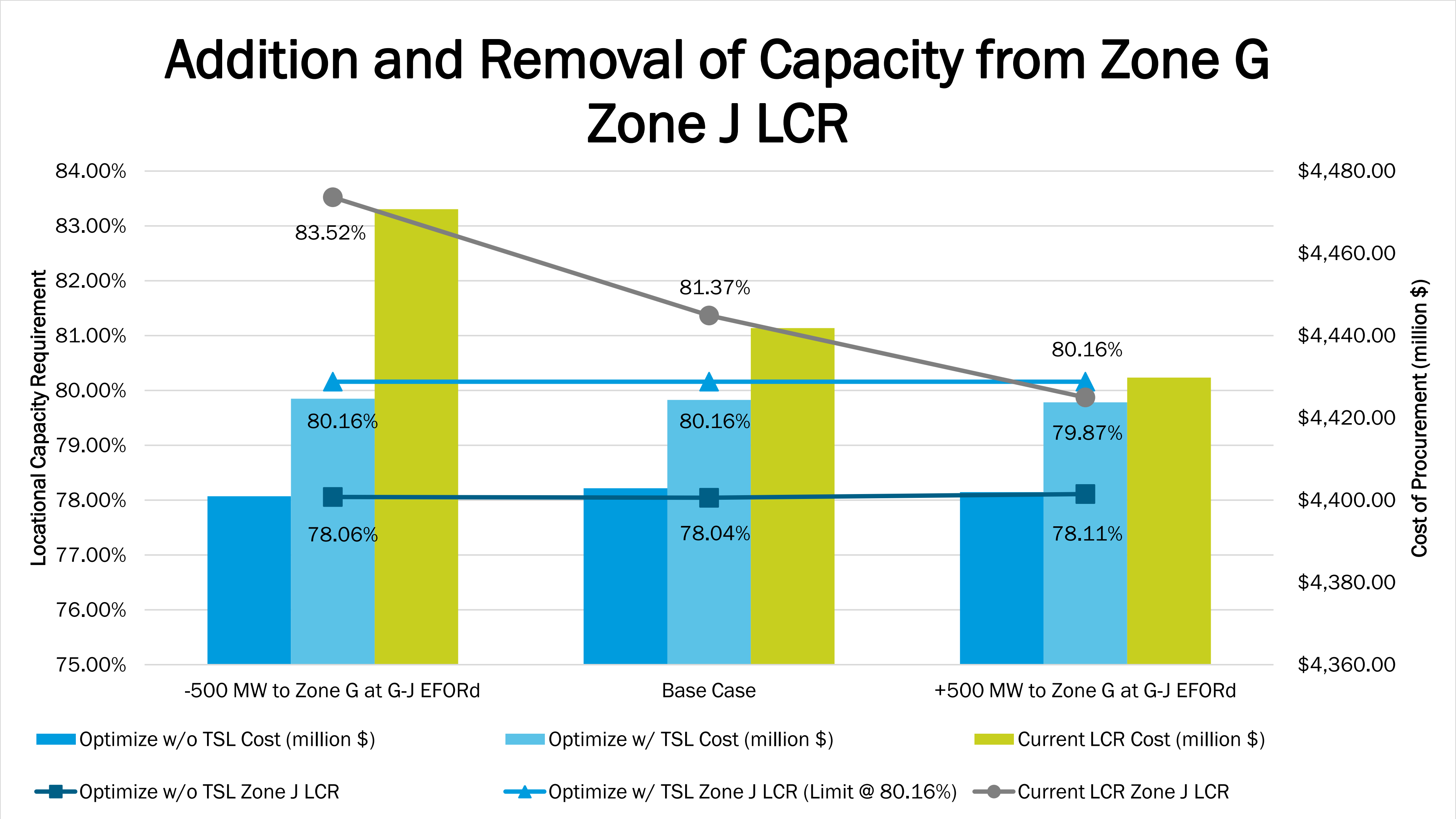
- +/- 500 MW to Zone G at G-J EFORd
- +/- 500 MW to Zone J at J EFORd
- +/- 500 MW to Zone K at K EFORd
- +/- 500 MW to Zone F at F EFORd

NEW YORK INDEPENDENT SYSTEM OPERATOR

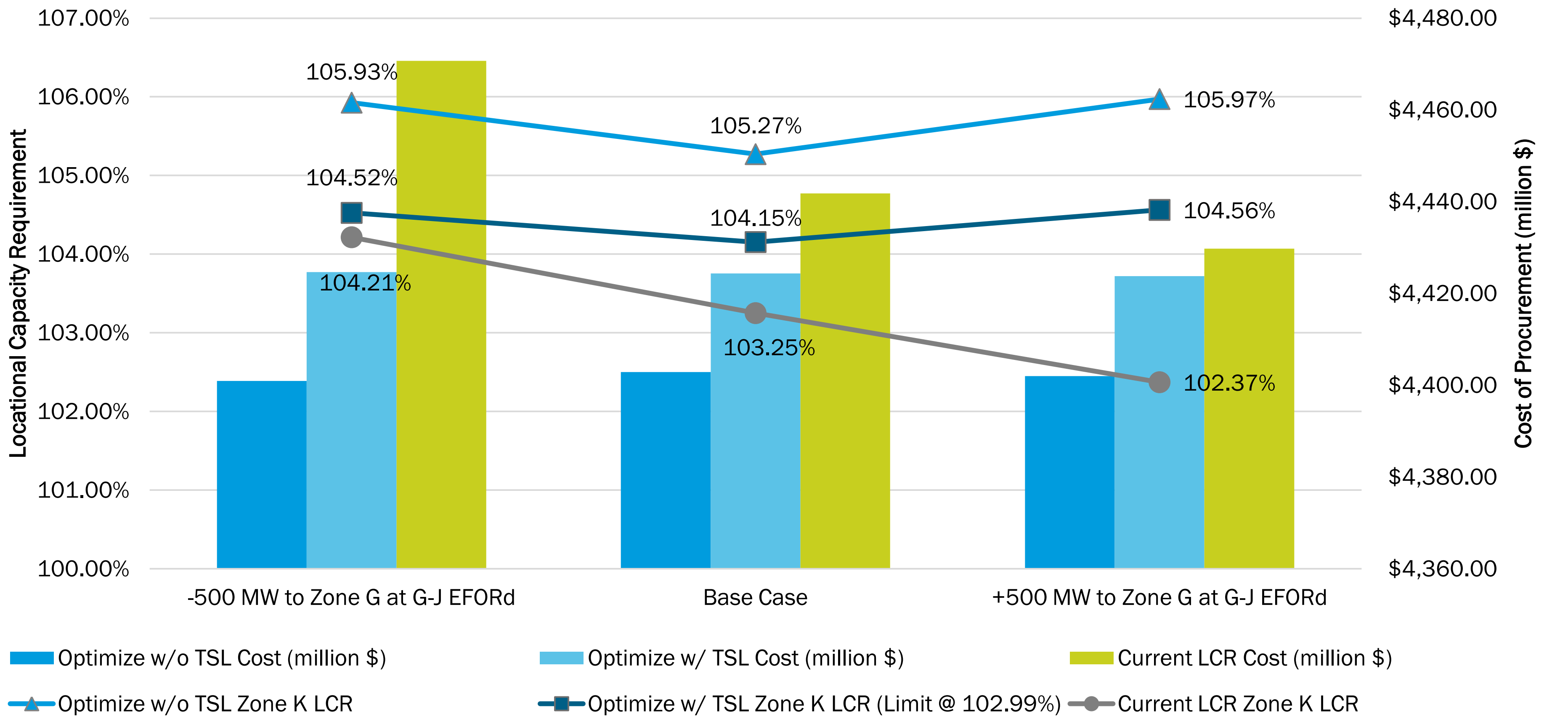
Market Simulations: +/- 500 MW to Zone G

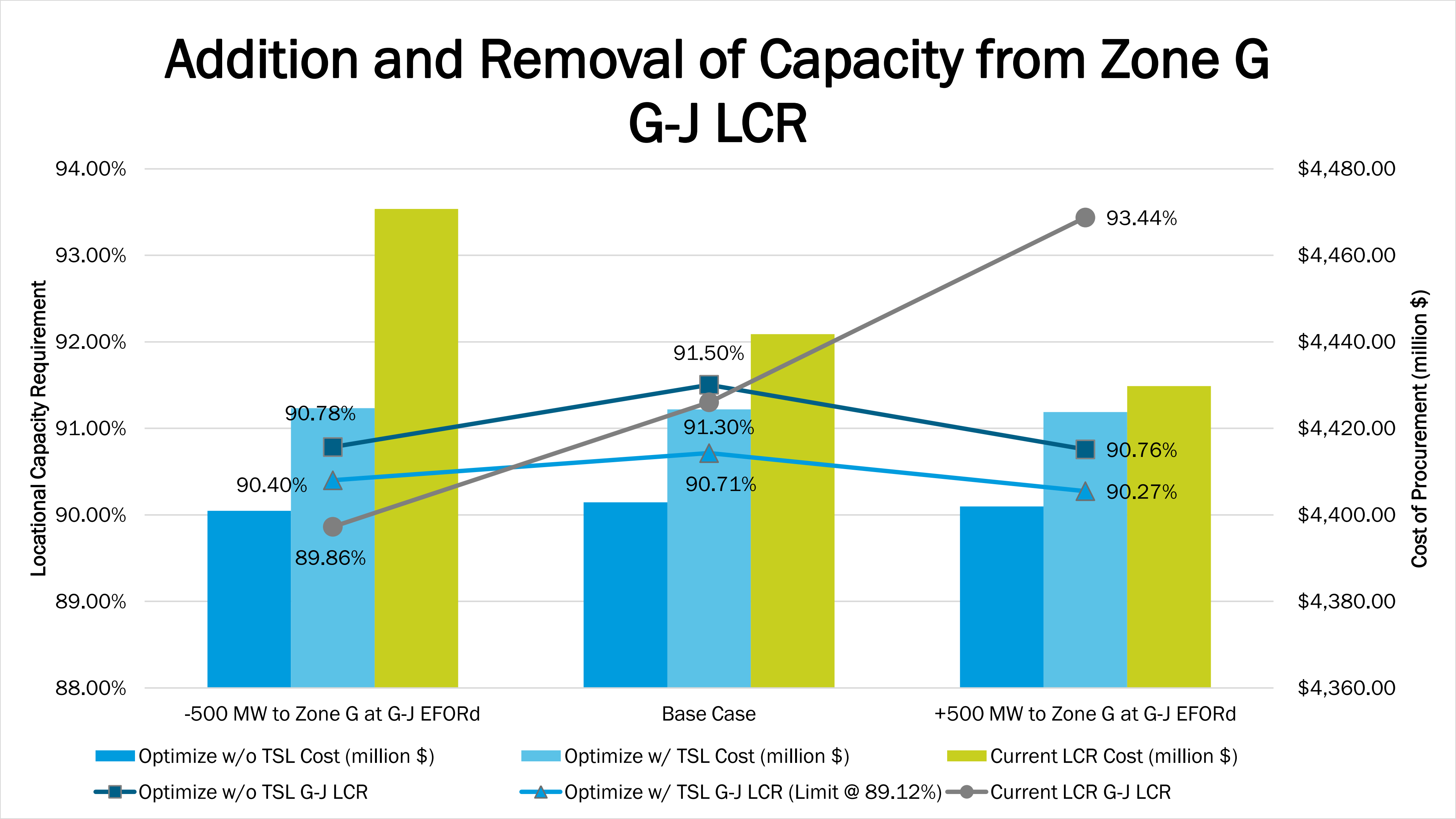
NEW YORK INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY


Addition and Removal of Capacity from Zone G
Zone J LCR
84.00%
83.00%
82.00%
81.00%
80.00%
79.00%
78.00%
77.00%
76.00%
75.00%
Locational Capacity Requirement
$4,480.00
$4,460.00
$4,440.00
$4,420.00
$4,400.00
$4,380.00
$4,360.00
Cost of Procurement (million $)
83.52%
81.37%
80.16%
80.16%
80.16%
79.87%
78.06%
78.04%
78.11%
-500 MW to Zone G at G-J EFORd
Base Case
+500 MW to Zone G at G-J EFORd
Optimize w/o TSL Cost (million $)
Optimize w/ TSL Cost (million $)
Current LCR Cost (million $)
Optimize w/o TSL Zone J LCR
Optimize w/ TSL Zone J LCR (Limit @ 80.16%)
Current LCR Zone J LCR

Addition and Removal of Capacity from Zone G Zone K LCR

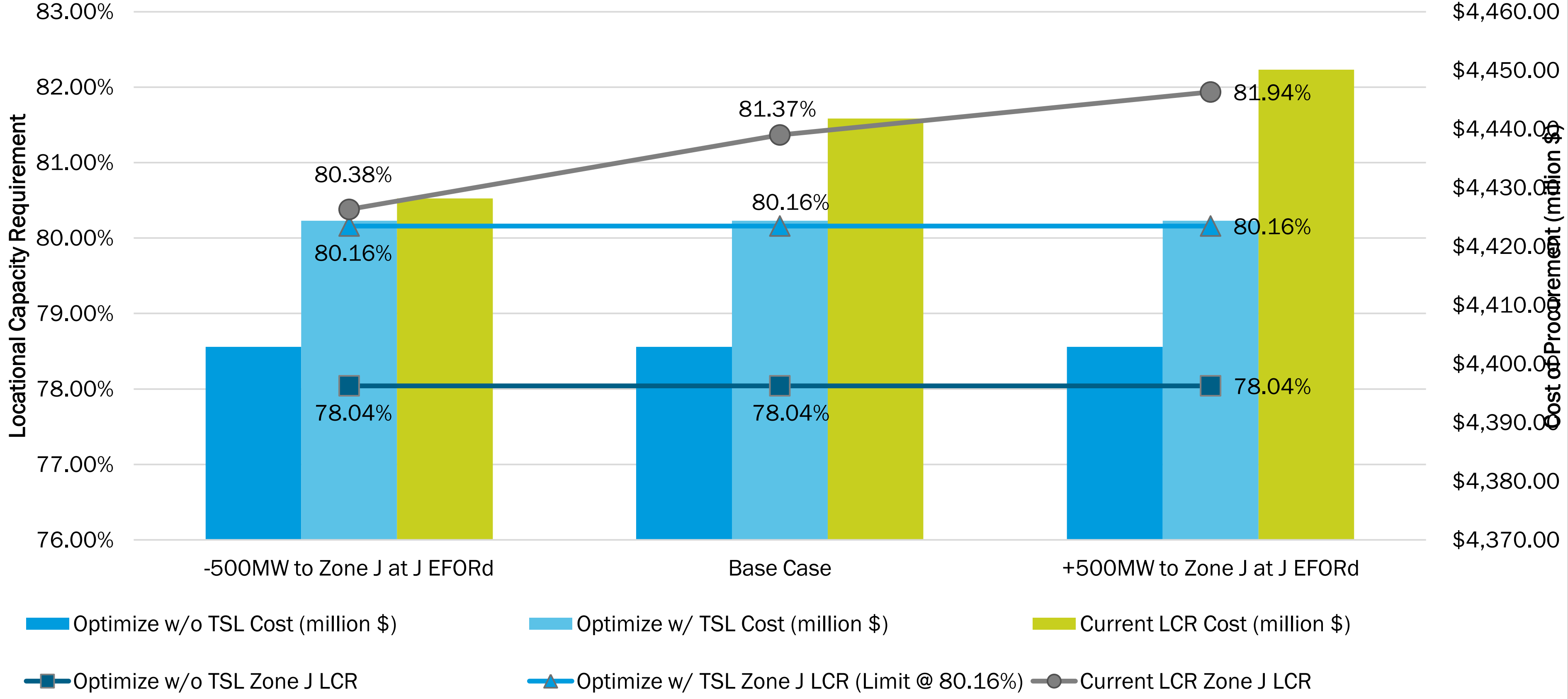




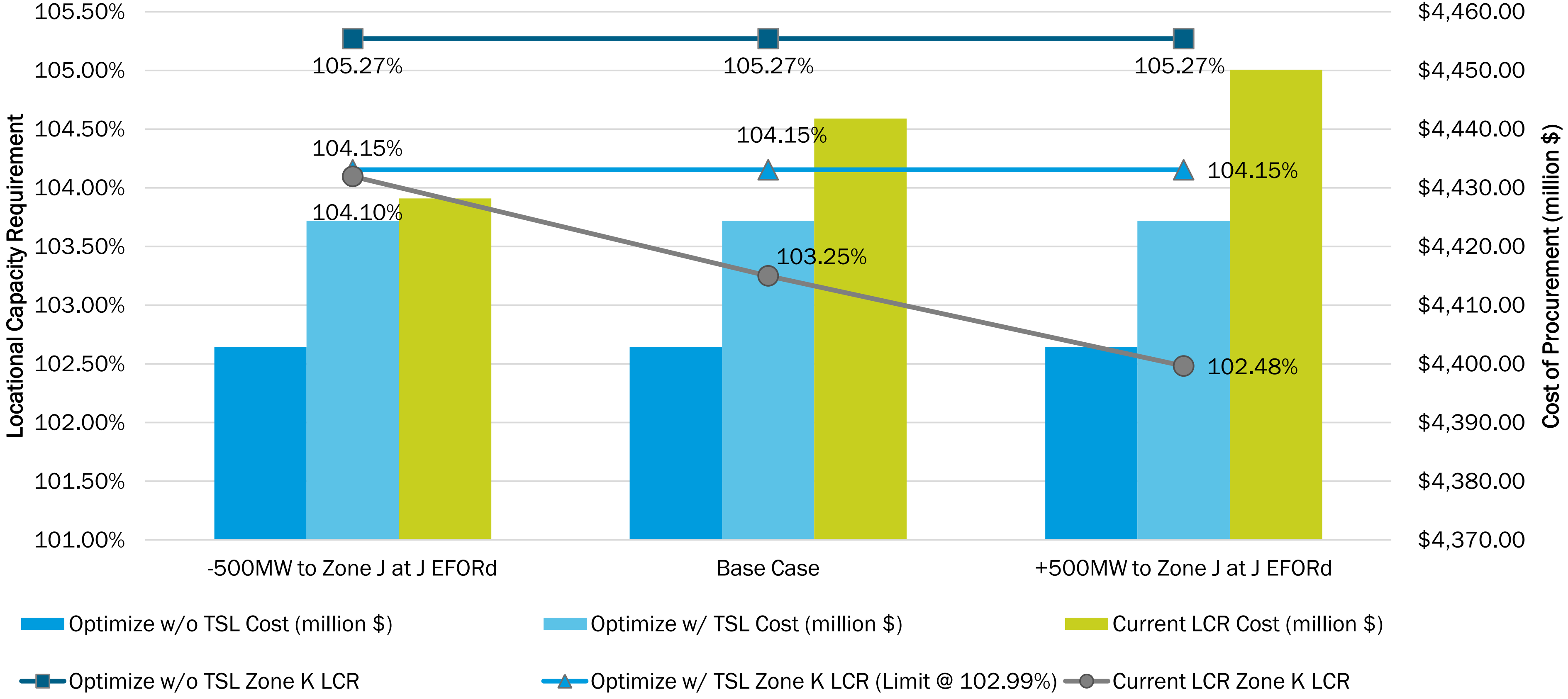
Addition and Removal of Capacity from Zone G
G-J LCR
Locational Capacity Requirement
Cost of Procurement (million $)
94.00%
93.00%
92.00%
91.00%
90.00%
89.00%
88.00%
$4,480.00
$4,460.00
$4,440.00
$4,420.00
$4,400.00
$4,380.00
$4,360.00
93.44%
91.50%
90.78%
91.30%
90.76%
90.40%
90.71%
90.27%
89.86%
-500 MW to Zone G at G-J EFORd
Base Case
+500 MW to Zone G at G-J EFORd
Optimize w/o TSL Cost (million $)
Optimize w/ TSL Cost (million $)
Current LCR Cost (million $)
Optimize w/o TSL G-J LCR
Optimize w/ TSL G-J LCR (Limit @ 89.12%)
Current LCR G-J LCR

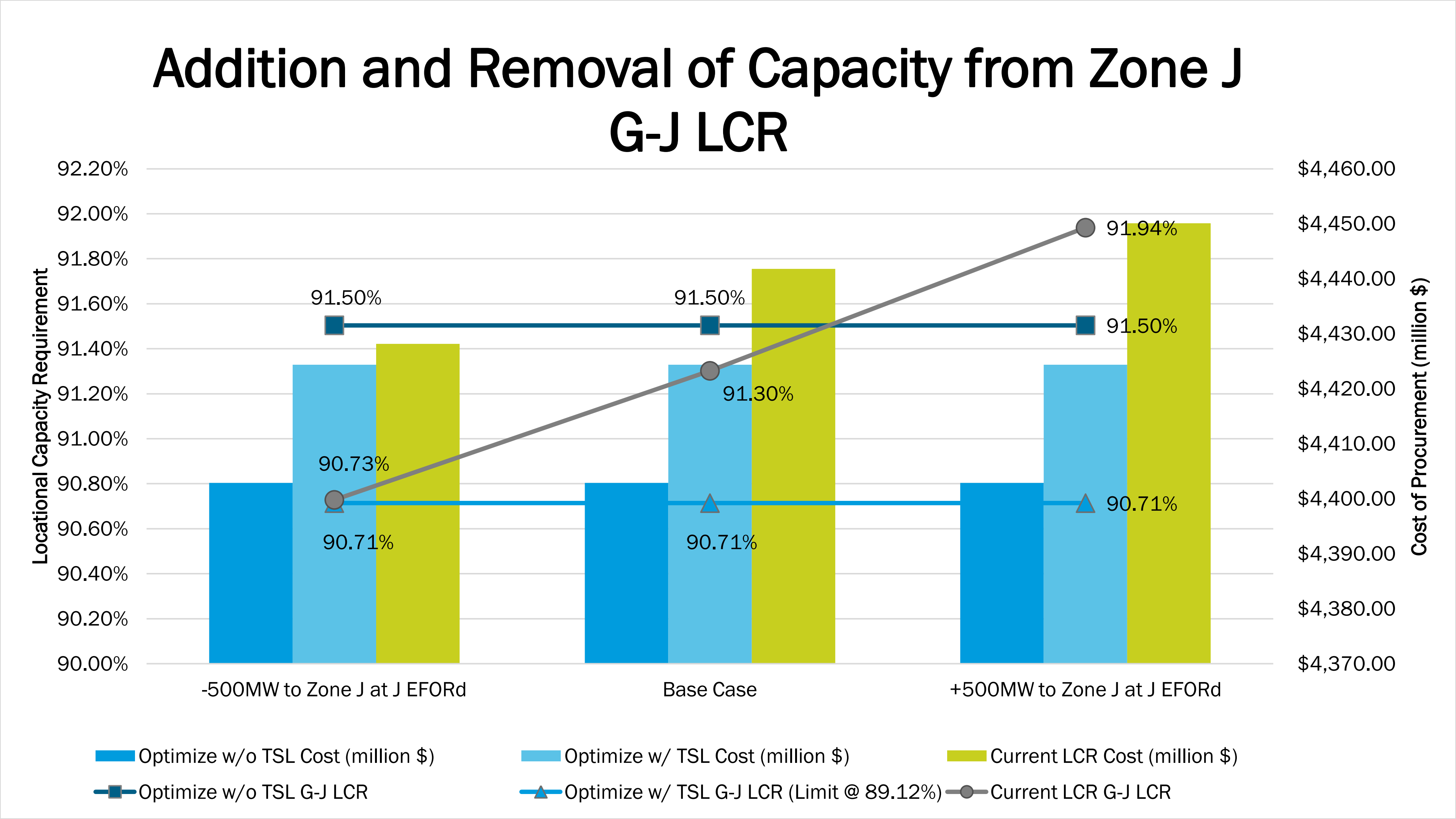
Market Simulations: +/- 500 MW to Zone J

Addition and Removal of Capacity from Zone J
Zone J LCR



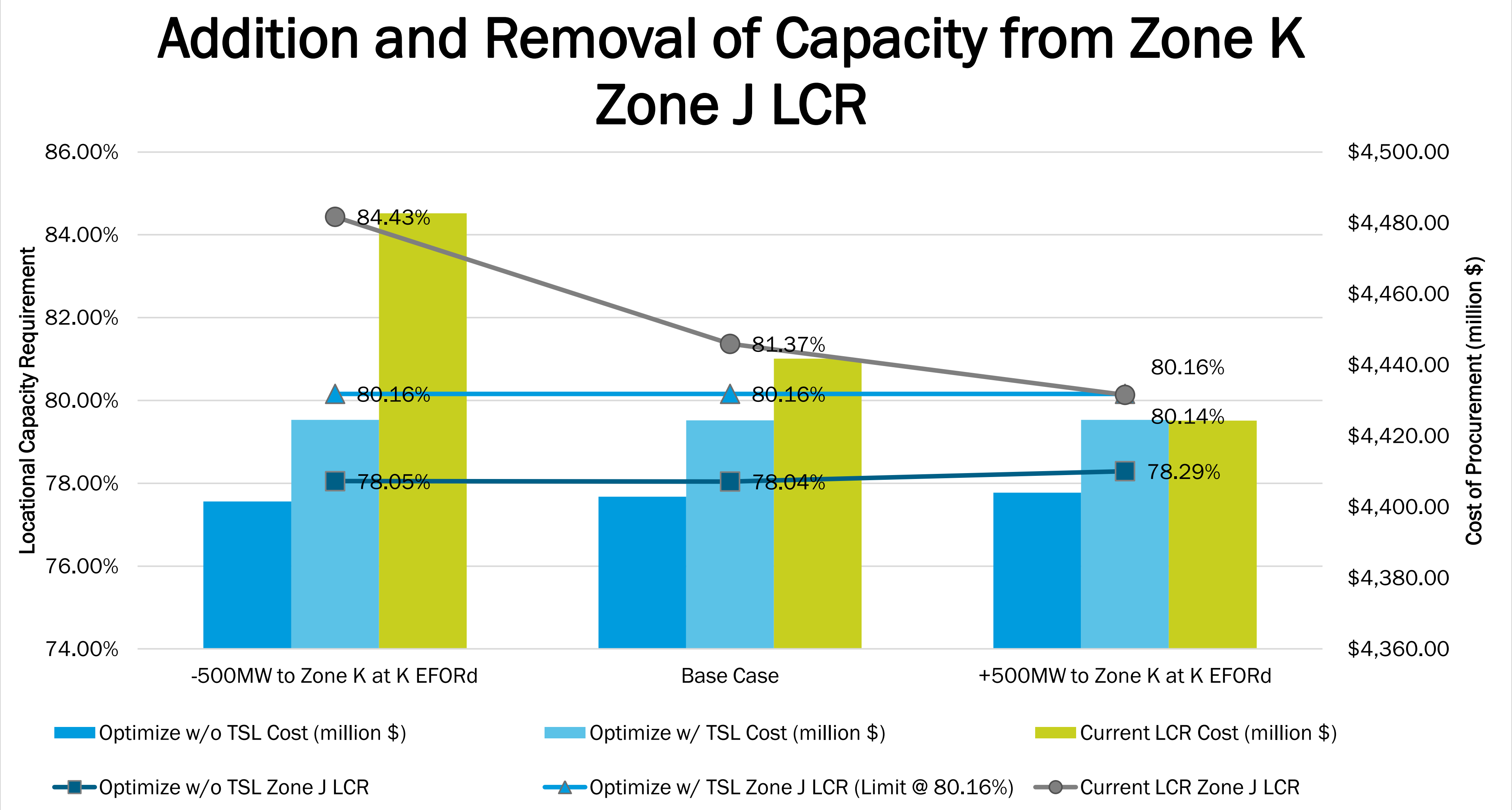
Addition and Removal of Capacity from Zone J Zone K LCR



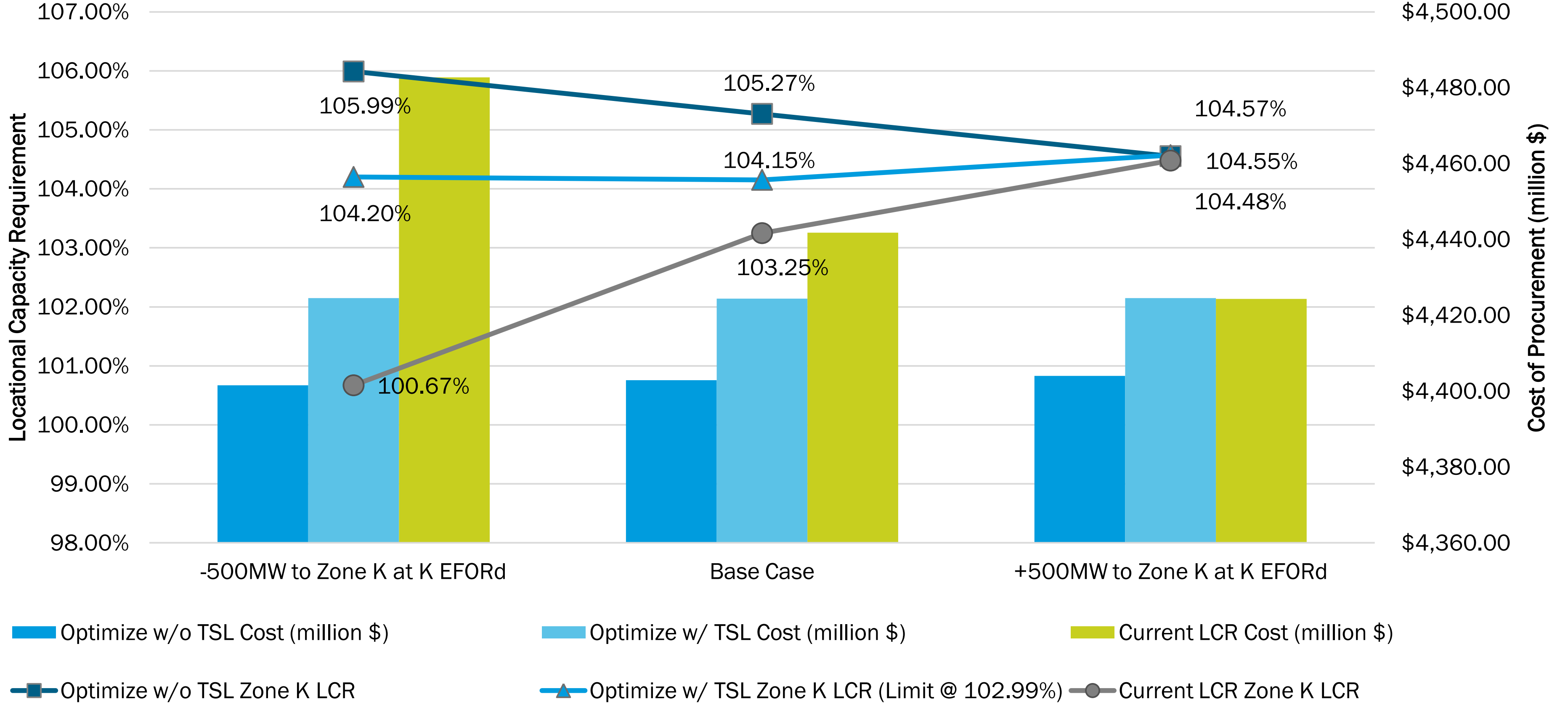


Addition and Removal of Capacity from Zone J
G-J LCR
92.20%
92.00%
91.80%
91.60%
91.40%
91.20%
91.00%
90.80%
90.60%
90.40%
90.20%
90.00%
Locational Capacity Requirement
$4,460.00
$4,450.00
$4,440.00
$4,430.00
$4,420.00
$4,410.00
$4,400.00
$4,390.00
$4,380.00
$4,370.00
Cost of Procurement (million $)
91.50%
91.50%
91.50%
91.94%
91.30%
90.73%
90.71%
90.71%
90.71%
-500MW to Zone J at J EFORd
Base Case
+500MW to Zone J at J EFORd
Optimize w/o TSL Cost (million $)
Optimize w/ TSL Cost (million $)
Current LCR Cost (million $)
Optimize w/o TSL G-J LCR
Optimize w/ TSL G-J LCR (Limit @ 89.12%)
Current LCR G-J LCR

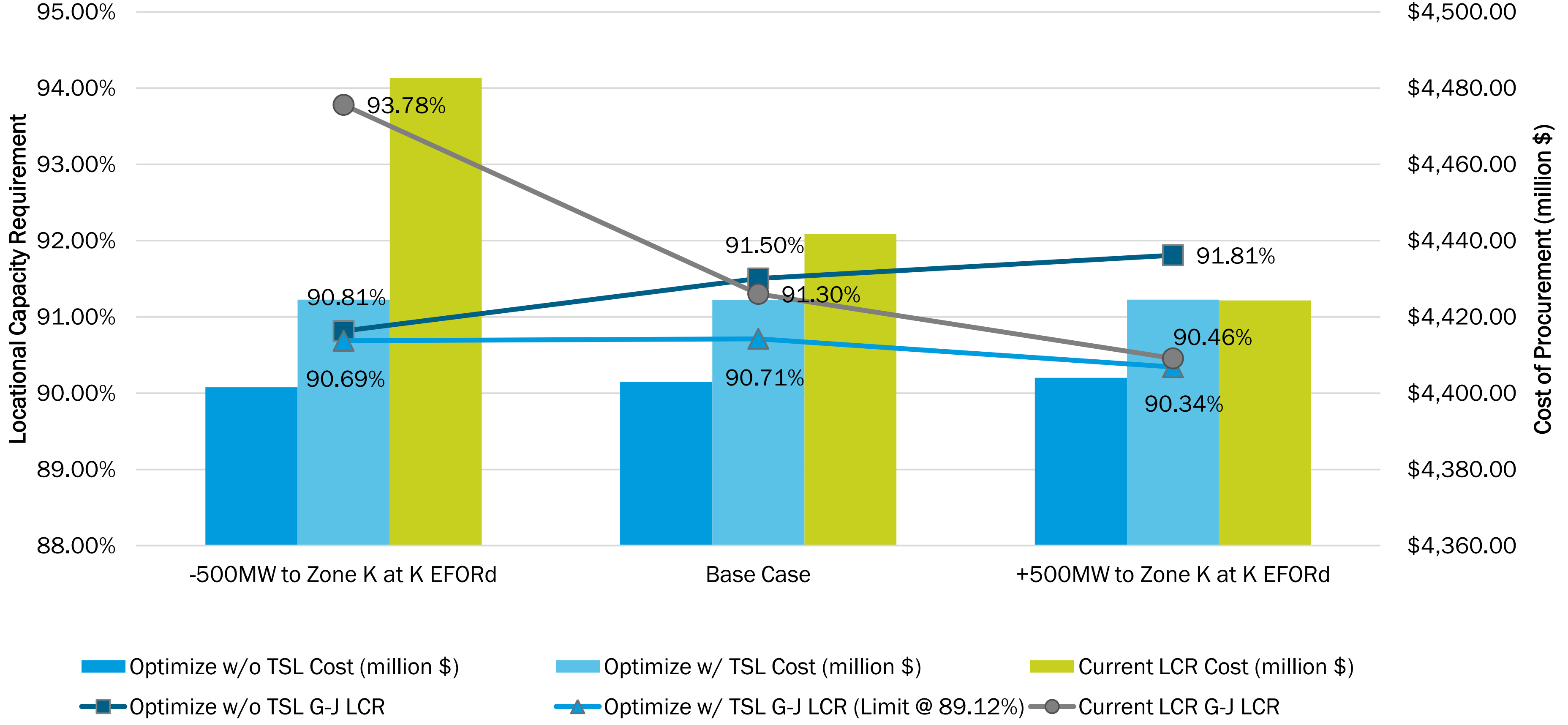
Market Simulations: +/- 500 MW to Zone K


Addition and Removal of Capacity from Zone K
Zone J LCR
Locational Capacity Requirement
Cost of Procurement (million $)
86.00%
84.00%
82.00%
80.00%
78.00%
76.00%
74.00%
$4,500.00
$4,480.00
$4,460.00
$4,440.00
$4,420.00
$4,400.00
$4,380.00
$4,360.00
84.43%
81.37%
80.16%
80.16%
80.16%
80.14%
78.05%
78.04%
78.29%
-500MW to Zone K at K EFORd
Base Case
+500MW to Zone K at K EFORd
Optimize w/o TSL Cost (million $)
Optimize w/ TSL Cost (million $)
Current LCR Cost (million $)
Optimize w/o TSL Zone J LCR
Optimize w/ TSL Zone J LCR (Limit @ 80.16%)
Current LCR Zone J LCR

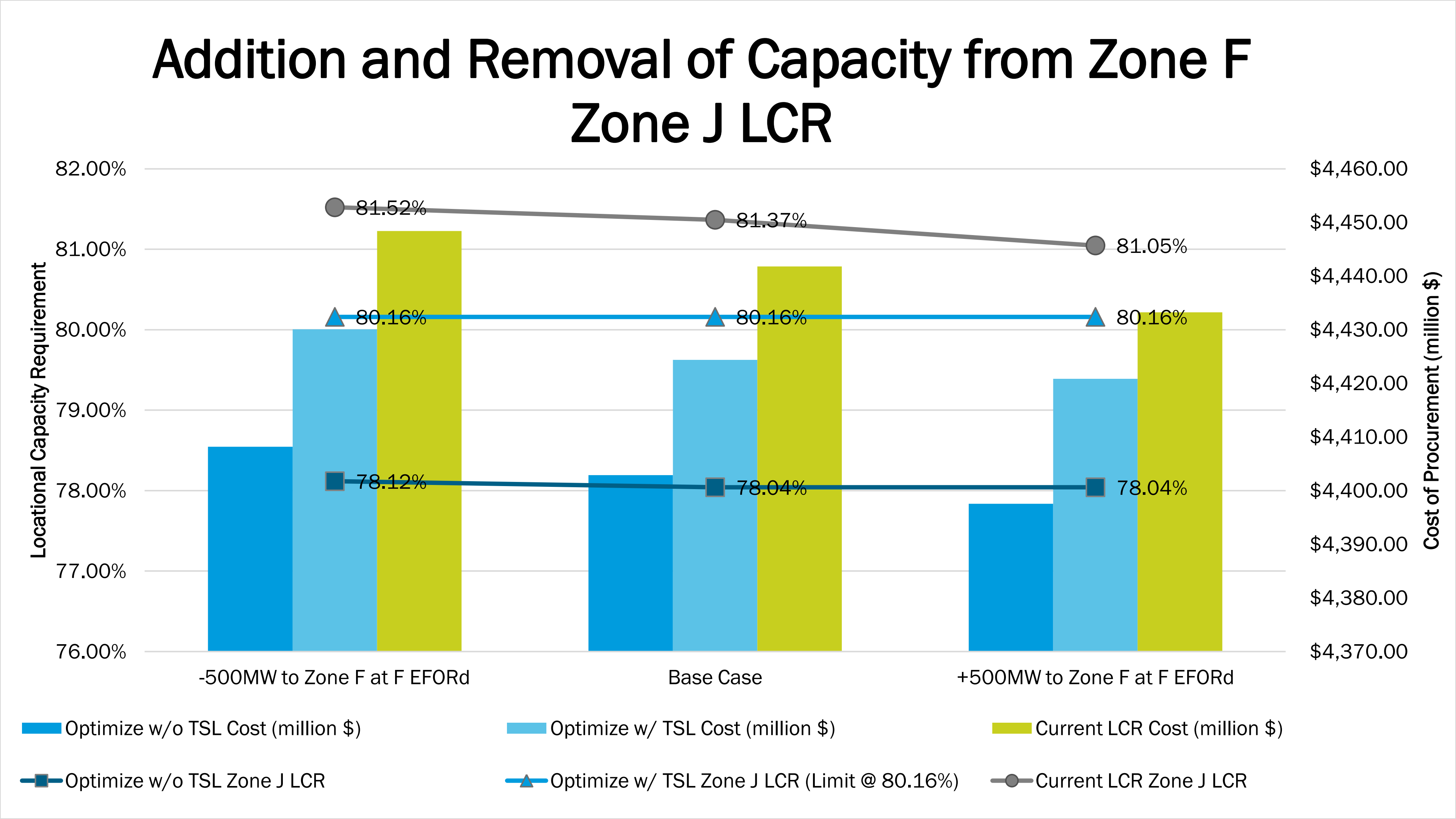
Addition and Removal of Capacity from Zone K
Zone K LCR



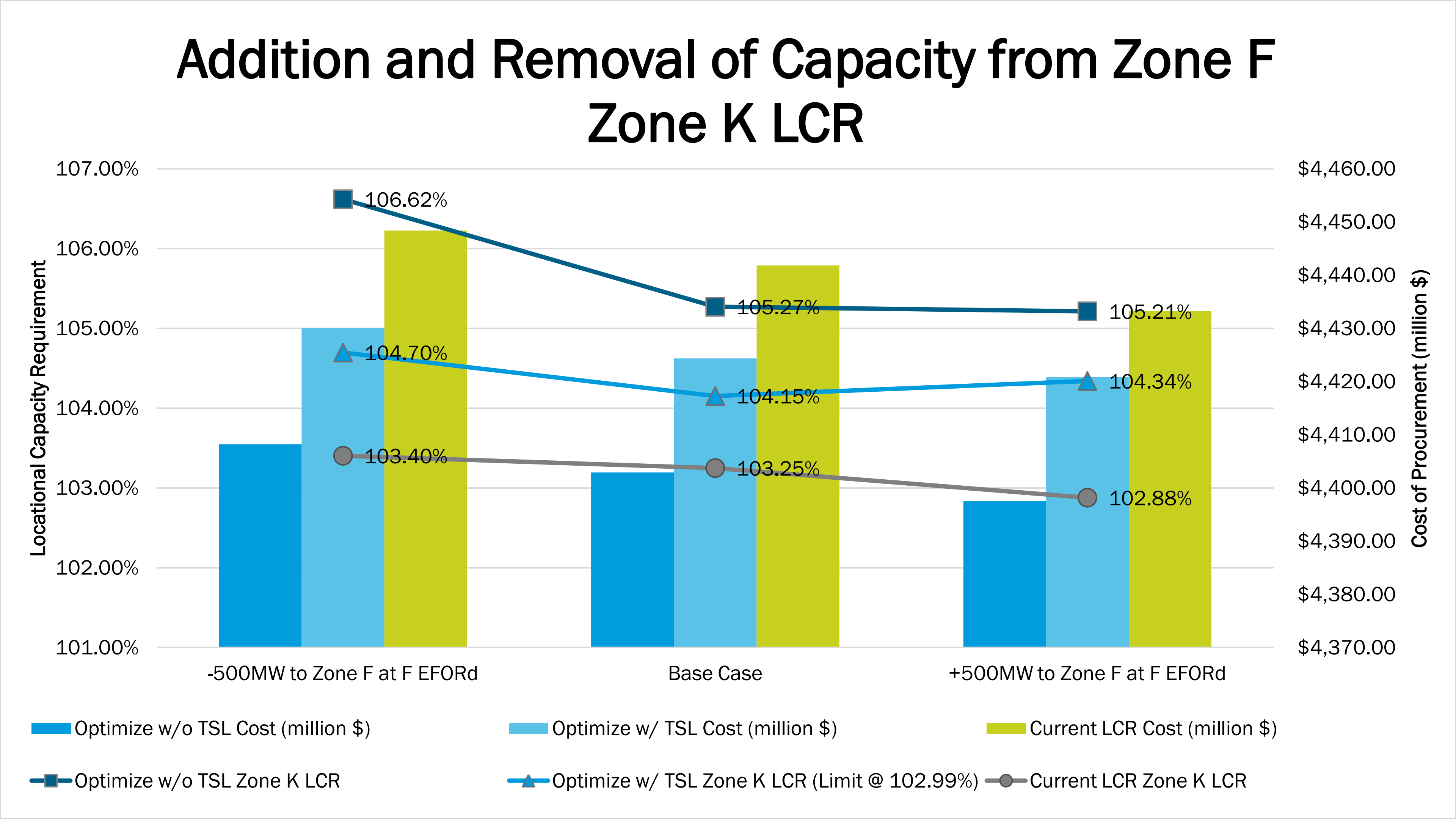
Addition and Removal of Capacity from Zone K G-J LCR



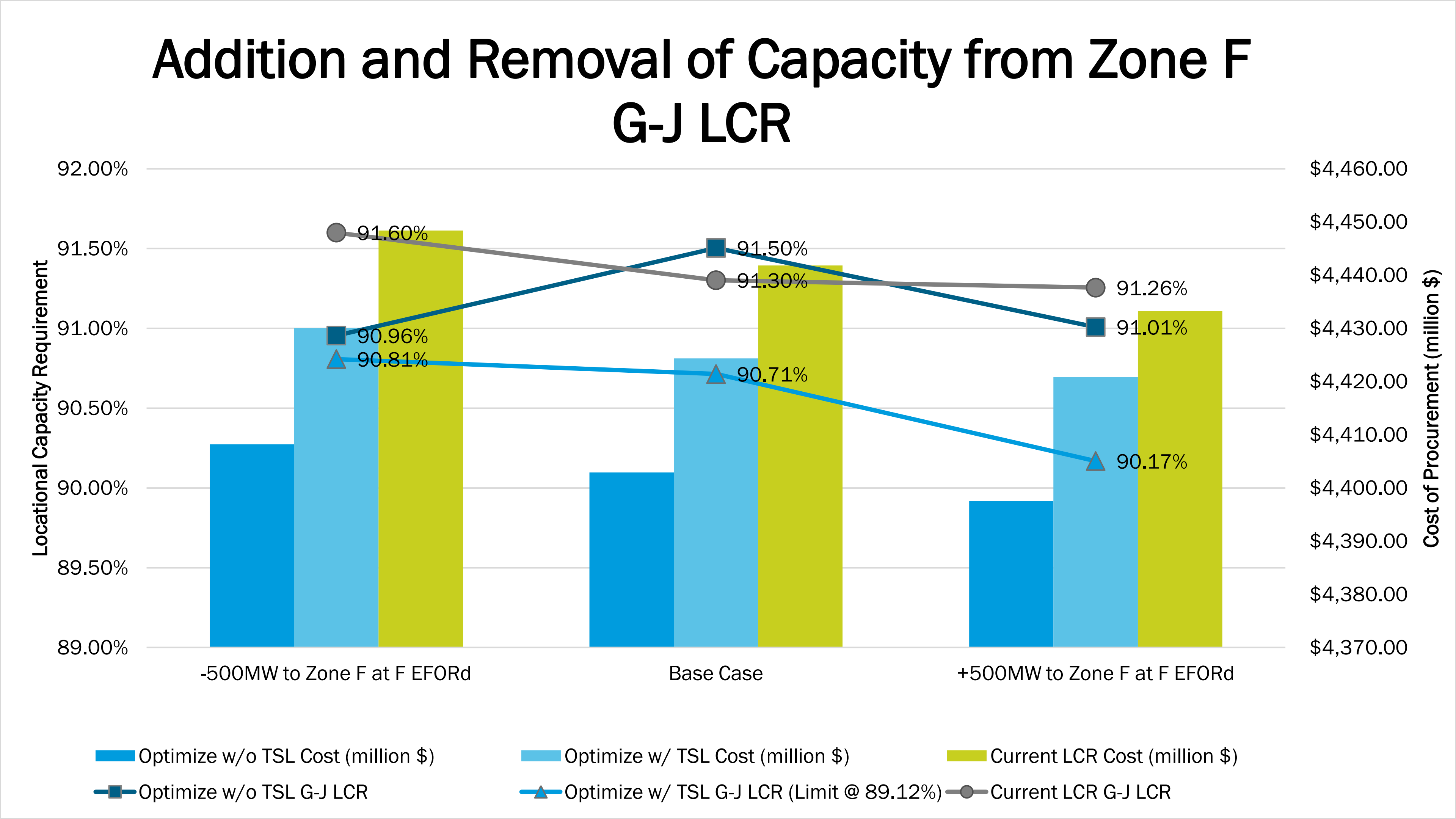
Market Simulations: +/- 500 MW to Zone F



Addition and Removal of Capacity from Zone F
Zone J LCR
Locational Capacity Requirement
Cost of Procurement (million $)
82.00%
81.00%
80.00%
79.00%
78.00%
77.00%
76.00%
$4,460.00
$4,450.00
$4,440.00
$4,430.00
$4,420.00
$4,410.00
$4,400.00
$4,390.00
$4,380.00
$4,370.00
81.52%
81.37%
81.05%
80.16%
80.16%
80.16%
78.12%
78.04%
78.04%
-500MW to Zone F at F EFORd
Base Case
+500MW to Zone F at F EFORd
Optimize w/o TSL Cost (million $)
Optimize w/ TSL Cost (million $)
Current LCR Cost (million $)
Optimize w/o TSL Zone J LCR
Optimize w/ TSL Zone J LCR (Limit @ 80.16%)
Current LCR Zone J LCR



Addition and Removal of Capacity from Zone F
Zone K LCR
107.00%
106.00%
105.00%
104.00%
103.00%
102.00%
101.00%
Locational Capacity Requirement
$4,460.00
$4,450.00
$4,440.00
$4,430.00
$4,420.00
$4,410.00
$4,400.00
$4,390.00
$4,380.00
$4,370.00
Cost of Procurement (million $)
106.62%
105.27%
105.21%
104.70%
104.15%
104.34%
103.40%
103.25%
102.88%
-500MW to Zone F at F EFORd
Base Case
+500MW to Zone F at F EFORd
Optimize w/o TSL Cost (million $)
Optimize w/ TSL Cost (million $)
Current LCR Cost (million $)
Optimize w/o TSL Zone K LCR
Optimize w/ TSL Zone K LCR (Limit @ 102.99%)
Current LCR Zone K LCR



Addition and Removal of Capacity from Zone F
G-J LCR
Locational Capacity Requirement
Cost of Procurement (million $)
92.00%
91.50%
91.00%
90.50%
90.00%
89.50%
89.00%
$4,460.00
$4,450.00
$4,440.00
$4,430.00
$4,420.00
$4,410.00
$4,400.00
$4,390.00
$4,380.00
$4,370.00
91.60%
90.96%
90.81%
91.50%
91.30%
90.71%
91.26%
91.01%
90.17%
-500MW to Zone F at F EFORd
Base Case
+500MW to Zone F at F EFORd
Optimize w/o TSL Cost (million $)
Optimize w/ TSL Cost (million $)
Current LCR Cost (million $)
Optimize w/o TSL G-J LCR
Optimize w/ TSL G-J LCR (Limit @ 89.12%)
Current LCR G-J LCR

Multiple Changes in Generation

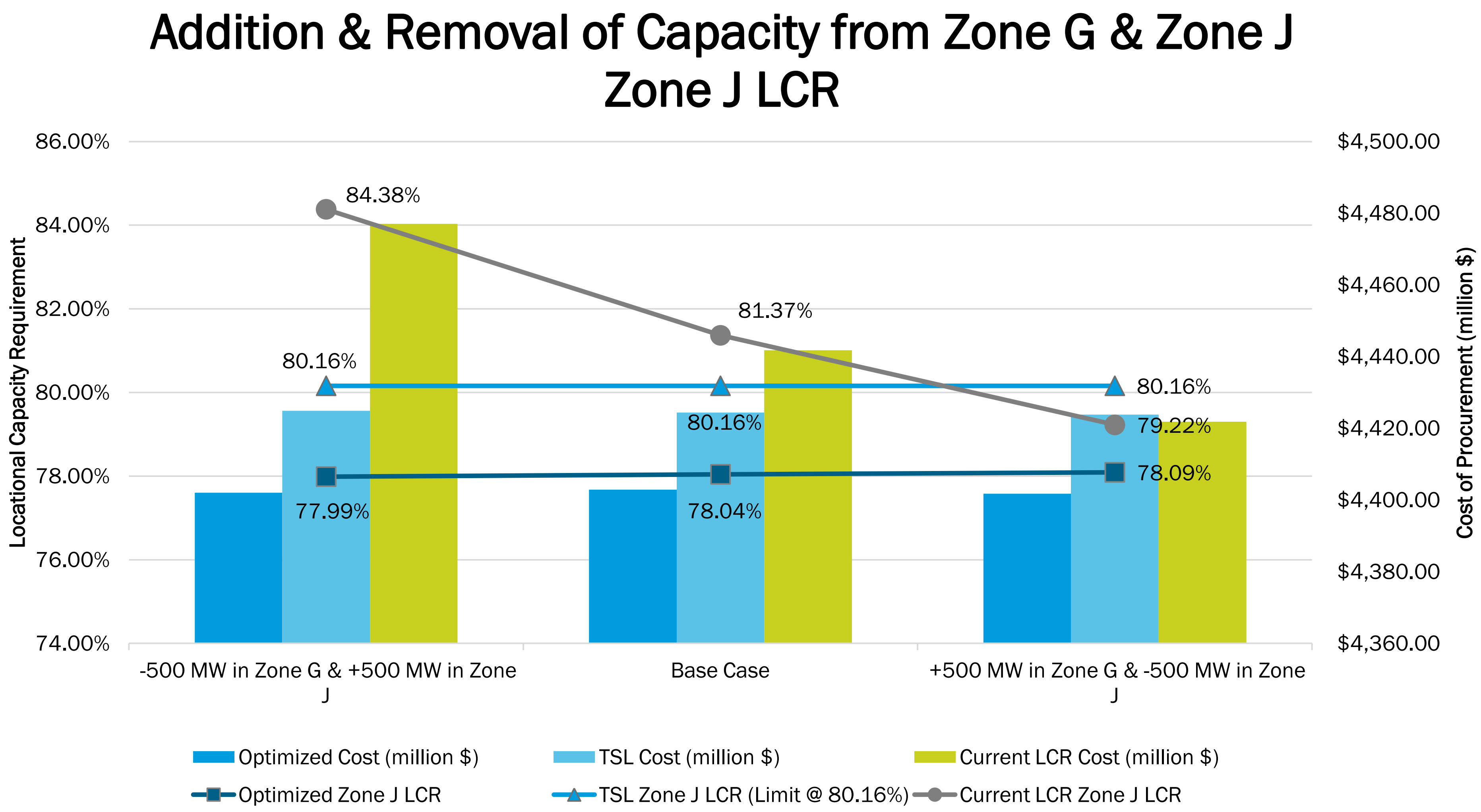
- +500 MW in Zone G & -500 MW in Zone J
- -500 MW in Zone G & +500 MW in Zone J
- +500 MW in Zone K & -500 MW in Zone J
- -500 MW in Zone K & +500 MW in Zone J

NEW YORK INDEPENDENT SYSTEM OPERATOR

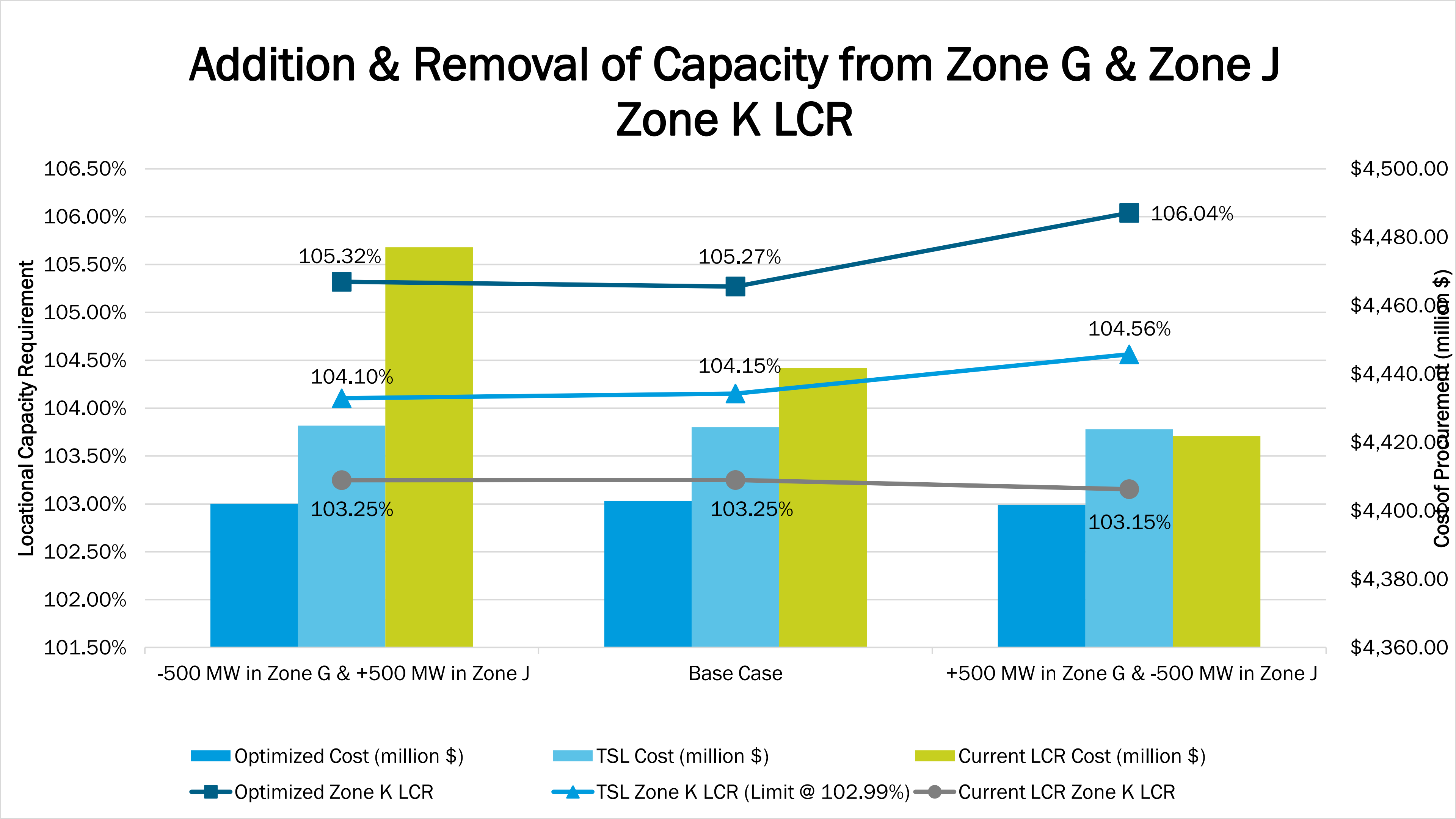
Market Simulations: +/- 500 MW to Zone G and +/-500 MW to Zone J

NEW YORK INDEPENDENT SYSTEM OPERATOR

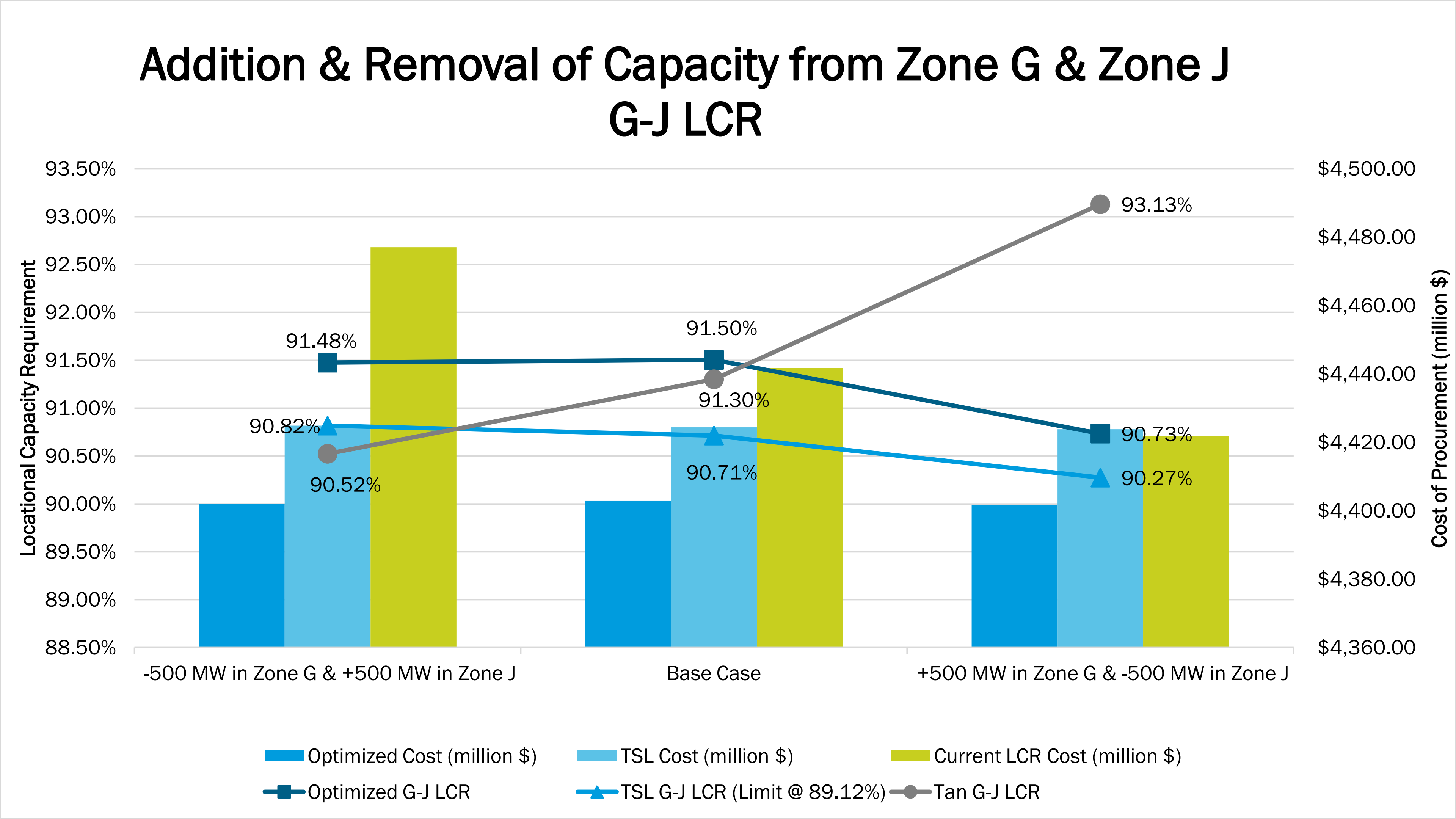
DRAFT – FOR DISCUSSION PURPOSES ONLY



Addition & Removal of Capacity from Zone G & Zone J
Zone J LCR
86.00%
84.00%
82.00%
80.00%
78.00%
76.00%
74.00%
Locational Capacity Requirement
$4,500.00
$4,480.00
$4,460.00
$4,440.00
$4,420.00
$4,400.00
$4,380.00
$4,360.00
Cost of Procurement (million $)
84.38%
81.37%
80.16%
80.16%
80.16%
79.22%
78.09%
77.99%
78.04%
-500 MW in Zone G & +500 MW in Zone J
Base Case
+500 MW in Zone G & -500 MW in Zone J
Optimized Cost (million $)
TSL Cost (million $)
Current LCR Cost (million $)
Optimized Zone J LCR
TSL Zone J LCR (Limit @ 80.16%)
Current LCR Zone J LCR



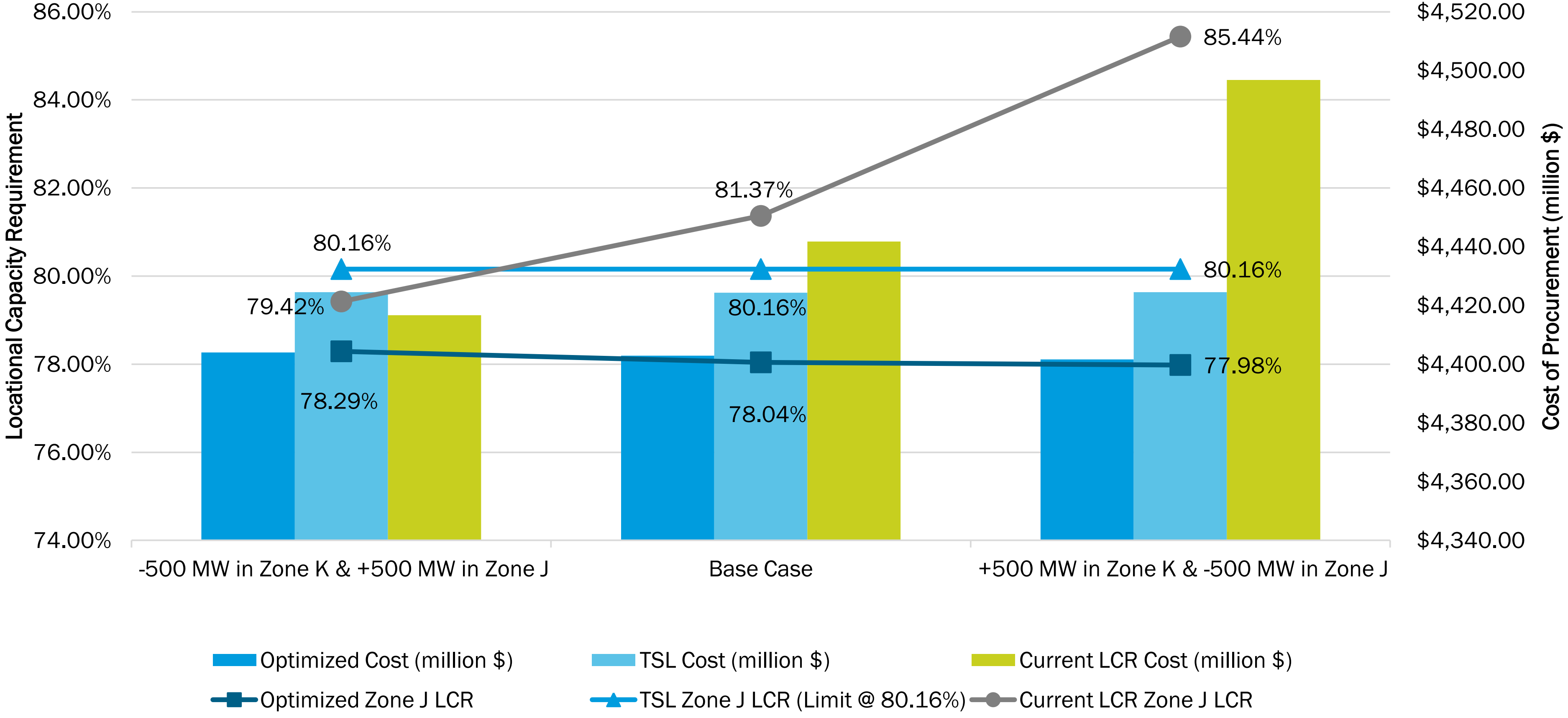
Addition & Removal of Capacity from Zone G & Zone J
Zone K LCR
Locational Capacity Requirement
Cost of Procurement (million $)
106.50%
106.00%
105.50%
105.00%
104.50%
104.00%
103.50%
103.00%
102.50%
102.00%
101.50%
$4,500.00
$4,480.00
$4,460.00
$4,440.00
$4,420.00
$4,400.00
$4,380.00
$4,360.00
105.32%
105.27%
106.04%
104.10%
104.15%
104.56%
103.25%
103.25%
103.15%
-500 MW in Zone G & +500 MW in Zone J
Base Case
+500 MW in Zone G & -500 MW in Zone J
Optimized Cost (million $)
TSL Cost (million $)
Current LCR Cost (million $)
Optimized Zone K LCR
TSL Zone K LCR (Limit @ 102.99%)
Current LCR Zone K LCR

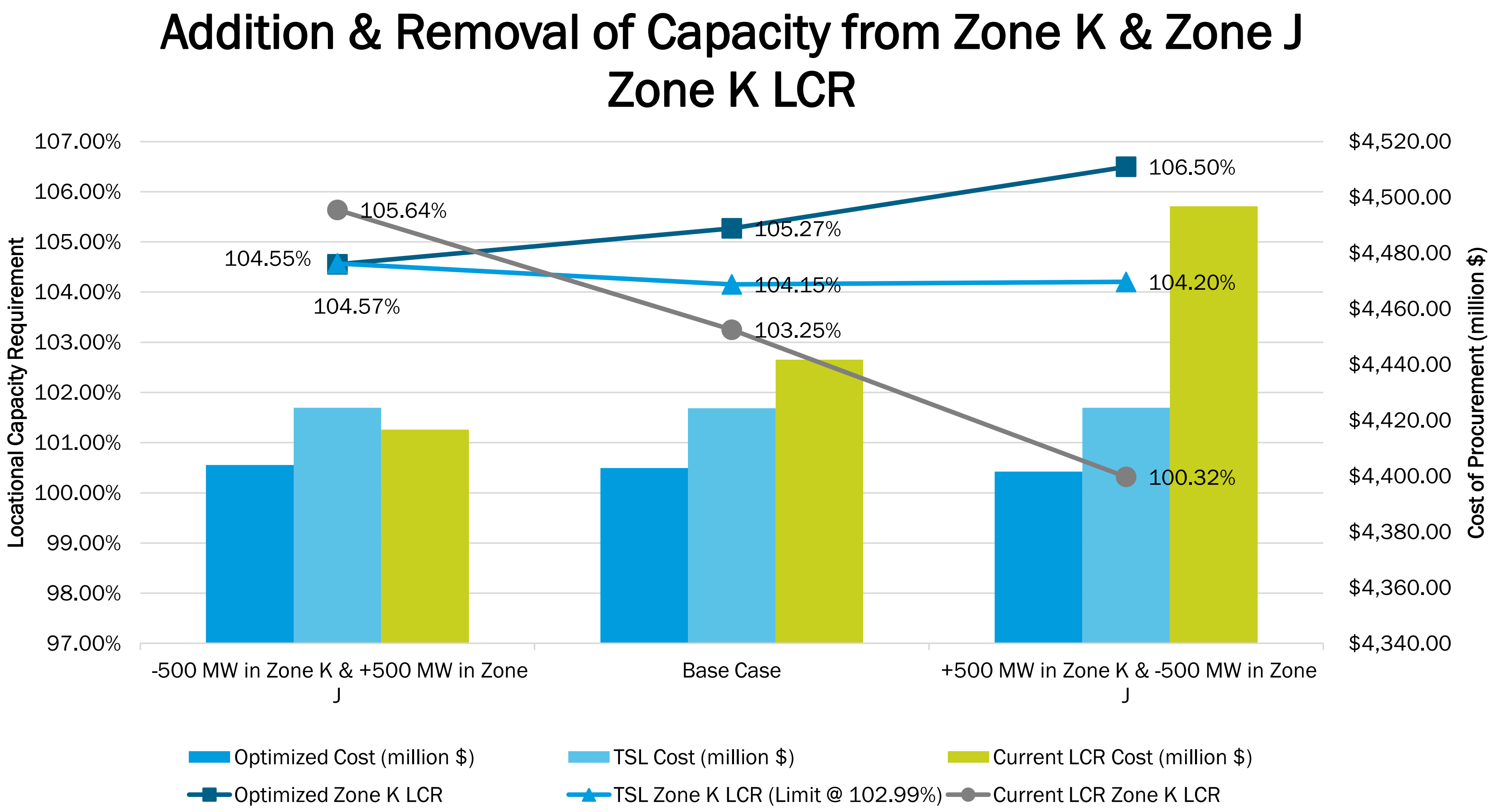


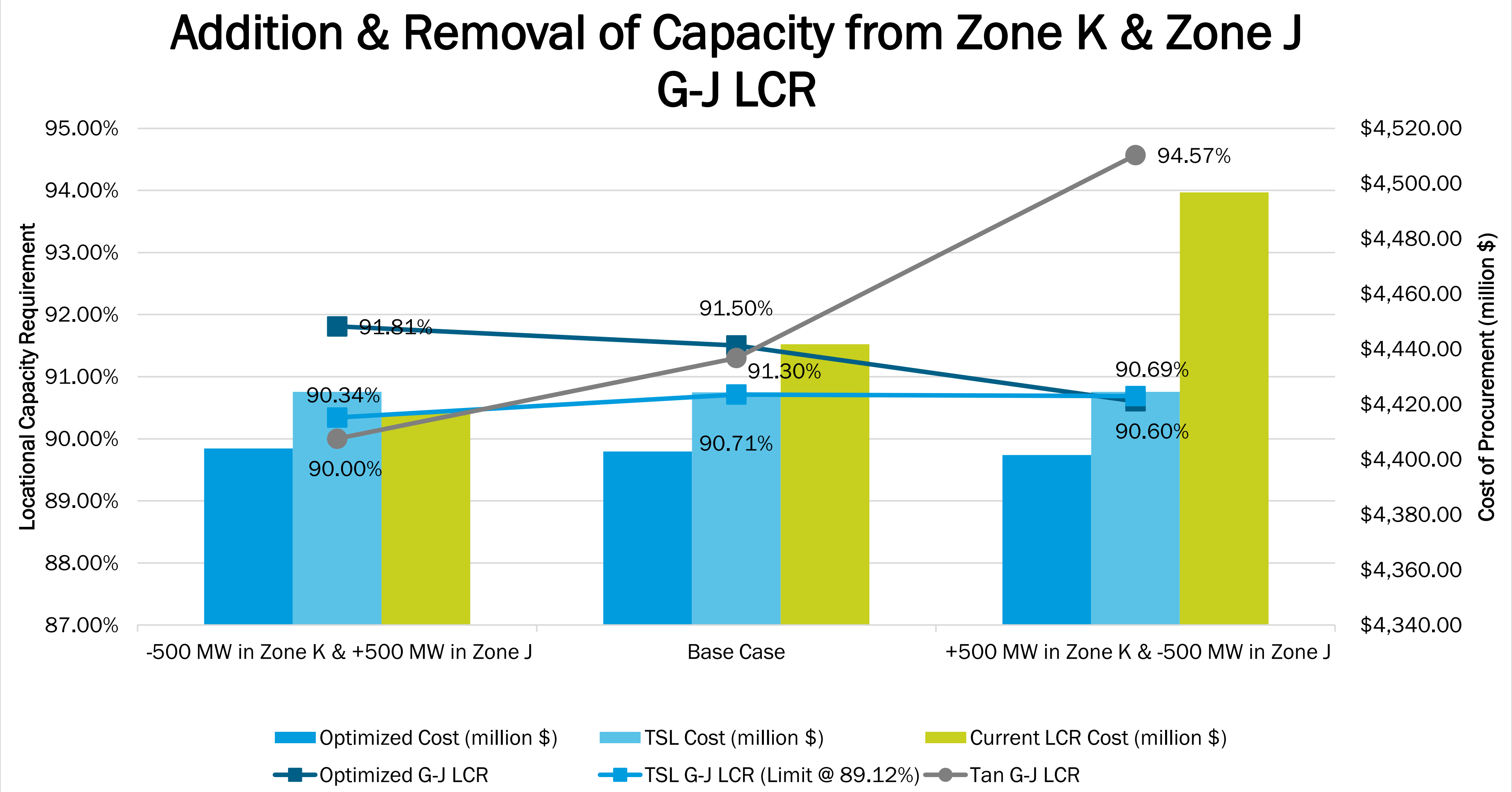
Addition & Removal of Capacity from Zone G & Zone J
G-J LCR
Locational Capacity Requirement
Cost of Procurement (million $)
93.50%
93.00%
92.50%
92.00%
91.50%
91.00%
90.50%
90.00%
89.50%
89.00%
88.50%
$4,500.00
$4,480.00
$4,460.00
$4,440.00
$4,420.00
$4,400.00
$4,380.00
$4,360.00
91.48%
90.82%
90.52%
91.50%
91.30%
90.71%
93.13%
90.73%
90.27%
-500 MW in Zone G & +500 MW in Zone J
Base Case
+500 MW in Zone G & -500 MW in Zone J
Optimized Cost (million $)
TSL Cost (million $)
Current LCR Cost (million $)
Optimized G-J LCR
TSL G-J LCR (Limit @ 89.12%)
Tan G-J LCR

Market Simulations: +/- 500 MW to Zone K and +/-500 MW to Zone J

Addition & Removal of Capacity from Zone K & Zone J
Zone J LCR




Addition & Removal of Capacity from Zone K & Zone J
Zone K LCR
Locational Capacity Requirement
Cost of Procurement (million $)
107.00%
106.00%
105.00%
104.00%
103.00%
102.00%
101.00%
100.00%
99.00%
98.00%
97.00%
$4,520.00
$4,500.00
$4,480.00
$4,460.00
$4,440.00
$4,420.00
$4,400.00
$4,380.00
$4,360.00
$4,340.00
106.50%
105.64%
105.27%
104.55%
104.15%
104.20%
104.57%
103.25%
100.32%
-500 MW in Zone K & +500 MW in Zone J
Base Case
+500 MW in Zone K & -500 MW in Zone J
Optimized Cost (million $)
TSL Cost (million $)
Current LCR Cost (million $)
Optimized Zone K LCR
TSL Zone K LCR (Limit @ 102.99%)
Current LCR Zone K LCR



Addition & Removal of Capacity from Zone K & Zone J
G-J LCR
Locational Capacity Requirement
Cost of Procurement (million $)
95.00%
94.00%
93.00%
92.00%
91.00%
90.00%
89.00%
88.00%
87.00%
$4,520.00
$4,500.00
$4,480.00
$4,460.00
$4,440.00
$4,420.00
$4,400.00
$4,380.00
$4,360.00
$4,340.00
94.57%
91.81%
91.50%
91.30%
90.69%
90.34%
90.71%
90.60%
90.00%
-500 MW in Zone K & +500 MW in Zone J
Base Case
+500 MW in Zone K & -500 MW in Zone J
Optimized Cost (million $)
TSL Cost (million $)
Current LCR Cost (million $)
Optimized G-J LCR
TSL G-J LCR (Limit @ 89.12%)
Tan G-J LCR

Changes in Transmission

Changes in Transmission

- **+1000 MW to UPNY-SENY**
  - Transmission Security Limit for G-J was recalculated assuming an additional 1000 MW of import capability

+1000 MW to UPNY-SENY

Scenario	Zone J LCR	Zone K LCR	G-J LCR	Cost ($ million)
Current LCR Methodology	79.38%	101.94%	90.18%	$ 4,398.63
Optimized Methodology without Transmission Security Limits (TSL)	77.71%	107.44%	84.29%	$4,365.16
Optimized Methodology with Transmission Security Limits (TSL)	**80.16%**	**103.80%**	**84.96%**	**$4,388.00**

- **G-J import limit was increased by 1000 MW in the TSL calculation resulting in a reduction in the TSL from 89.12% to 82.17%**

NEW YORK INDEPENDENT SYSTEM OPERATOR

+1000 MW to UPNY-SENY

Scenario	Zone J LCR	Zone K LCR	G-J LCR
Current LCR Methodology	9,263 MW	5,532 MW	14,484 MW
Optimized Methodology without Transmission Security Limits (TSL)	9,069 MW	5,831 MW	13,538 MW
Optimized Methodology with Transmission Security Limits (TSL)	9,355 MW	5,633 MW	13,645 MW

Change from Base Case to +1000 MW UPNY-SENY

Scenario	Δ Zone J MW	Δ Zone K MW	Δ G-J MW	Δ Total Locality MW
Current LCR Methodology	-232.2	-71.1	-180.5	-483.8
Optimized Methodology without Transmission Security Limits (TSL)	-38.5	117.7	-1159.1	-1079.9
Optimized Methodology with Transmission Security Limits (TSL)	0.0	-19.2	-924.8	-944.1

NEW YORK INDEPENDENT SYSTEM OPERATOR

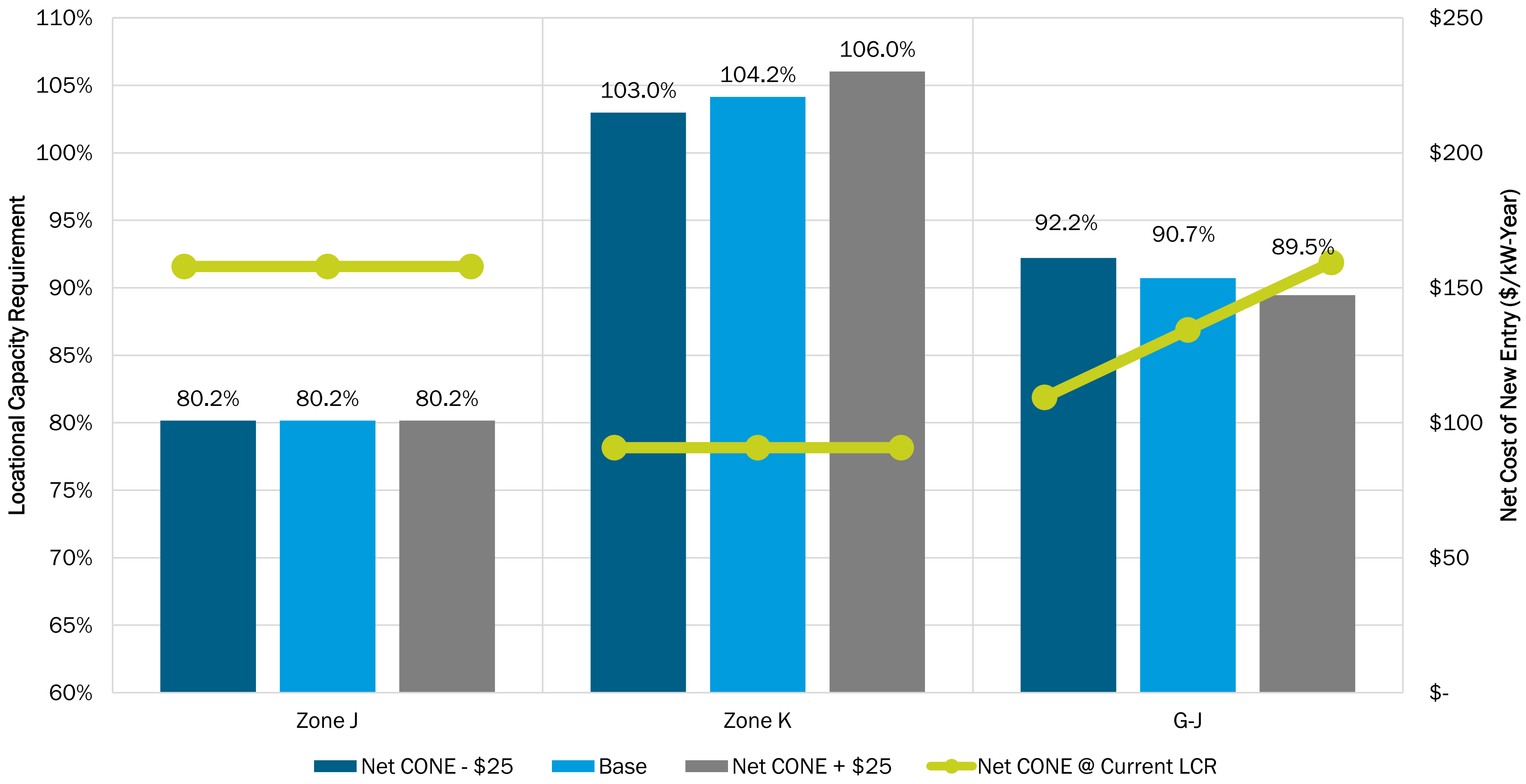
DRAFT – FOR DISCUSSION PURPOSES ONLY

Changes in Net CONE

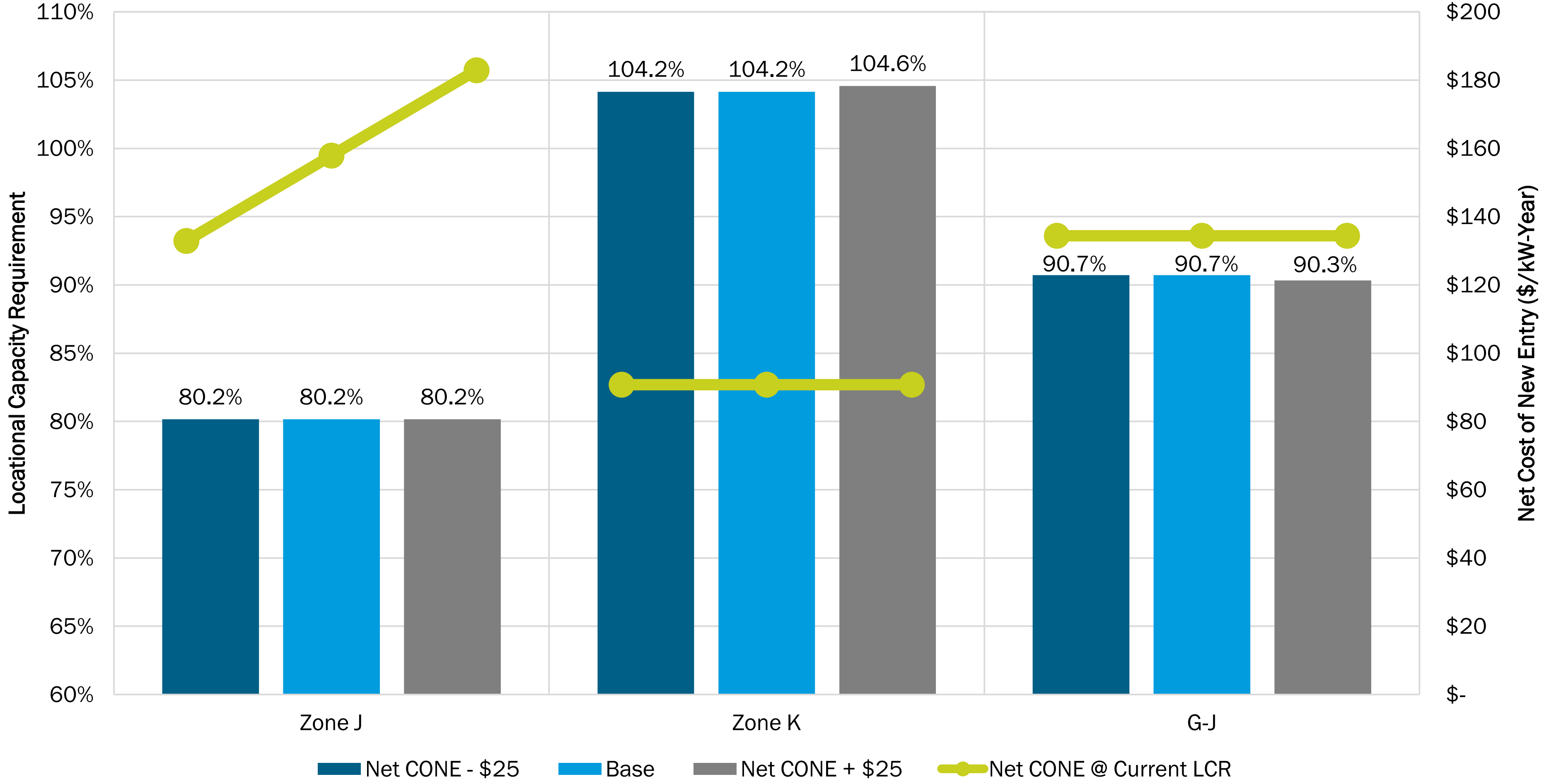
Changes in Net CONE

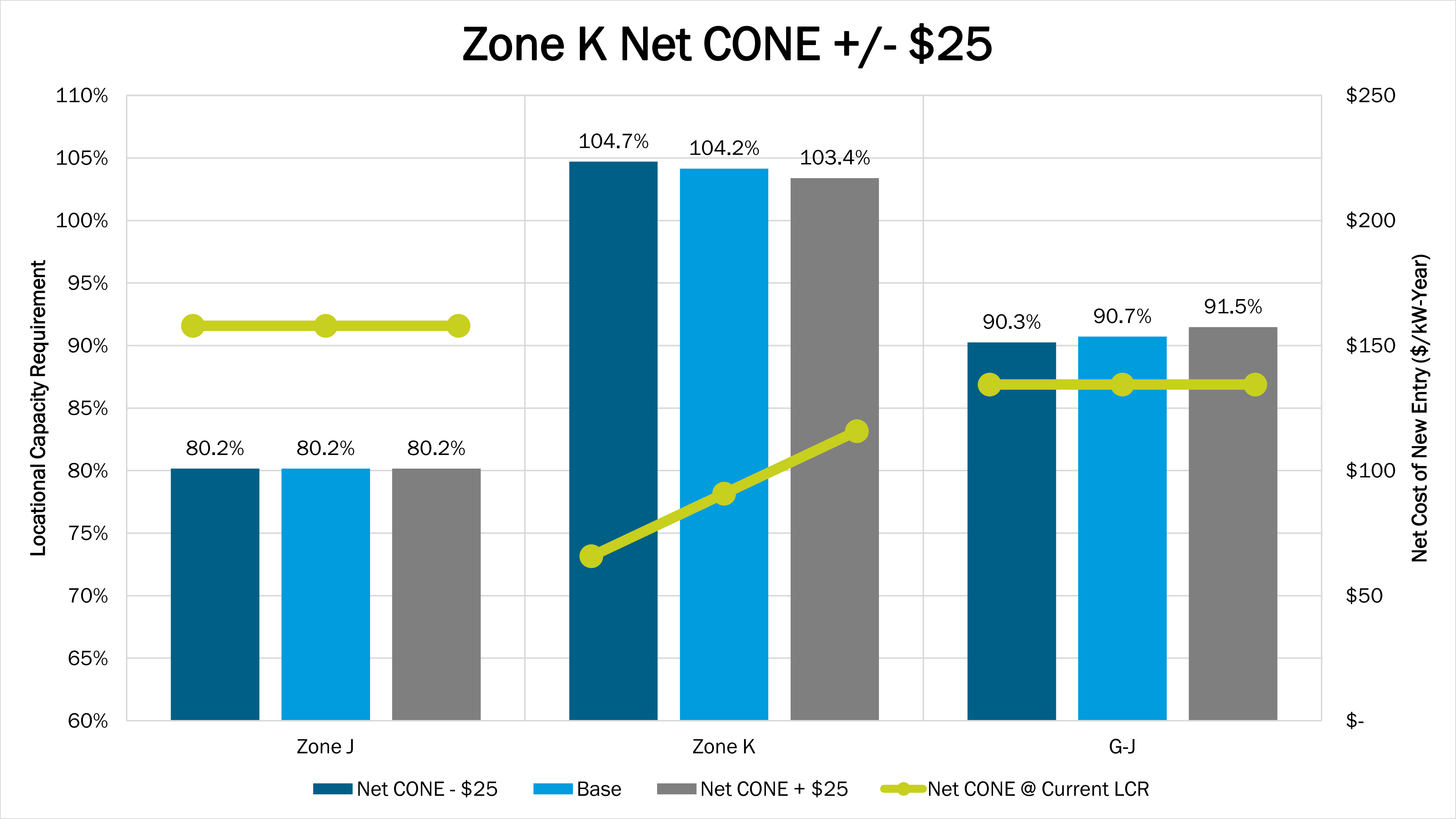
- +/- $25.00 to G-J Net CONE
- +/- $25.00 to Zone J Net CONE
- +/- $25.00 to Zone K Net CONE
- +/- $25.00 to NYCA Net CONE

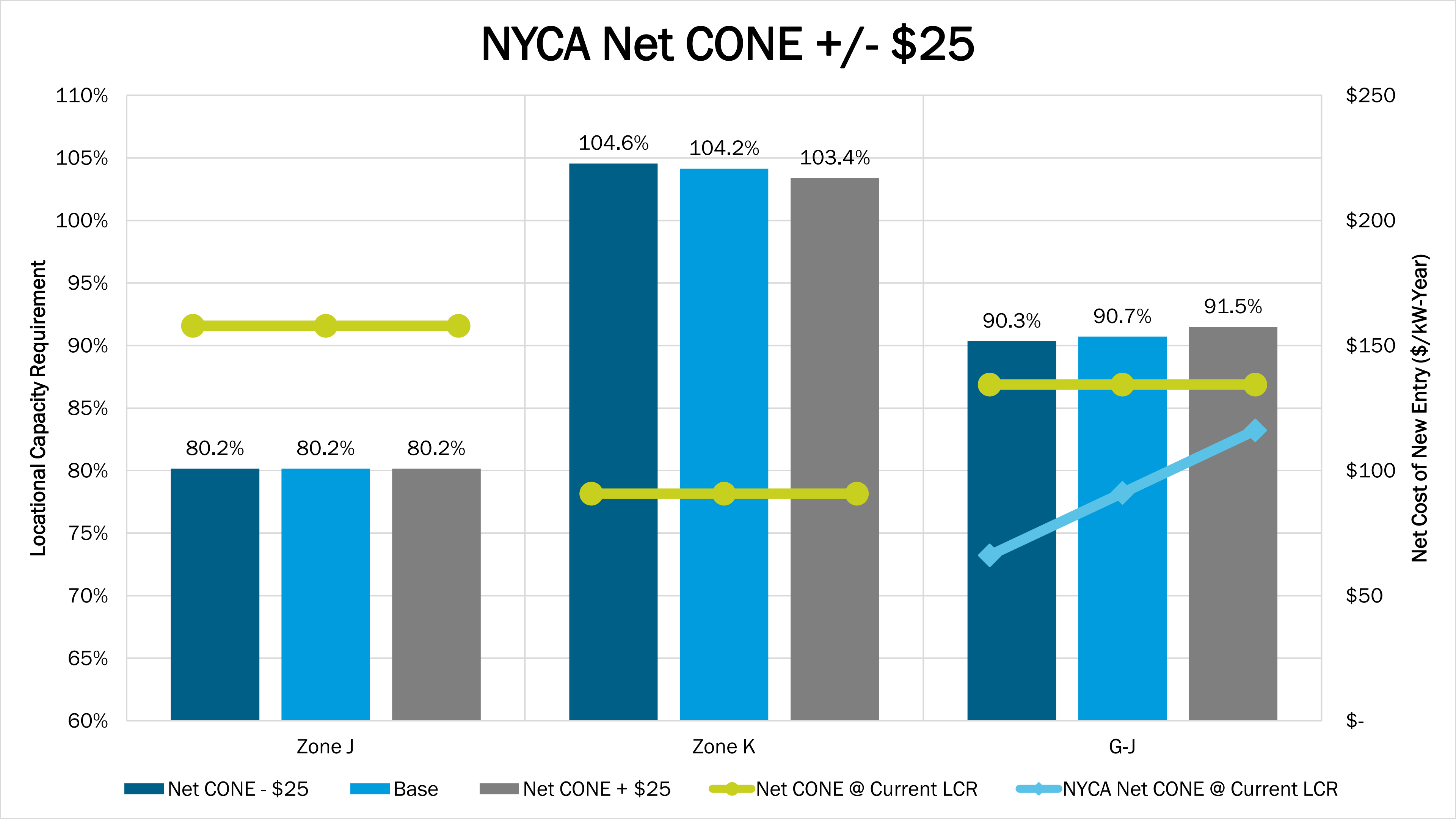
G-J Net CONE +/- $25



Zone J Net CONE +/- $25




Zone K Net CONE +/- $25
Locational Capacity Requirement
Net Cost of New Entry ($/kW-Year)
110%
105%
100%
95%
90%
85%
80%
75%
70%
65%
60%
$250
$200
$150
$100
$50
$-
80.2%
80.2%
80.2%
104.7%
104.2%
103.4%
90.3%
90.7%
91.5%
Zone J
Zone K
G-J
Net CONE - $25
Base
Net CONE + $25
Net CONE @ Current LCR


NYCA Net CONE +/- $25
Locational Capacity Requirement
110%
105%
100%
95%
90%
85%
80%
75%
70%
65%
60%
Net Cost of New Entry ($/kW-Year)
$250
$200
$150
$100
$50
$-
80.2%
80.2%
80.2%
104.6%
104.2%
103.4%
90.3%
90.7%
91.5%
Zone J
Zone K
G-J
Net CONE - $25
Base
Net CONE + $25
Net CONE @ Current LCR
NYCA Net CONE @ Current LCR

All Sensitivities

Scenario	Optimized LCR without Transmission Security Floors (%)			Optimized Cost (million)
	Zone J	Zone K	G-J	
Base Case	78.04%	105.27%	91.50%	$ 4,402.89
+500 MW to Zone G at G-J EFORd	78.11%	105.97%	90.76%	$ 4,401.96
-500 MW to Zone G at G-J EFORd	78.06%	105.93%	90.78%	$ 4,400.95
+500MW to Zone J at J EFORd	78.04%	105.27%	91.50%	$ 4,402.89
-500MW to Zone J at J EFORd	78.04%	105.27%	91.50%	$ 4,402.89
+500MW to Zone K at K EFORd	78.29%	104.55%	91.81%	$ 4,404.03
-500MW to Zone K at K EFORd	78.05%	105.99%	90.81%	$ 4,401.55
+500MW to Zone F at F EFORd	78.04%	105.21%	91.01%	$ 4,397.54
-500MW to Zone F at F EFORd	78.12%	106.62%	90.96%	$ 4,408.19

Scenario	Optimized LCR without Transmission Security Floors (%)			Optimized Cost (million)
	Zone J	Zone K	G-J	
+1000 MW to UPNYSENY	77.71%	107.44%	84.29%	$4,365.16
+$25.00 to G-J	78.11%	106.76%	90.23%	$4,536.54
-$25.00 to G-J	77.57%	106.01%	91.76%	$4,260.14
+$25.00 Zone J	77.48%	107.46%	90.76%	$4,632.05
-$25.00 to Zone J	78.13%	104.90%	91.67%	$4,169.45
+$25.00 to Zone K	78.10%	104.55%	92.09%	$4,550.71
-$25.00 to Zone K	77.60%	107.18%	90.83%	$4,250.47
+$25.00 to NYCA	77.46%	106.73%	91.46%	$4,863.41
-$25.00 to NYCA	78.25%	105.62%	90.77%	$3,936.72

Scenario	Optimized LCR without Transmission Security Floors (%)			Optimized Cost (million)
	Zone J	Zone K	G-J	
+500 MW in Zone G at G-J EFORd & -500 MW in Zone J at J EFORd	78.09%	106.04%	90.73%	$4,401.78
+500 MW in Zone K at K EFORd & -500 MW in Zone J at J EFORd	78.29%	104.55%	91.81%	$4,404.03
-500 MW in Zone G at G-J EFORd & +500 MW in Zone J at J EFORd	77.99%	105.32%	91.48%	$4,402.07
-500 MW in Zone K at K EFORd & +500 MW in Zone J at J EFORd	77.98%	106.50%	90.60%	$4,401.59

Scenario	Optimized LCR with Preliminary Transmission Security Floors (%)			Optimized Cost (million)
	Zone J	Zone K	G-J	
Base Case	80.16%	104.15%	90.71%	$4,424.37
+500 MW to Zone G at G-J EFORd	80.16%	104.56%	90.27%	$4,423.79
-500 MW to Zone G at G-J EFORd	80.16%	104.52%	90.40%	$4,424.65
+500MW to Zone J at J EFORd	80.16%	104.15%	90.71%	$4,424.37
-500MW to Zone J at J EFORd	80.16%	104.15%	90.71%	$4,424.37
+500MW to Zone K at K EFORd	80.16%	104.57%	90.34%	$4,424.52
-500MW to Zone K at K EFORd	80.16%	104.20%	90.69%	$4,424.55
+500MW to Zone F at F EFORd	80.16%	104.34%	90.17%	$4,420.83
-500MW to Zone F at F EFORd	80.16%	104.70%	90.81%	$4,430.07

Scenario	Optimized LCR with Preliminary Transmission Security Floors (%)			Optimized Cost (million)
	Zone J	Zone K	G-J	
+1000 MW to UPNYSENY	80.16%	103.80%	84.96%	$4,388.00
+$25.00 to G-J	80.16%	106.03%	89.45%	$4,553.59
-$25.00 to G-J	80.16%	102.99%	92.22%	$4,292.37
+$25.00 Zone J	80.16%	104.57%	90.34%	$4,663.81
-$25.00 to Zone J	80.16%	104.15%	90.71%	$4,185.05
+$25.00 to Zone K	80.16%	103.39%	91.48%	$4,570.88
-$25.00 to Zone K	80.16%	104.70%	90.26%	$4,277.37
+$25.00 to NYCA	80.16%	103.40%	91.50%	$4,890.94
-$25.00 to NYCA	80.16%	104.56%	90.35%	$3,955.84

Scenario	Optimized LCR with Preliminary Transmission Security Floors (%)			Optimized Cost (million)
	Zone J	Zone K	G-J	
+500 MW in Zone G at G-J EFORd & -500 MW in Zone J at J EFORd	80.16%	104.56%	90.27%	$4,423.79
+500 MW in Zone K at K EFORd & -500 MW in Zone J at J EFORd	80.16%	104.57%	90.34%	$4,424.52
-500 MW in Zone G at G-J EFORd & +500 MW in Zone J at J EFORd	80.16%	104.10%	90.82%	$4,424.92
-500 MW in Zone K at K EFORd & +500 MW in Zone J at J EFORd	80.16%	104.20%	90.69%	$4,424.55

Scenario	Current LCR Methodology (%)			Optimized Cost (million)
	Zone J	Zone K	G-J	
Base Case	81.4%	103.2%	91.3%	$ 4,441.80
+500 MW to Zone G at G-J EFORd	79.87%	102.37%	93.44%	$ 4,429.79
-500 MW to Zone G at G-J EFORd	83.52%	104.21%	89.86%	$ 4,470.71
+500MW to Zone J at J EFORd	81.94%	102.48%	91.94%	$ 4,450.11
-500MW to Zone J at J EFORd	80.38%	104.10%	90.73%	$ 4,428.17
+500MW to Zone K at K EFORd	80.14%	104.48%	90.46%	$ 4,424.31
-500MW to Zone K at K EFORd	84.43%	100.67%	93.78%	$ 4,482.72
+500MW to Zone F at F EFORd	81.05%	102.88%	91.26%	$ 4,433.26
-500MW to Zone F at F EFORd	81.52%	103.40%	91.60%	$ 4,448.38

Scenario	Current LCR Methodology (%)			Optimized Cost (million)
	Zone J	Zone K	G-J	
+1000 MW to UPNYSENY	79.38%	101.94%	90.18%	$ 4,398.63
+500 MW in Zone G at G-J EFORd & -500 MW in Zone J at J EFORd	79.22%	103.15%	93.13%	$ 4,421.80
+500 MW in Zone K at K EFORd & -500 MW in Zone J at J EFORd	79.42%	105.64%	90.00%	$ 4,416.64
-500 MW in Zone G at G-J EFORd & +500 MW in Zone J at J EFORd	84.38%	103.25%	90.52%	$ 4,477.06
-500 MW in Zone K at K EFORd & +500 MW in Zone J at J EFORd	85.44%	100.32%	94.57%	$ 4,496.80

NEW YORK INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY

Exhibit 31

Alternative Method for Determining LCRs

Zachary Stines
Associate Market Design Specialist

Installed Capacity Working Group

January 10, 2018, NYISO

NEW YORK INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY

Agenda

- Net CONE Curves
- 2018 Project Timeline
- Next Steps
- Questions

Net CONE Curves

Net CONE Curves

- **Recommend the use of uncollared Net CONE in the optimized method for determining LCRs**
  - Collaring of Net CONE will sunset in 2021
  - Uncollared Net CONE is representative of the cost of building capacity in a region
  - Uncollared Net CONE sends efficient investment signals

2018 Project Timeline

2018 Project Plan

- January 16 – Return to MIWG/ICAPWG with draft Tariff language
- February 14 –Presentation to BIC of Tariff language and propose for stakeholder vote
- February 28 – Present to MC for stakeholder vote
- February /March – Present hypothetical 2018 Optimized LCRs
- March – File with FERC a Section 205 to amend tariff
- Summer – Update documentation/procedures
- January 2019 – Implementation of new methodology (i.e., LCRs for 2019/2020 Capability Year)

Next Steps

Other Next Steps

- The NYISO will consider input received during today's ICAP Working Group meeting
- Return with Tariff language
- Additional comments sent to deckels@nyiso.com will be considered

NEW YORK INDEPENDENT SYSTEM OPERATOR

Questions?

The Mission of the New York Independent System Operator, in collaboration with its stakeholders, is to serve the public interest and provide benefits to consumers by:

- Maintaining and enhancing regional reliability
- Operating open, fair and competitive wholesale electricity markets
- Planning the power system for the future
- Providing factual information to policy makers, stakeholders and investors in the power system

www.nyiso.com

NEW YORK INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY

Exhibit 32

Alternative Method for Determining LCRs

Zachary Stines
Associate Market Design Specialist

Installed Capacity Working Group

January 25, 2018, NYISO

NEW YORK INDEPENDENT SYSTEM OPERATOR

Agenda

- 2018 Optimized LCR Sensitivities
- Tariff
- Next Steps
- Questions

2018 Optimized LCR Sensitivities

2018 Optimized LCR Sensitivities

- Performed the alternative methodology on the 2018 Final IRM case with
  - 2018 Transmission Security Limits
  - 2018 Net CONE curves (e.g., collared and uncollared)

2018 Transmission Security Limits

Transmission Security Requirements	G-J	Zone J	Zone K
Load Forecast (MW)	15,890	11,541	5,445
Transmission Security Import Limit (MW)	3,000	3,175	350
Transmission Security UCAP Requirement (MW)	12,890	8,366	5,095
Transmission Security UCAP Requirement (%)	81.1%	72.5%	93.6%
5 Year EFORd (%)	9.55%	9.05%	9.26%
Transmission Security ICAP Requirement (MW)	14,250	9,198	5,615
Transmission Security LCR Floor (%)	**89.7%**	**79.7%**	**103.1%**

NEW YORK INDEPENDENT SYSTEM OPERATOR

2018 Optimized LCR Sensitivities

	G-J LCR	Zone J LCR	Zone KLCR
2018 Approved LCRs	94.5%	80.5%	103.5%
2018 Optimized LCR with Uncollared Net CONE Curves	90.8%	79.7%	107.5%
2018 Optimized LCR with Collared Net CONE Curves	90.5%	79.7%	108.2%

- **Sensitivities used**
  - 2018 IRM Base Case
  - 2018 Transmission Security Limits

2018 Optimized LCR Sensitivities

	G-J LCR	Zone J LCR	Zone KLCR
2018 Optimized LCR with Uncollared Net CONE Curves	14,432 MW	9,198 MW	5,856 MW
2018 Optimized LCR with Collared Net CONE Curves	14,375 MW	9,198 MW	5,892 MW
Difference	-57 MW	0 MW	36 MW

- Sensitivities and MW presented are based on 2018 IRM Load Forecast

NEW YORK INDEPENDENT SYSTEM OPERATOR

2018 Optimized LCR Sensitivities

	G-J LCR	Zone J LCR	Zone KLCR
Approved 2018 LCRs	15,043 MW	9,289 MW	5,606 MW
2018 Optimized LCR with Uncollared Net CONE Curves	14,457 MW	9,197 MW	5,825 MW
Difference	-585 MW	-92 MW	219 MW

- **While the approved 2018 LCRs and the 2018 Optimized LCR sensitivities utilized different load forecast (i.e., Sensitivities were based on the 2018 IRM load forecast), the MW presented here are based on the 2018 LCR load forecast for comparison purposes**
  - Differences in load forecast are presented in Appendix
- **The alternative methodology determines optimized LCRs that minimized total cost and resulted in lower total capacity requirements in zones G-K than the current method**

NEW YORK INDEPENDENT SYSTEM OPERATOR

Tariff

Updates

- Incremental revisions to the tariff redlines presented at the January 16 ICAPWG meeting are highlighted in yellow in the version posted with today's meeting material

Next Steps

Other Next Steps

- The NYISO will consider input received during today's ICAP Working Group meeting
- BIC on February 14th
- Additional comments sent to deckels@nyiso.com will be considered

NEW YORK INDEPENDENT SYSTEM OPERATOR

Questions?

The Mission of the New York Independent System Operator, in collaboration with its stakeholders, is to serve the public interest and provide benefits to consumers by:

- Maintaining and enhancing regional reliability
- Operating open, fair and competitive wholesale electricity markets
- Planning the power system for the future
- Providing factual information to policy makers, stakeholders and investors in the power system

www.nyiso.com

Appendix

Load Adjustments for ICAP Forecast

Area	Final 2018 IRM Study Load Forecast (MW) (10/2017)	Final 2018 ICAP/LCR Load Forecast (MW) (12/2017)	Change (MW)
Zone J (NYC)	11,541	11,539	-2
Zone K (LI)	5,445	5,416	-29
The G-J Locality	15,890	15,918	+28
NYCA	32,868	32,943	+75

NEW YORK INDEPENDENT SYSTEM OPERATOR

Exhibit 33

5.11 Requirements Applicable to LSEs

5.11.1 Allocation of the NYCA Minimum Unforced Capacity Requirement

Each Transmission Owner and each municipal electric utility will submit to the ISO, for its review pursuant to mutually agreed upon procedures which shall be described in the ISO Procedures, the weather-adjusted Load within its Transmission District during the hour in which actual Load in the NYCA was highest (the "NYCA peak Load") for the current Capability Year. (Municipal electric utilities may elect not to submit weather-adjusted data, in which case, weather adjustments shall be performed per ISO procedures. The ISO shall use these data to determine the Adjusted Actual Load at the time of the NYCA peak Load for each Transmission District and municipal electric utility pursuant to ISO Procedures, which shall ensure that transmission losses and the effects of demand reduction programs and the other elements of Adjusted Actual Load are treated in a consistent manner and that all weather normalization procedures meet a minimum criterion described in the ISO Procedures. Each Transmission District or municipal electric utility Load forecast coincident with the NYCA peak shall be the product of that Transmission District or municipal electric utility's Adjusted Actual Load at the time of the NYCA peak Load multiplied by one plus the regional Load growth factor for that Transmission District or municipal electric utility developed pursuant to Section 5.10 of this Tariff. After calculating each Transmission District or municipal electric utility Load forecast, if the ISO determines that an Adjusted Actual Load determined for a Transmission District or municipal electric utility does not reflect reasonable expectations of what Load might reasonably have been expected to occur in that Transmission District or area served by that municipal electric utility in that Capability Year, after taking into consideration the adjustments to account for weather normalization, transmission losses and demand response programs and other

elements of Adjusted Actual Load that are described in the ISO Procedures, the ISO Procedures shall also authorize the ISO to substitute its own measures of Adjusted Actual Load for that Transmission District or area serviced by that municipal electric utility in this calculation, subject to the outcome of dispute resolution procedures if invoked. The ISO's measure of Adjusted Actual Load shall be binding unless otherwise determined as the result of dispute resolution procedures that may be invoked. Each Transmission Owner must also submit aggregate Adjusted Load data, coincident with the NYCA peak hour, for all customers served by each LSE active within its Transmission District. The aggregate Load data may be derived from direct meters or Load profiles of the customers served. Each Transmission Owner shall be required to submit such forecasts and aggregate peak Load data in accordance with the ISO Procedures. Each municipal electric utility may choose to submit its peak Load forecast based on the Transmission District's peak Load forecast provided by a Transmission Owner or to provide its own. Any disputes arising out of the submittals required in this paragraph shall be resolved through the Expedited Dispute Resolution Procedures set forth in Section 5.17 of this Tariff.

All aggregate Load data submitted by a Transmission Owner must be accompanied by documentation indicating that each affected LSE has been provided the data regarding the assignment of customers to the affected LSE. Any disputes between LSEs and Transmission Owners regarding such data or assignments shall be resolved through the Expedited Dispute Resolution Procedures set forth in Section 5.17 of this Tariff, or the Transmission Owner's retail access procedures, as applicable.

The ISO shall allocate the NYCA Minimum Unforced Capacity Requirement among all LSEs serving Load in the NYCA prior to the beginning of each Capability Year. It shall then adjust the NYCA Minimum Unforced Capacity Requirement and reallocate it among LSEs

before each Winter Capability Period as necessary to reflect changes in the factors used to translate ICAP requirements into Unforced Capacity requirements. Each LSE's share of the NYCA Minimum Unforced Capacity Requirement will equal the product of: (i) the NYCA Minimum Installed Capacity Requirement as translated into a NYCA Minimum Unforced Capacity Requirement; and (ii) the ratio of the sum of the Load forecasts coincident with the NYCA peak Load for that LSE's customers in each Transmission District to the NYCA peak Load forecast.

Each LSE Unforced Capacity Obligation will equal the product of (i) the ratio of that LSE's share of the NYCA Minimum Unforced Capacity Requirement to the total NYCA Minimum Unforced Capacity Requirement and (ii) the total of all of the LSE Unforced Capacity Obligations for the NYCA established by the ICAP Spot Market Auction. The LSE Unforced Capacity Obligation will be determined in each Obligation Procurement Period by the ICAP Spot Market Auction, in accordance with the ISO Procedures. Each LSE will be responsible for acquiring sufficient Unforced Capacity to satisfy its LSE Unforced Capacity Obligations. LSEs with Load in more than one Locality will have an LSE Unforced Capacity Obligation for each Locality.

Prior to the beginning of each Capability Period, Transmission Owners shall submit the required Load-shifting information to the ISO and to each LSE affected by the Load-shifting, in accordance with the ISO Procedures. In the event that there is a pending dispute regarding a Transmission Owner's forecast, the ISO shall nevertheless establish each LSE's portion of the NYCA Minimum Unforced Capacity Requirement applicable at the beginning of each Capability Period in accordance with the schedule established in the ISO Procedures, subject to possible

adjustments that may be required as a result of resolution of the dispute through the Expedited Dispute Resolution Procedures set forth in Section 5.17 of this Tariff.

Each month, as Transmission Owners report customers gained and lost by LSEs through Load-shifting, the ISO will adjust each LSE's portion of the NYCA Minimum Unforced Capacity Requirement such that (i) the total Transmission District Installed Capacity requirement remains constant and (ii) an individual LSE's allocated portion reflects the gains and losses. If an LSE loses a customer as a result of that customer leaving the Transmission District, the Load-losing LSE shall be relieved of its obligation to procure Unforced Capacity to cover the Load associated with the departing customer as of the date that the customer's departure is accepted by the ISO and shall be free to sell any excess Unforced Capacity. In addition, when a customer leaves the Transmission District, the ISO will adjust each LSE's portion of the NYCA Minimum Unforced Capacity Requirement so that the total Transmission District's share of the NYCA Minimum Unforced Capacity Requirement remains constant.

5.11.2 LSE Obligations

Each LSE must procure Unforced Capacity in an amount equal to its LSE Unforced Capacity Obligation from any Installed Capacity Supplier through Bilateral Transactions with purchases in ISO-administered Installed Capacity auctions, by self-supply from qualified sources, or by a combination of these methods. Each LSE must certify the amount of Unforced Capacity it has or has obtained prior to the beginning of each Obligation Procurement Period by submitting completed Installed Capacity certification forms to the ISO by the date specified in the ISO Procedures. The Installed Capacity certification forms submitted by the LSEs shall be in the format and include all the information prescribed by the ISO Procedures.

All LSEs shall participate in the ICAP Spot Market Auction pursuant to Section 5.14.1 of this Tariff.

5.11.3 Load-Shifting Adjustments

The ISO shall account for Load-shifting among LSEs each month using the best available information provided to it and the affected LSEs by the individual Transmission Owners**.** The ISO shall, upon notice of Load-shifting by a Transmission Owner and verification by the relevant Load-losing LSE, increase the Load-gaining LSE's LSE Unforced Capacity Obligation, as applicable, and decrease the Load-losing LSE's LSE Unforced Capacity Obligation, as applicable, to reflect the Load-shifting.

The Load-gaining LSE shall pay the Load-losing LSE an amount, pro-rated on a daily basis, based on the Market-Clearing Price of Unforced Capacity determined in the most recent previous applicable ICAP Spot Market Auction until the first day of the month after the nearest following Monthly Installed Capacity Auction is held. The amount paid by a Load-gaining LSE shall reflect any portion of the Load-losing LSE's LSE Unforced Capacity Obligation that is attributable to the shifting Load for the applicable Obligation Procurement Period, in accordance with the ISO Procedures. In addition, the amount paid by a Load-gaining LSE shall be reduced by the Load-losing LSE's share of any rebate associated with the lost Load paid pursuant to Section 5.15 of this Tariff.

Each Transmission Owner shall report to the ISO and to each LSE serving Load in its Transmission District the updated, aggregated LSE Loads with documentation in accordance with and by the date set forth in the ISO Procedures. The ISO shall reallocate a portion of the NYCA Minimum Unforced Capacity Requirement and the Locational Minimum Unforced Capacity Requirement, as applicable, to each LSE for the following Obligation Procurement

Period, which shall reflect all documented Load-shifts as of the end of the current Obligation Procurement Period. Any disputes among Market Participants concerning Load-shifting shall be resolved through the Expedited Dispute Resolution Procedures set forth in Section 5.17 of this Tariff, or the Transmission Owner's retail access procedures, as applicable. In the event of a pending dispute concerning a Load-shift, the ISO shall make its Obligation Procurement Period Installed Capacity adjustments as if the Load-shift reported by the Transmission Owners had occurred, or if the dispute pertains to the timing of a Load-shift, as if the Load-shift occurred on the effective date reported by the Transmission Owner, but will retroactively modify these allocations, as necessary, based on determinations made pursuant to the Expedited Dispute Resolution Procedures set forth in Section 5.17 of this Tariff, or the Transmission Owner's retail access procedures, as applicable.

5.11.4 LSE Locational Minimum Installed Capacity Requirements

The ISO will determine the Locational Minimum Installed Capacity Requirements, stated as a percentage of the Locality's forecasted Capability Year peak Load and expressed in Unforced Capacity terms, that shall be uniformly applicable to each LSE serving Load within a Locality.

In establishing Locational Minimum Installed Capacity Requirements, the ISO will take into account all relevant considerations, including the total NYCA Minimum Installed Capacity Requirement, the NYS Power System transmission Interface Transfer Capability, the election by the holder of rights to UDRs that can provide Capacity from an External Control Area with a capability year start date that is different than the corresponding ISO Capability Year start date ("dissimilar capability year"), the Reliability Rules and any other FERC-approved Locational Minimum Installed Capacity Requirements.

The ISO shall compute the Locational Minimum Installed Capacity Requirements in accordance with ISO Procedures:

(a) to minimize the total cost of capacity at the prescribed level of excess. For purposes of this computation, the ISO shall use the prescribed level of excess (as such term is defined in Section 5.14.1.2.2 of this Tariff,)~~,~~ and shall take into account the cost curves established with the results of net Energy and Ancillary Services revenue offset (as such term is defined in Section 5.14.1.2.2 of this Tariff,)~~,~~ that are (i) if for the first Capability Year covered by the applicable periodic review (as described in Section 5.14.1.2.2 of this Tariff,)~~,~~ the values utilized by the ISO in calculating the reference points for each ICAP Demand Curve as proposed by the ISO to be applicable for such first year in the ISO's filing referenced in Section 5.14.1.2.2.4.11 of this Tariff; and (ii) if for any subsequent Capability Year covered by such periodic review, the values utilized by the ISO in calculating the reference points for each ICAP Demand Curve for the respective Capability Year.

(b) to maintain the loss of load expectation of no more than 0.1 days per year; and

(c) so that the transmission security limits determined by the ISO in accordance with this paragraph and ISO Procedures, are respected. The ISO will make such determination using inputs applicable to the Capability Year to which the Locational Minimum Installed Capacity Requirements will apply. The ISO will compute such limits by determining the bulk power system transmission capability into the Locality, the MW of generation within the Locality accounting for capacity unavailability and changes in generation, the minimum MW of available capacity required for each Locality based on forecasted Load, and using ~~analyzing~~ the N-1-1 system planning criteria ~~and methodology~~ to analyze ~~system component failure~~ thermal limits affecting the Locality. The ISO will post on its web site a report of its determination.

In computing the Locational Minimum Installed Capacity Requirements, the ISO shall utilize results from probabilistic modeling of reliability simulations, recognizing system constraints.

The Installed Capacity Supplier holding rights to UDRs from an External Control Area with a dissimilar capability year shall have one opportunity for a Capability Year in which the Scheduled Line will first be used to offer Capacity associated with the UDRs, to elect that the ISO determine Locational Minimum Installed Capacity Requirements without a quantity of MW from the UDRs for the first month in the Capability Year, and with the same quantity of MW as Unforced Capacity for the remaining months, in each case (a) consistent with and as demonstrated by a contractual arrangement to utilize the UDRs to import the quantity of MW of Capacity into a Locality, and (b) in accordance with ISO Procedures (a “capability year adjustment election”). If there is more than one Installed Capacity Supplier holding rights to UDRs concurrently, an Installed Capacity Supplier’s election pursuant to the preceding sentence (x) shall be binding on the entity to which the NYISO granted the UDRs up to the quantity of MW to which the Installed Capacity Supplier holds rights, and a subsequent assignment of these UDRs to another rights holder will not create the option for another one-time election by the new UDR rights holder, and (y) shall not affect the right another Installed Capacity Supplier may have to make an election. The right to make an election shall remain unless and until an election has been made by one or more holders of rights to the total quantity of MW corresponding to the

UDRs. Absent this one-time election, the UDRs shall be modeled consistently for all months in each Capability Year as elected by the UDR rights holder in its notification to the ISO in accordance with ISO Procedures. Upon such an election, the ISO shall determine the Locational Minimum Unforced Capacity Requirement (i) for the first month of the Capability Year without the quantity of MW of Capacity associated with the UDRs, and (ii) for the remaining eleven months as Unforced Capacity. After the Installed Capacity Supplier has made its one-time election for a quantity of MW, the quantity of MW associated with the UDRs held by the Installed Capacity Supplier shall be modeled consistently for all months in any future Capability Period.

5.11.5 The Locational Minimum Unforced Capacity Requirement

The Locational Minimum Unforced Capacity Requirement represents a minimum level of Unforced Capacity that must be secured by LSEs in each Locality in which it has Load for each Obligation Procurement Period. The Locational Minimum Unforced Capacity Requirement for each Locality shall equal the product of the Locational Minimum Installed Capacity Requirement for a given Locality ((A) with or without the UDRs if there is a capability year adjustment election by a rights holder and (B) without the Locality Exchange MW) and the ratio of (1) the total amount of Unforced Capacity that the specified Resources are qualified to provide (with or without the UDRs associated with dissimilar capability periods, as so elected by the rights holder) during each month in the Capability Period, as of the time the Locational Minimum Unforced Capacity Requirement is determined as specified in ISO Procedures, to (2) the sum of the DMNCs used to determine the Unforced Capacities of such Resources for such Capability Period (with or without the DMNCs associated with the UDRs, as so elected by the rights holder).

The foregoing calculation shall be determined using the Resources in the given Locality in the most recent final version of the ISO's annual Load and Capacity Data Report, with the addition of Resources commencing commercial operation since completion of that report and the deletion of Resources with scheduled or planned retirement dates before or during such Capability Period. The ISO will apply the Locality Exchange Factor for the applicable External Control Area to the MW of Locational Export Capacity that are the lesser of (i) the lesser of the Generator's CRIS and its most recent DMNC, and (ii) the MW pursuant to the notice provided pursuant to Section 5.9.2.2.1 of this Services Tariff.

Under the provisions of this Services Tariff and the ISO Procedures, each LSE will be obligated to procure its LSE Unforced Capacity Obligation. The LSE Unforced Capacity Obligation will be determined for each Obligation Procurement Period by the ICAP Spot Market Auction, in accordance with the ISO Procedures.

Qualified Resources will have the opportunity to supply amounts of Unforced Capacity to meet the LSE Unforced Capacity Obligation as established by the ICAP Spot Market Auction.

To be counted towards the locational component of the LSE Unforced Capacity Obligation, Unforced Capacity owned by the holder of UDRs or contractually combined with UDRs must be deliverable to the NYCA interface with the UDR transmission facility pursuant to NYISO requirements and consistent with the election of the holder of the rights to the UDRs set forth in this Section.

[***NYISO note: Proposed deletion of the following paragraph because it is obsolete. The MW of generators and UDR projects subject to a BSM Offer Floor, or of a generator that is an Interim Service Provider or RMR generator, are only allowed to offer into the ICAP Spot Market Auction.]***

~~In addition, any Customer that purchases Unforced Capacity associated with any generation that is subject to capacity market mitigation measures in an ISO-administered auction may not resell that Unforced Capacity in a subsequent auction at a price greater than the annual mitigated price cap, as applied in accordance with the ISO Procedures in accordance with Sections 5.13.2, 5.13.3, and 5.14.1 of this Tariff. The ISO shall inform Customers that purchase Unforced Capacity in an ISO-administered auction of the amount of Unforced Capacity they have purchased that is subject to capacity market mitigation measures.~~

The ISO shall have the right to audit all executed Installed Capacity contracts and related documentation of arrangements by an LSE to use its own generation to meet its Locational Minimum Installed Capacity Requirement for an upcoming Obligation Procurement Period.

5.11.~~4~~6~~.1~~ Determination of Locality Exchange Factor~~:~~

No later than January 31 each year, the ISO shall determine the Locality Exchange Factor for each Import Constrained Locality relative to each neighboring Control Area.

The ISO shall make each such determination by performing a power flow based analysis according to applicable transmission system planning practices for the determination of interface transfer limits used for the resource adequacy topology. Base case data from the most recent reliability planning process will be incorporated. The Locality Exchange Factor is the ratio of the shift factor on the applicable NYCA interface of a transfer from the Import Constrained Locality to the respective neighboring Control Area, to the shift factor of a transfer from Rest of State to the Import Constrained Locality, calculated in accordance with ISO Procedures. Only the AC circuits comprising the respective neighboring Control Area's interface with the NYCA will participate in the shift. The ISO shall post its Locality Exchange Factors on its website prior to the opening of the Summer Capability Period Auction, and notify the New York State Reliability Council.

Exhibit 34

5.11 Requirements Applicable to LSEs

5.11.1 Allocation of the NYCA Minimum Unforced Capacity Requirement

Each Transmission Owner and each municipal electric utility will submit to the ISO, for its review pursuant to mutually agreed upon procedures which shall be described in the ISO Procedures, the weather-adjusted Load within its Transmission District during the hour in which actual Load in the NYCA was highest (the "NYCA peak Load") for the current Capability Year. (Municipal electric utilities may elect not to submit weather-adjusted data, in which case, weather adjustments shall be performed per ISO procedures. The ISO shall use these data to determine the Adjusted Actual Load at the time of the NYCA peak Load for each Transmission District and municipal electric utility pursuant to ISO Procedures, which shall ensure that transmission losses and the effects of demand reduction programs and the other elements of Adjusted Actual Load are treated in a consistent manner and that all weather normalization procedures meet a minimum criterion described in the ISO Procedures. Each Transmission District or municipal electric utility Load forecast coincident with the NYCA peak shall be the product of that Transmission District or municipal electric utility's Adjusted Actual Load at the time of the NYCA peak Load multiplied by one plus the regional Load growth factor for that Transmission District or municipal electric utility developed pursuant to Section 5.10 of this Tariff. After calculating each Transmission District or municipal electric utility Load forecast, if the ISO determines that an Adjusted Actual Load determined for a Transmission District or municipal electric utility does not reflect reasonable expectations of what Load might reasonably have been expected to occur in that Transmission District or area served by that municipal electric utility in that Capability Year, after taking into consideration the adjustments to account for weather normalization, transmission losses and demand response programs and other

elements of Adjusted Actual Load that are described in the ISO Procedures, the ISO Procedures shall also authorize the ISO to substitute its own measures of Adjusted Actual Load for that Transmission District or area serviced by that municipal electric utility in this calculation, subject to the outcome of dispute resolution procedures if invoked. The ISO's measure of Adjusted Actual Load shall be binding unless otherwise determined as the result of dispute resolution procedures that may be invoked. Each Transmission Owner must also submit aggregate Adjusted Load data, coincident with the NYCA peak hour, for all customers served by each LSE active within its Transmission District. The aggregate Load data may be derived from direct meters or Load profiles of the customers served. Each Transmission Owner shall be required to submit such forecasts and aggregate peak Load data in accordance with the ISO Procedures. Each municipal electric utility may choose to submit its peak Load forecast based on the Transmission District's peak Load forecast provided by a Transmission Owner or to provide its own. Any disputes arising out of the submittals required in this paragraph shall be resolved through the Expedited Dispute Resolution Procedures set forth in Section 5.17 of this Tariff.

All aggregate Load data submitted by a Transmission Owner must be accompanied by documentation indicating that each affected LSE has been provided the data regarding the assignment of customers to the affected LSE. Any disputes between LSEs and Transmission Owners regarding such data or assignments shall be resolved through the Expedited Dispute Resolution Procedures set forth in Section 5.17 of this Tariff, or the Transmission Owner's retail access procedures, as applicable.

The ISO shall allocate the NYCA Minimum Unforced Capacity Requirement among all LSEs serving Load in the NYCA prior to the beginning of each Capability Year. It shall then adjust the NYCA Minimum Unforced Capacity Requirement and reallocate it among LSEs

before each Winter Capability Period as necessary to reflect changes in the factors used to translate ICAP requirements into Unforced Capacity requirements. Each LSE's share of the NYCA Minimum Unforced Capacity Requirement will equal the product of: (i) the NYCA Minimum Installed Capacity Requirement as translated into a NYCA Minimum Unforced Capacity Requirement; and (ii) the ratio of the sum of the Load forecasts coincident with the NYCA peak Load for that LSE's customers in each Transmission District to the NYCA peak Load forecast.

Each LSE Unforced Capacity Obligation will equal the product of (i) the ratio of that LSE's share of the NYCA Minimum Unforced Capacity Requirement to the total NYCA Minimum Unforced Capacity Requirement and (ii) the total of all of the LSE Unforced Capacity Obligations for the NYCA established by the ICAP Spot Market Auction. The LSE Unforced Capacity Obligation will be determined in each Obligation Procurement Period by the ICAP Spot Market Auction, in accordance with the ISO Procedures. Each LSE will be responsible for acquiring sufficient Unforced Capacity to satisfy its LSE Unforced Capacity Obligations. LSEs with Load in more than one Locality will have an LSE Unforced Capacity Obligation for each Locality.

Prior to the beginning of each Capability Period, Transmission Owners shall submit the required Load-shifting information to the ISO and to each LSE affected by the Load-shifting, in accordance with the ISO Procedures. In the event that there is a pending dispute regarding a Transmission Owner's forecast, the ISO shall nevertheless establish each LSE's portion of the NYCA Minimum Unforced Capacity Requirement applicable at the beginning of each Capability Period in accordance with the schedule established in the ISO Procedures, subject to possible

adjustments that may be required as a result of resolution of the dispute through the Expedited Dispute Resolution Procedures set forth in Section 5.17 of this Tariff.

Each month, as Transmission Owners report customers gained and lost by LSEs through Load-shifting, the ISO will adjust each LSE's portion of the NYCA Minimum Unforced Capacity Requirement such that (i) the total Transmission District Installed Capacity requirement remains constant and (ii) an individual LSE's allocated portion reflects the gains and losses. If an LSE loses a customer as a result of that customer leaving the Transmission District, the Load-losing LSE shall be relieved of its obligation to procure Unforced Capacity to cover the Load associated with the departing customer as of the date that the customer's departure is accepted by the ISO and shall be free to sell any excess Unforced Capacity. In addition, when a customer leaves the Transmission District, the ISO will adjust each LSE's portion of the NYCA Minimum Unforced Capacity Requirement so that the total Transmission District's share of the NYCA Minimum Unforced Capacity Requirement remains constant.

5.11.2 LSE Obligations

Each LSE must procure Unforced Capacity in an amount equal to its LSE Unforced Capacity Obligation from any Installed Capacity Supplier through Bilateral Transactions with purchases in ISO-administered Installed Capacity auctions, by self-supply from qualified sources, or by a combination of these methods. Each LSE must certify the amount of Unforced Capacity it has or has obtained prior to the beginning of each Obligation Procurement Period by submitting completed Installed Capacity certification forms to the ISO by the date specified in the ISO Procedures. The Installed Capacity certification forms submitted by the LSEs shall be in the format and include all the information prescribed by the ISO Procedures.

All LSEs shall participate in the ICAP Spot Market Auction pursuant to Section 5.14.1 of this Tariff.

5.11.3 Load-Shifting Adjustments

The ISO shall account for Load-shifting among LSEs each month using the best available information provided to it and the affected LSEs by the individual Transmission Owners**.** The ISO shall, upon notice of Load-shifting by a Transmission Owner and verification by the relevant Load-losing LSE, increase the Load-gaining LSE's LSE Unforced Capacity Obligation, as applicable, and decrease the Load-losing LSE's LSE Unforced Capacity Obligation, as applicable, to reflect the Load-shifting.

The Load-gaining LSE shall pay the Load-losing LSE an amount, pro-rated on a daily basis, based on the Market-Clearing Price of Unforced Capacity determined in the most recent previous applicable ICAP Spot Market Auction until the first day of the month after the nearest following Monthly Installed Capacity Auction is held. The amount paid by a Load-gaining LSE shall reflect any portion of the Load-losing LSE's LSE Unforced Capacity Obligation that is attributable to the shifting Load for the applicable Obligation Procurement Period, in accordance with the ISO Procedures. In addition, the amount paid by a Load-gaining LSE shall be reduced by the Load-losing LSE's share of any rebate associated with the lost Load paid pursuant to Section 5.15 of this Tariff.

Each Transmission Owner shall report to the ISO and to each LSE serving Load in its Transmission District the updated, aggregated LSE Loads with documentation in accordance with and by the date set forth in the ISO Procedures. The ISO shall reallocate a portion of the NYCA Minimum Unforced Capacity Requirement and the Locational Minimum Unforced Capacity Requirement, as applicable, to each LSE for the following Obligation Procurement

Period, which shall reflect all documented Load-shifts as of the end of the current Obligation Procurement Period. Any disputes among Market Participants concerning Load-shifting shall be resolved through the Expedited Dispute Resolution Procedures set forth in Section 5.17 of this Tariff, or the Transmission Owner's retail access procedures, as applicable. In the event of a pending dispute concerning a Load-shift, the ISO shall make its Obligation Procurement Period Installed Capacity adjustments as if the Load-shift reported by the Transmission Owners had occurred, or if the dispute pertains to the timing of a Load-shift, as if the Load-shift occurred on the effective date reported by the Transmission Owner, but will retroactively modify these allocations, as necessary, based on determinations made pursuant to the Expedited Dispute Resolution Procedures set forth in Section 5.17 of this Tariff, or the Transmission Owner's retail access procedures, as applicable.

5.11.4 LSE Locational Minimum Installed Capacity Requirements

The ISO will determine the Locational Minimum Installed Capacity Requirements, stated as a percentage of the Locality's forecasted Capability Year peak Load and expressed in Unforced Capacity terms, that shall be uniformly applicable to each LSE serving Load within a Locality.

In establishing Locational Minimum Installed Capacity Requirements, the ISO will take into account all relevant considerations, including the total NYCA Minimum Installed Capacity Requirement, the NYS Power System transmission Interface Transfer Capability, the election by the holder of rights to UDRs that can provide Capacity from an External Control Area with a capability year start date that is different than the corresponding ISO Capability Year start date ("dissimilar capability year"), the Reliability Rules and any other FERC-approved Locational Minimum Installed Capacity Requirements.

The ISO shall compute the Locational Minimum Installed Capacity Requirements in accordance with ISO Procedures:

(a) to minimize the total cost of capacity at the prescribed level of excess. For purposes of this computation, the ISO shall use the prescribed level of excess (as such term is defined in Section 5.14.1.2.2 of this Tariff,) and shall take into account the cost curves established with the results of net Energy and Ancillary Services revenue offset (as such term is defined in Section 5.14.1.2.2 of this Tariff,) that are (i) if for the first Capability Year covered by the applicable periodic review (as described in Section 5.14.1.2.2 of this Tariff,) the values utilized by the ISO in calculating the reference points for each ICAP Demand Curve as proposed by the ISO to be applicable for such first year in the ISO's filing referenced in Section 5.14.1.2.2.4.11 of this Tariff; and (ii) if for any subsequent Capability Year covered by such periodic review, the values utilized by the ISO in calculating the reference points for each ICAP Demand Curve for the respective Capability Year.

(b) to maintain the loss of load expectation of no more than 0.1 days per year; and

(c) so that the transmission security limits determined by the ISO in accordance with this paragraph and ISO Procedures, are respected. The ISO will make such determination using inputs applicable to the Capability Year to which the Locational Minimum Installed Capacity Requirements will apply. The ISO will compute such limits by determining the bulk power system transmission capability into the Locality, the MW of generation within the Locality accounting for capacity unavailability and changes in generation, the minimum MW of available capacity required for each Locality based on forecasted Load, and using the N-1-1 system planning criteria to analyze thermal limits affecting the Locality. The ISO will post on its web site a report of its determination.

In computing the Locational Minimum Installed Capacity Requirements, the ISO shall utilize results from probabilistic modeling of reliability simulations, recognizing system constraints.

The Installed Capacity Supplier holding rights to UDRs from an External Control Area with a dissimilar capability year shall have one opportunity for a Capability Year in which the Scheduled Line will first be used to offer Capacity associated with the UDRs, to elect that the ISO determine Locational Minimum Installed Capacity Requirements without a quantity of MW from the UDRs for the first month in the Capability Year, and with the same quantity of MW as Unforced Capacity for the remaining months, in each case (a) consistent with and as demonstrated by a contractual arrangement to utilize the UDRs to import the quantity of MW of Capacity into a Locality, and (b) in accordance with ISO Procedures (a "capability year adjustment election"). If there is more than one Installed Capacity Supplier holding rights to UDRs concurrently, an Installed Capacity Supplier's election pursuant to the preceding sentence (x) shall be binding on the entity to which the NYISO granted the UDRs up to the quantity of MW to which the Installed Capacity Supplier holds rights, and a subsequent assignment of these UDRs to another rights holder will not create the option for another one-time election by the new UDR rights holder, and (y) shall not affect the right another Installed Capacity Supplier may have to make an election. The right to make an election shall remain unless and until an election has been made by one or more holders of rights to the total quantity of MW corresponding to the UDRs. Absent this one-time election, the UDRs shall be modeled consistently for all months in each Capability Year as elected by the UDR rights holder in its notification to the ISO in accordance with ISO Procedures. Upon such an election, the ISO shall determine the Locational Minimum Unforced Capacity Requirement (i) for the first month of the Capability Year without the quantity of MW of Capacity associated with the UDRs, and (ii) for the remaining eleven months as Unforced Capacity. After the Installed Capacity Supplier has made its one-time election for a quantity of MW, the quantity of MW associated with the UDRs held by the Installed Capacity Supplier shall be modeled consistently for all months in any future Capability Period.

5.11.5 The Locational Minimum Unforced Capacity Requirement

The Locational Minimum Unforced Capacity Requirement represents a minimum level of Unforced Capacity that must be secured by LSEs in each Locality in which it has Load for each Obligation Procurement Period. The Locational Minimum Unforced Capacity Requirement for each Locality shall equal the product of the Locational Minimum Installed Capacity Requirement for a given Locality ((A) with or without the UDRs if there is a capability year adjustment election by a rights holder and (B) without the Locality Exchange MW) and the ratio of (1) the total amount of Unforced Capacity that the specified Resources are qualified to provide (with or without the UDRs associated with dissimilar capability periods, as so elected by the rights holder) during each month in the Capability Period, as of the time the Locational Minimum Unforced Capacity Requirement is determined as specified in ISO Procedures, to (2) the sum of the DMNCs used to determine the Unforced Capacities of such Resources for such Capability Period (with or without the DMNCs associated with the UDRs, as so elected by the rights holder).

The foregoing calculation shall be determined using the Resources in the given Locality in the most recent final version of the ISO's annual Load and Capacity Data Report, with the addition of Resources commencing commercial operation since completion of that report and the deletion of Resources with scheduled or planned retirement dates before or during such Capability Period. The ISO will apply the Locality Exchange Factor for the applicable External Control Area to the MW of Locational Export Capacity that are the lesser of (i) the lesser of the Generator's CRIS and its most recent DMNC, and (ii) the MW pursuant to the notice provided pursuant to Section 5.9.2.2.1 of this Services Tariff.

Under the provisions of this Services Tariff and the ISO Procedures, each LSE will be obligated to procure its LSE Unforced Capacity Obligation. The LSE Unforced Capacity Obligation will be determined for each Obligation Procurement Period by the ICAP Spot Market Auction, in accordance with the ISO Procedures.

Qualified Resources will have the opportunity to supply amounts of Unforced Capacity to meet the LSE Unforced Capacity Obligation as established by the ICAP Spot Market Auction.

To be counted towards the locational component of the LSE Unforced Capacity Obligation, Unforced Capacity owned by the holder of UDRs or contractually combined with UDRs must be deliverable to the NYCA interface with the UDR transmission facility pursuant to NYISO requirements and consistent with the election of the holder of the rights to the UDRs set forth in this Section.

[*NYISO note: Proposed deletion of the following paragraph because it is obsolete. The MW of generators and UDR projects subject to a BSM Offer Floor, or of a generator that is an Interim Service Provider or RMR generator, are only allowed to offer into the ICAP Spot Market Auction.]*

~~In addition, any Customer that purchases Unforced Capacity associated with any generation that is subject to capacity market mitigation measures in an ISO-administered auction may not resell that Unforced Capacity in a subsequent auction at a price greater than the annual mitigated price cap, as applied in accordance with the ISO Procedures in accordance with Sections 5.13.2, 5.13.3, and 5.14.1 of this Tariff. The ISO shall inform Customers that purchase Unforced Capacity in an ISO-administered auction of the amount of Unforced Capacity they have purchased that is subject to capacity market mitigation measures.~~

The ISO shall have the right to audit all executed Installed Capacity contracts and related documentation of arrangements by an LSE to use its own generation to meet its Locational Minimum Installed Capacity Requirement for an upcoming Obligation Procurement Period.

5.11.~~4~~6~~.1~~ Determination of Locality Exchange Factor~~:~~

No later than January 31 each year, the ISO shall determine the Locality Exchange Factor for each Import Constrained Locality relative to each neighboring Control Area.

The ISO shall make each such determination by performing a power flow based analysis according to applicable transmission system planning practices for the determination of interface transfer limits used for the resource adequacy topology. Base case data from the most recent reliability planning process will be incorporated. The Locality Exchange Factor is the ratio of the shift factor on the applicable NYCA interface of a transfer from the Import Constrained Locality to the respective neighboring Control Area, to the shift factor of a transfer from Rest of State to the Import Constrained Locality, calculated in accordance with ISO Procedures. Only the AC circuits comprising the respective neighboring Control Area’s interface with the NYCA will participate in the shift. The ISO shall post its Locality Exchange Factors on its website prior to the opening of the Summer Capability Period Auction, and notify the New York State Reliability Council.

Exhibit 35

Alternative Method for Determining LCRs

Zachary Stines
Associate Market Design Specialist

Installed Capacity Working Group

February 6, 2018, NYISO

NEW YORK INDEPENDENT SYSTEM OPERATOR

Agenda

- 2018 Project Plan & Milestones
- 2017 & 2018 Base Cases
- Next Steps
- Questions

2018 Project Plan & Milestones

2018 Project Plan

- **Project Plan:**
  - Seek approval and file tariff revisions with FERC
  - Update documentation, procedures, and processes
  - Internal training
  - Development of production software
  - User acceptance testing of production software
  - Deployment of production software

2018 Required Resources

- **Resources:**
  - GE Energy Consulting
  - ICAP Market Design
  - Resource Adequacy
  - ICAP Market Operations
  - Operations Engineering
  - Legal

2018 Project Milestones

- February 14: Business Issues Committee
- February 28: Management Committee
- March 20: Board of Directors
- March 30: File Section 205 with FERC
- April: Updating documentation, procedures, processes
- June: FERC action
- June 29: Production Version Complete
- July: User Acceptance Testing
- September: Production Deployment

Project Plan & Requested Sensitivities

- GE will be working towards a production version of the optimization tool
  - Parallel projects associated with NYISO computing infrastructure (i.e., transition to cloud computing) increase the complexity of the transfer and required resources
- NYISO staff will be working to update all internal documentation and processes, along with testing of production software
- The implementation deadline for January 2019 LCRs cannot be met if any steps in the project plan and timeline are postponed
- As a result of the strict project timeline and other projects' constraints on resources required for the steps towards implementation, the NYISO is responding in the following slides to some of stakeholders' requests for information but we are unable to conduct and present the additional sensitivities requested at the January 25th ICAPWG

NEW YORK INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY

2017 & 2018 Base Cases

NYSRC Installed Capacity Requirement Reports

- Publically available on the NYSRC website
  - http://www.nysrc.org/NYSRC_NYCA_ICR_Reports.html
- Reports identify changes in topology and assumptions for the study year

2017 & 2018 Base Cases

- Load Forecast Uncertainty
- Interface limits
- EFORd on transmission and UDRs
- Net CONE Curves
- Transmission Security Floors

Load Forecast Uncertainty

- **Load in the model is broken out into 7 bins**
  - Bins are used to simulate different load levels
  - Each bin is associated with a probability of occurring
  - Highest bins (1-3) are main drivers of LOLE

2017 & 2018 Load Forecast Uncertainty

- H & I load forecast uncertainty decreased
- J & K load forecast uncertainty increased
- These would tend to increase southeast NY capacity requirement

	H & I			J			K		
	Bin 1	Bin 2	Bin 3	Bin 1	Bin 2	Bin 3	Bin 1	Bin 2	Bin 3
2017	111.13%	107.46%	102.91%	106.76%	104.75%	101.91%	114.00%	111.23%	108.02%
2018	108.22%	106.39%	102.93%	107.86%	105.47%	102.19%	115.86%	112.06%	106.95%
Δ	-2.91%	-1.07%	0.02%	1.10%	0.72%	0.28%	1.86%	0.83%	-1.07%

NEW YORK INDEPENDENT SYSTEM OPERATOR

EFORd on Cables

- Underground cables
  - Increase in EFORd on Dunwoody South, ConEd LILCO, Y49Y50, Cross Sound Cable
- UDRs
  - Net increase in EFORd on the UDRs
- These would tend to increase southeast NY capacity requirement

Interface Limits

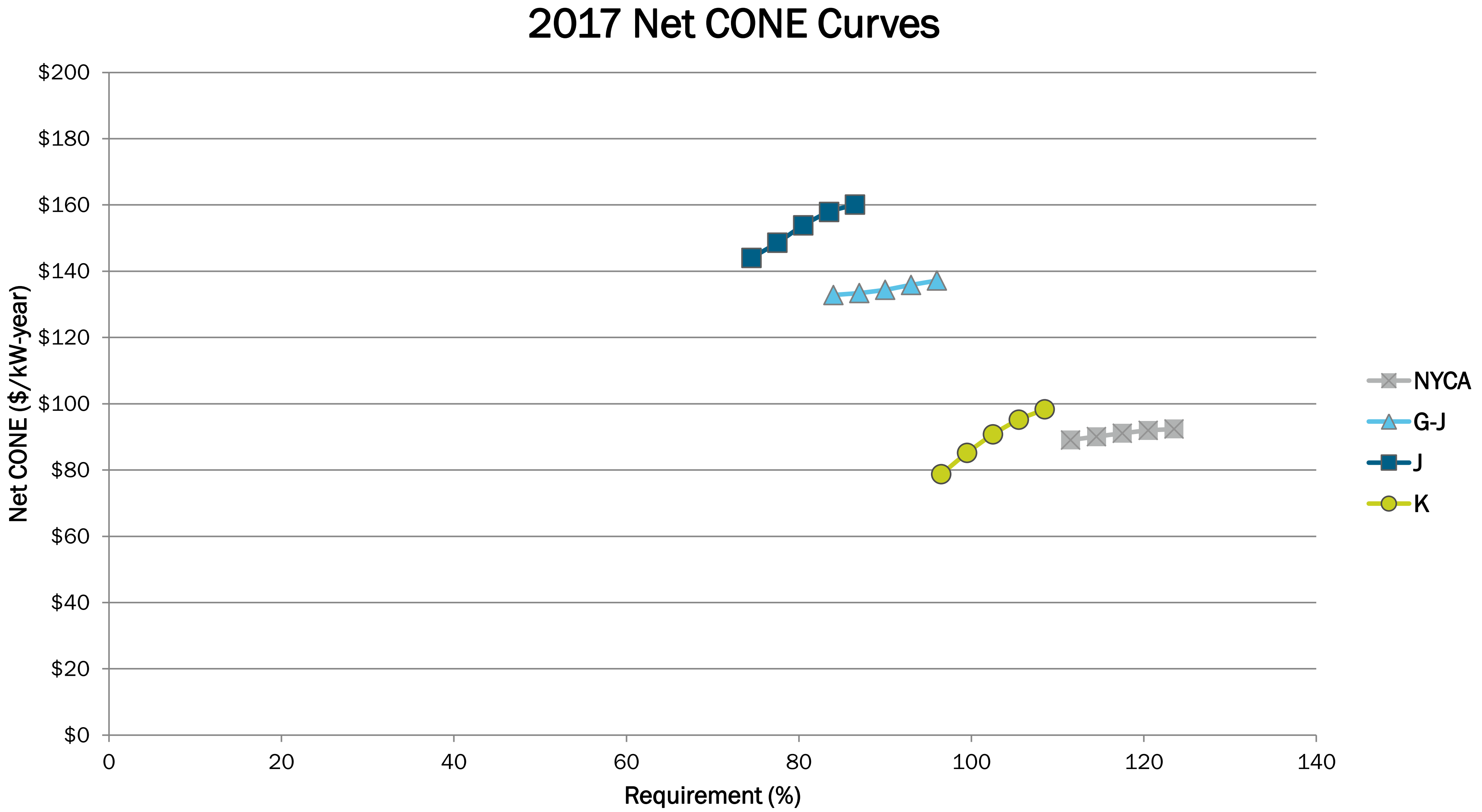
- Topological changes associated with the entry of the CPV
  - More binding effect (or congestion) on UPNY-SENY and Marcy South
  - Increase of UPNY-ConEd and I to J & K
- Northport Norwalk interface decrease
  - 428/369 MW to 404/260 MW
- Long Island Sum interface decrease
  - 120/91/0 MW to 104/74/0 MW
- Long Island West interface decrease
  - 34 MW to 18 MW

NEW YORK INDEPENDENT SYSTEM OPERATOR

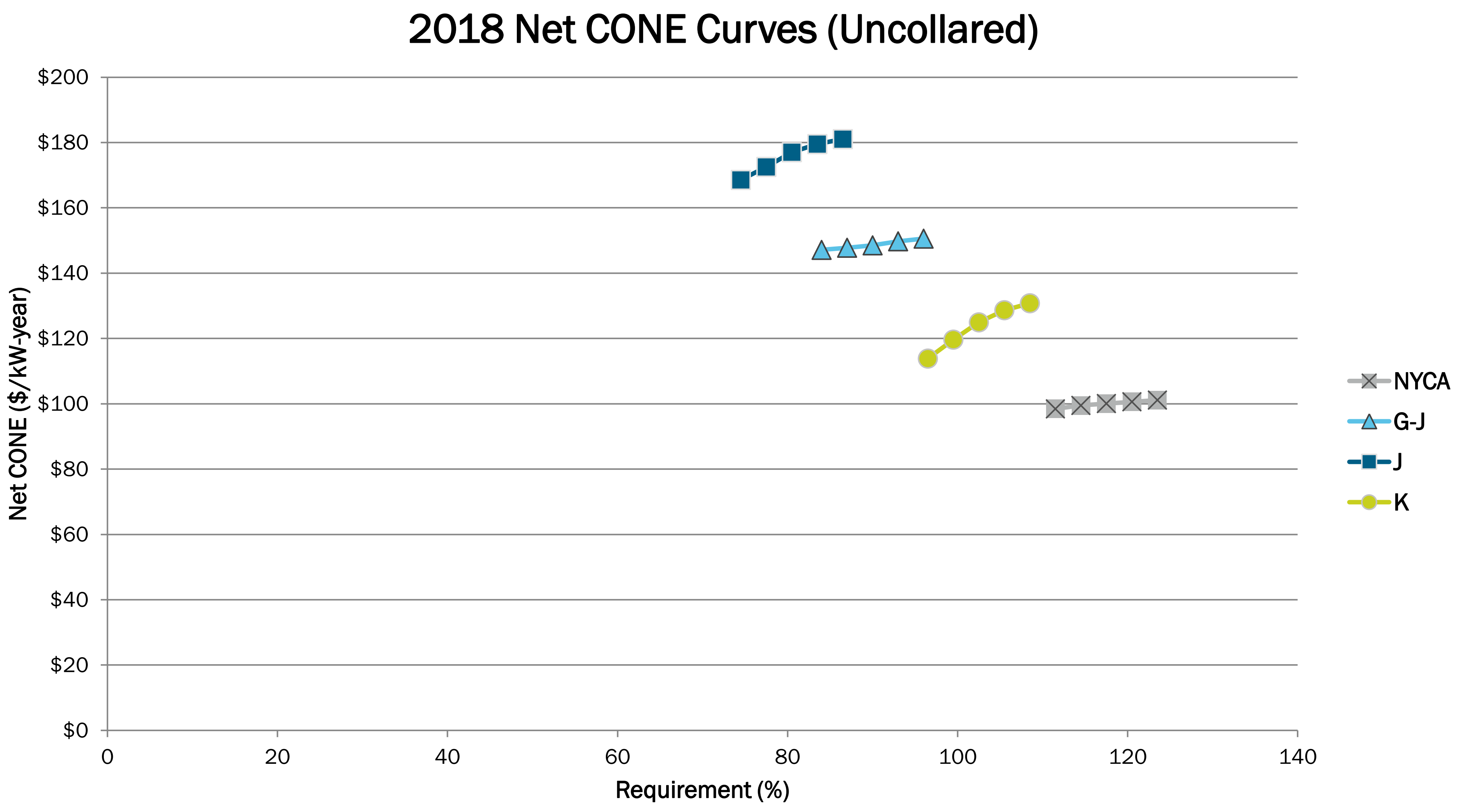
Net CONE Curves

- All net CONE curves increase from 2017 to 2018
- Relative order of the cost of the localities remained the same (i.e., J being the largest net CONE followed by G-J, K, and NYCA)

NEW YORK INDEPENDENT SYSTEM OPERATOR



2017 Net CONE Curves
Net CONE ($/kW-year)
$200
$180
$160
$140
$120
$100
$80
$60
$40
$20
$0
0
20
40
60
80
100
120
140
Requirement (%)
NYCA
G-J
J
K



2018 Net CONE Curves (Uncollared)
Net CONE ($/kW-year)
$200
$180
$160
$140
$120
$100
$80
$60
$40
$20
$0
0
20
40
60
80
100
120
140
Requirement (%)
NYCA
G-J
J
K

2018 Transmission Security Limits

Transmission Security Requirements	G-J	Zone J	Zone K
Load Forecast (MW)	15,890	11,541	5,445
Transmission Security Import Limit (MW)	3,000	3,175	350
Transmission Security UCAP Requirement (MW)	12,890	8,366	5,095
Transmission Security UCAP Requirement (%)	81.1%	72.5%	93.6%
5 Year EFORd (%)	9.55%	9.05%	9.26%
Transmission Security ICAP Requirement (MW)	14,250	9,198	5,615
Transmission Security LCR Floor (%)	**89.7%**	**79.7%**	**103.1%**

NEW YORK INDEPENDENT SYSTEM OPERATOR

Changes from 2017 to 2018

- The changes from the 2017 base case to the 2018 base case required more capacity in southeast New York in order to meet the reliability criteria (i.e., LOLE $\leq$ 0.1 days/year)
  - This is observed in both the current and the optimization methodologies

2017 & 2018 LCRs

	Approved LCRs			Optimized LCRs		
	G-J	J	K	G-J	J	K
2017	91.5%	81.5%	103.5%	90.7%	80.2%	104.2%
2018	94.5%	80.5%	103.5%	90.8%	79.7%	107.5%

2017 & 2018 LCRs (ICAP MW)

	Approved LCRs (MW)			Optimized LCRs (MW)		
	G-J	J	K	G-J	J	K
2017	14,696.1	9,511.1	5,617.0	14,569.8	9,354.7	5,652.5
2018	15,042.5	9,288.9	5,605.6	14,432.0	9,198.2	5,856.1
Δ Locality MW	346.4	-222.2	-11.5	-137.9	-156.5	203.6
Δ Southeast New York MW	334.9			65.7		

- In 2018, both the current and optimized base cases require more capacity in southeast New York

Design Objectives

- The alternative methodology is consistent with the design objective and guiding principles
  - Maintains reliability
  - Transparent
  - Predictive
  - Efficient allocation of capacity

Next Steps

Next Steps

- The NYISO will consider input received during today's ICAP Working Group meeting
- BIC on February 14th
- Additional comments sent to deckels@nyiso.com will be considered

NEW YORK INDEPENDENT SYSTEM OPERATOR

Questions?

The Mission of the New York Independent System Operator, in collaboration with its stakeholders, is to serve the public interest and provide benefits to consumers by:

- Maintaining and enhancing regional reliability
- Operating open, fair and competitive wholesale electricity markets
- Planning the power system for the future
- Providing factual information to policy makers, stakeholders and investors in the power system

www.nyiso.com

NEW YORK INDEPENDENT SYSTEM OPERATOR

Exhibit 36

5.11 Requirements Applicable to LSEs

5.11.1 Allocation of the NYCA Minimum Unforced Capacity Requirement

Each Transmission Owner and each municipal electric utility will submit to the ISO, for its review pursuant to mutually agreed upon procedures which shall be described in the ISO Procedures, the weather-adjusted Load within its Transmission District during the hour in which actual Load in the NYCA was highest (the "NYCA peak Load") for the current Capability Year. (Municipal electric utilities may elect not to submit weather-adjusted data, in which case, weather adjustments shall be performed per ISO procedures. The ISO shall use these data to determine the Adjusted Actual Load at the time of the NYCA peak Load for each Transmission District and municipal electric utility pursuant to ISO Procedures, which shall ensure that transmission losses and the effects of demand reduction programs and the other elements of Adjusted Actual Load are treated in a consistent manner and that all weather normalization procedures meet a minimum criterion described in the ISO Procedures. Each Transmission District or municipal electric utility Load forecast coincident with the NYCA peak shall be the product of that Transmission District or municipal electric utility's Adjusted Actual Load at the time of the NYCA peak Load multiplied by one plus the regional Load growth factor for that Transmission District or municipal electric utility developed pursuant to Section 5.10 of this Tariff. After calculating each Transmission District or municipal electric utility Load forecast, if the ISO determines that an Adjusted Actual Load determined for a Transmission District or municipal electric utility does not reflect reasonable expectations of what Load might reasonably have been expected to occur in that Transmission District or area served by that municipal electric utility in that Capability Year, after taking into consideration the adjustments to account for weather normalization, transmission losses and demand response programs and other

elements of Adjusted Actual Load that are described in the ISO Procedures, the ISO Procedures shall also authorize the ISO to substitute its own measures of Adjusted Actual Load for that Transmission District or area serviced by that municipal electric utility in this calculation, subject to the outcome of dispute resolution procedures if invoked. The ISO's measure of Adjusted Actual Load shall be binding unless otherwise determined as the result of dispute resolution procedures that may be invoked. Each Transmission Owner must also submit aggregate Adjusted Load data, coincident with the NYCA peak hour, for all customers served by each LSE active within its Transmission District. The aggregate Load data may be derived from direct meters or Load profiles of the customers served. Each Transmission Owner shall be required to submit such forecasts and aggregate peak Load data in accordance with the ISO Procedures. Each municipal electric utility may choose to submit its peak Load forecast based on the Transmission District's peak Load forecast provided by a Transmission Owner or to provide its own. Any disputes arising out of the submittals required in this paragraph shall be resolved through the Expedited Dispute Resolution Procedures set forth in Section 5.17 of this Tariff.

All aggregate Load data submitted by a Transmission Owner must be accompanied by documentation indicating that each affected LSE has been provided the data regarding the assignment of customers to the affected LSE. Any disputes between LSEs and Transmission Owners regarding such data or assignments shall be resolved through the Expedited Dispute Resolution Procedures set forth in Section 5.17 of this Tariff, or the Transmission Owner's retail access procedures, as applicable.

The ISO shall allocate the NYCA Minimum Unforced Capacity Requirement among all LSEs serving Load in the NYCA prior to the beginning of each Capability Year. It shall then adjust the NYCA Minimum Unforced Capacity Requirement and reallocate it among LSEs

before each Winter Capability Period as necessary to reflect changes in the factors used to translate ICAP requirements into Unforced Capacity requirements. Each LSE's share of the NYCA Minimum Unforced Capacity Requirement will equal the product of: (i) the NYCA Minimum Installed Capacity Requirement as translated into a NYCA Minimum Unforced Capacity Requirement; and (ii) the ratio of the sum of the Load forecasts coincident with the NYCA peak Load for that LSE's customers in each Transmission District to the NYCA peak Load forecast.

Each LSE Unforced Capacity Obligation will equal the product of (i) the ratio of that LSE's share of the NYCA Minimum Unforced Capacity Requirement to the total NYCA Minimum Unforced Capacity Requirement and (ii) the total of all of the LSE Unforced Capacity Obligations for the NYCA established by the ICAP Spot Market Auction. The LSE Unforced Capacity Obligation will be determined in each Obligation Procurement Period by the ICAP Spot Market Auction, in accordance with the ISO Procedures. Each LSE will be responsible for acquiring sufficient Unforced Capacity to satisfy its LSE Unforced Capacity Obligations. LSEs with Load in more than one Locality will have an LSE Unforced Capacity Obligation for each Locality.

Prior to the beginning of each Capability Period, Transmission Owners shall submit the required Load-shifting information to the ISO and to each LSE affected by the Load-shifting, in accordance with the ISO Procedures. In the event that there is a pending dispute regarding a Transmission Owner's forecast, the ISO shall nevertheless establish each LSE's portion of the NYCA Minimum Unforced Capacity Requirement applicable at the beginning of each Capability Period in accordance with the schedule established in the ISO Procedures, subject to possible

adjustments that may be required as a result of resolution of the dispute through the Expedited Dispute Resolution Procedures set forth in Section 5.17 of this Tariff.

Each month, as Transmission Owners report customers gained and lost by LSEs through Load-shifting, the ISO will adjust each LSE's portion of the NYCA Minimum Unforced Capacity Requirement such that (i) the total Transmission District Installed Capacity requirement remains constant and (ii) an individual LSE's allocated portion reflects the gains and losses. If an LSE loses a customer as a result of that customer leaving the Transmission District, the Load-losing LSE shall be relieved of its obligation to procure Unforced Capacity to cover the Load associated with the departing customer as of the date that the customer's departure is accepted by the ISO and shall be free to sell any excess Unforced Capacity. In addition, when a customer leaves the Transmission District, the ISO will adjust each LSE's portion of the NYCA Minimum Unforced Capacity Requirement so that the total Transmission District's share of the NYCA Minimum Unforced Capacity Requirement remains constant.

5.11.2 LSE Obligations

Each LSE must procure Unforced Capacity in an amount equal to its LSE Unforced Capacity Obligation from any Installed Capacity Supplier through Bilateral Transactions with purchases in ISO-administered Installed Capacity auctions, by self-supply from qualified sources, or by a combination of these methods. Each LSE must certify the amount of Unforced Capacity it has or has obtained prior to the beginning of each Obligation Procurement Period by submitting completed Installed Capacity certification forms to the ISO by the date specified in the ISO Procedures. The Installed Capacity certification forms submitted by the LSEs shall be in the format and include all the information prescribed by the ISO Procedures.

All LSEs shall participate in the ICAP Spot Market Auction pursuant to Section 5.14.1 of this Tariff.

5.11.3 Load-Shifting Adjustments

The ISO shall account for Load-shifting among LSEs each month using the best available information provided to it and the affected LSEs by the individual Transmission Owners. The ISO shall, upon notice of Load-shifting by a Transmission Owner and verification by the relevant Load-losing LSE, increase the Load-gaining LSE's LSE Unforced Capacity Obligation, as applicable, and decrease the Load-losing LSE's LSE Unforced Capacity Obligation, as applicable, to reflect the Load-shifting.

The Load-gaining LSE shall pay the Load-losing LSE an amount, pro-rated on a daily basis, based on the Market-Clearing Price of Unforced Capacity determined in the most recent previous applicable ICAP Spot Market Auction until the first day of the month after the nearest following Monthly Installed Capacity Auction is held. The amount paid by a Load-gaining LSE shall reflect any portion of the Load-losing LSE's LSE Unforced Capacity Obligation that is attributable to the shifting Load for the applicable Obligation Procurement Period, in accordance with the ISO Procedures. In addition, the amount paid by a Load-gaining LSE shall be reduced by the Load-losing LSE's share of any rebate associated with the lost Load paid pursuant to Section 5.15 of this Tariff.

Each Transmission Owner shall report to the ISO and to each LSE serving Load in its Transmission District the updated, aggregated LSE Loads with documentation in accordance with and by the date set forth in the ISO Procedures. The ISO shall reallocate a portion of the NYCA Minimum Unforced Capacity Requirement and the Locational Minimum Unforced Capacity Requirement, as applicable, to each LSE for the following Obligation Procurement

Period, which shall reflect all documented Load-shifts as of the end of the current Obligation Procurement Period. Any disputes among Market Participants concerning Load-shifting shall be resolved through the Expedited Dispute Resolution Procedures set forth in Section 5.17 of this Tariff, or the Transmission Owner's retail access procedures, as applicable. In the event of a pending dispute concerning a Load-shift, the ISO shall make its Obligation Procurement Period Installed Capacity adjustments as if the Load-shift reported by the Transmission Owners had occurred, or if the dispute pertains to the timing of a Load-shift, as if the Load-shift occurred on the effective date reported by the Transmission Owner, but will retroactively modify these allocations, as necessary, based on determinations made pursuant to the Expedited Dispute Resolution Procedures set forth in Section 5.17 of this Tariff, or the Transmission Owner's retail access procedures, as applicable.

5.11.4 LSE Locational Minimum Installed Capacity Requirements

The ISO will determine the Locational Minimum Installed Capacity Requirements, stated as a percentage of the Locality's forecasted Capability Year peak Load and expressed in Unforced Capacity terms, that shall be uniformly applicable to each LSE serving Load within a Locality.

In establishing Locational Minimum Installed Capacity Requirements, the ISO will take into account all relevant considerations, including the total NYCA Minimum Installed Capacity Requirement, the NYS Power System transmission Interface Transfer Capability, the election by the holder of rights to UDRs that can provide Capacity from an External Control Area with a capability year start date that is different than the corresponding ISO Capability Year start date ("dissimilar capability year"), the Reliability Rules and any other FERC-approved Locational Minimum Installed Capacity Requirements.

The ISO shall compute the Locational Minimum Installed Capacity Requirements in accordance with ISO Procedures:

(a) to minimize the total cost of capacity at the prescribed level of excess. For purposes of this computation, the ISO shall use the prescribed level of excess (as such term is defined in Section 5.14.1.2.2 of this Tariff,) and shall take into account the cost curves established with the results of net Energy and Ancillary Services revenue offset (as such term is defined in Section 5.14.1.2.2 of this Tariff,) that are (i) if for the first Capability Year covered by the applicable periodic review (as described in Section 5.14.1.2.2 of this Tariff,) the values utilized by the ISO in calculating the reference points for each ICAP Demand Curve as proposed by the ISO to be applicable for such first year in the ISO's filing referenced in Section 5.14.1.2.2.4.11 of this Tariff; and (ii) if for any subsequent Capability Year covered by such periodic review, the values utilized by the ISO in calculating the reference points for each ICAP Demand Curve for the respective Capability Year.

(b) to maintain the loss of load expectation of no more than 0.1 days per year; and

(c) so that the transmission security limits determined by the ISO in accordance with this paragraph and ISO Procedures, are respected. The ISO will determine these limits using inputs consistent with the NYSRC Installed Reserve Margin base case for~~applicable to~~ the Capability Year to which the Locational Minimum Installed Capacity Requirements will apply. The ISO will compute such limits by determining the bulk power system transmission capability into the Locality, the MW of generation within the Locality accounting for capacity unavailability, the minimum MW of available capacity required for each Locality based on forecasted Load, and using the N-1-1 ~~(*i.e.*, a sequence of a primary contingency event followed by a secondary contingency event)~~ system planning criteria (*i.e.*, a sequence of a primary contingency event followed by a secondary contingency event) to analyze thermal limits affecting the Locality. The ISO will post on its web site a report of its determination.

In computing the Locational Minimum Installed Capacity Requirements, the ISO shall utilize results from probabilistic modeling of reliability simulations, recognizing system constraints.

The Installed Capacity Supplier holding rights to UDRs from an External Control Area with a dissimilar capability year shall have one opportunity for a Capability Year in which the Scheduled Line will first be used to offer Capacity associated with the UDRs, to elect that the ISO determine Locational Minimum Installed Capacity Requirements without a quantity of MW from the UDRs for the first month in the Capability Year, and with the same quantity of MW as Unforced Capacity for the remaining months, in each case (a) consistent with and as demonstrated by a contractual arrangement to utilize the UDRs to import the quantity of MW of Capacity into a Locality, and (b) in accordance with ISO Procedures (a "capability year adjustment election"). If there is more than one Installed Capacity Supplier holding rights to UDRs concurrently, an Installed Capacity Supplier's election pursuant to the preceding sentence (x) shall be binding on the entity to which the NYISO granted the UDRs up to the quantity of MW to which the Installed Capacity Supplier holds rights, and a subsequent assignment of these UDRs to another rights holder will not create the option for another one-time election by the new UDR rights holder, and (y) shall not affect the right another Installed Capacity Supplier may have to make an election. The right to make an election shall remain unless and until an election has been made by one or more holders of rights to the total quantity of MW corresponding to the UDRs. Absent this one-time election, the UDRs shall be modeled consistently for all months in each Capability Year as elected by the UDR rights holder in its notification to the ISO in accordance with ISO Procedures. Upon such an election, the ISO shall determine the Locational Minimum Unforced Capacity Requirement (i) for the first month of the Capability Year without the quantity of MW of Capacity associated with the UDRs, and (ii) for the remaining eleven months as Unforced Capacity. After the Installed Capacity Supplier has made its one-time election for a quantity of MW, the quantity of MW associated with the UDRs held by the Installed Capacity Supplier shall be modeled consistently for all months in any future Capability Period.

5.11.5 The Locational Minimum Unforced Capacity Requirement

The Locational Minimum Unforced Capacity Requirement represents a minimum level of Unforced Capacity that must be secured by LSEs in each Locality in which it has Load for each Obligation Procurement Period. The Locational Minimum Unforced Capacity Requirement for each Locality shall equal the product of the Locational Minimum Installed Capacity Requirement for a given Locality ((A) with or without the UDRs if there is a capability year adjustment election by a rights holder and (B) without the Locality Exchange MW) and the ratio of (1) the total amount of Unforced Capacity that the specified Resources are qualified to provide (with or without the UDRs associated with dissimilar capability periods, as so elected by the rights holder) during each month in the Capability Period, as of the time the Locational Minimum Unforced Capacity Requirement is determined as specified in ISO Procedures, to (2) the sum of the DMNCs used to determine the Unforced Capacities of such Resources for such Capability

Period (with or without the DMNCs associated with the UDRs, as so elected by the rights holder).

The foregoing calculation shall be determined using the Resources in the given Locality in the most recent final version of the ISO's annual Load and Capacity Data Report, with the addition of Resources commencing commercial operation since completion of that report and the deletion of Resources with scheduled or planned retirement dates before or during such Capability Period. The ISO will apply the Locality Exchange Factor for the applicable External Control Area to the MW of Locational Export Capacity that are the lesser of (i) the lesser of the Generator's CRIS and its most recent DMNC, and (ii) the MW pursuant to the notice provided pursuant to Section 5.9.2.2.1 of this Services Tariff.

Under the provisions of this Services Tariff and the ISO Procedures, each LSE will be obligated to procure its LSE Unforced Capacity Obligation. The LSE Unforced Capacity Obligation will be determined for each Obligation Procurement Period by the ICAP Spot Market Auction, in accordance with the ISO Procedures.

Qualified Resources will have the opportunity to supply amounts of Unforced Capacity to meet the LSE Unforced Capacity Obligation as established by the ICAP Spot Market Auction.

To be counted towards the locational component of the LSE Unforced Capacity Obligation, Unforced Capacity owned by the holder of UDRs or contractually combined with UDRs must be deliverable to the NYCA interface with the UDR transmission facility pursuant to NYISO requirements and consistent with the election of the holder of the rights to the UDRs set forth in this Section.

[***NYISO note: Proposed deletion of the following paragraph because it is obsolete. The MW of generators and UDR projects subject to a BSM Offer Floor, or of a generator that***

is an Interim Service Provider or RMR generator, are only allowed to offer into the ICAP Spot Market Auction.]

~~In addition, any Customer that purchases Unforced Capacity associated with any generation that is subject to capacity market mitigation measures in an ISO-administered auction may not resell that Unforced Capacity in a subsequent auction at a price greater than the annual mitigated price cap, as applied in accordance with the ISO Procedures in accordance with Sections 5.13.2, 5.13.3, and 5.14.1 of this Tariff. The ISO shall inform Customers that purchase Unforced Capacity in an ISO-administered auction of the amount of Unforced Capacity they have purchased that is subject to capacity market mitigation measures.~~

The ISO shall have the right to audit all executed Installed Capacity contracts and related documentation of arrangements by an LSE to use its own generation to meet its Locational Minimum Installed Capacity Requirement for an upcoming Obligation Procurement Period.

5.11.~~4~~6~~.1~~ Determination of Locality Exchange Factor~~:~~

No later than January 31 each year, the ISO shall determine the Locality Exchange Factor for each Import Constrained Locality relative to each neighboring Control Area.

The ISO shall make each such determination by performing a power flow based analysis according to applicable transmission system planning practices for the determination of interface transfer limits used for the resource adequacy topology. Base case data from the most recent reliability planning process will be incorporated. The Locality Exchange Factor is the ratio of the shift factor on the applicable NYCA interface of a transfer from the Import Constrained Locality to the respective neighboring Control Area, to the shift factor of a transfer from Rest of State to the Import Constrained Locality, calculated in accordance with ISO Procedures. Only the AC circuits comprising the respective neighboring Control Area's interface with the NYCA will participate in the shift. The ISO shall post its Locality Exchange Factors on its website prior to the opening of the Summer Capability Period Auction, and notify the New York State Reliability Council.

Exhibit 37

Alternative Methods for Determining LCRs: Final Market Design

Zachary Stines
Associate Market Design Specialist

Business Issues Committee

February 14, 2018, NYISO

DRAFT – FOR DISCUSSION PURPOSES ONLY

Agenda

- **2017 Project**
- **Final Market Design**
  - Design Objective
  - Methodology
  - Timeline
- **Tariff**
- **Next Steps**
  - 2018 Implementation
- **Questions**
- **Propose for vote**
- **Appendix**

2017 & 2018 Project Presentations

2017 & 2018 Presentations

Date	Discussion points and links to materials
2-15-17	Recap of 2016 Effort, 2017 Plan, and Current Status
4-04-17	2017 Commitment and Base Case
5-11-17	Proof of Concept and Refining Methodology
6-01-17	Sensitivities and Cost Curves
6-29-17	Sensitivity Results and Refining Methodology
7-25-17	Refining Methodology
8-22-17	Refining Methodology and Transmission Security
9-28-17	Transmission Security, Results, and Timeline
10-30-17	Transmission Security and Results
11-15-17	Final Market Design
1-10-18	Uncollared Net CONE Recommendation
1-25-18	2018 Results for Collared and Uncollared Net CONE
2-06-18	2017 & 2018 Base Case Discussion

Final Market Design

Design Objective

Market Design Statement

Develop a robust, transparent, and intuitive (predictive) process for developing proper capacity requirements that maintain reliability while producing a lower cost solution

Market Guiding Principles

Efficient allocation of capacity

- Maintains reliability
- Cost effective
- Proper investment incentives

Transparent and predictable

- Simple, stable, robust
- Predictable

Methodology

Optimization Methodology

- Determine LCRs for the Localities that minimize total cost of capacity at the level of excess (LOE) condition while maintaining the reliability criterion (LOLE ≤ 0.1 days/year), the NYSRC approved IRM, and not exceeding transmission security limits (TSL)
- Cost defined by uncollared Unit Net CONE used to develop each ICAP Demand Curve

Minimize:

$$
\begin{aligned}
&\mathit{Total\ Cost\ of\ Capacity} \\
&= \left[\sum_X (Q_X + LOE_X) \cdot P_X(Q_X + LOE_X)\right] \\
&+ \left[\sum_Y (Q_Y + LOE_Y) \cdot P_Y\left(Q_Y + LOE_Y + \sum_Z Q_Z + LOE_Z\right)\right] \\
&+ \left[\left(Q_{NYCA} + LOE_{NYCA} - \left(\sum_X (Q_X + LOE_X) + \sum_Y (Q_Y + LOE_Y)\right)\right)\right. \\
&\left. \cdot P_{NYCA}(Q_{NYCA} + LOE_{NYCA})\right]
\end{aligned}
$$

$P =$ Price (*i.e.,* Unit Net CONE curves)

$Q =$ Quantity at 100% requirement (MW)

$LOE =$ Quantity associated with Level of Excess (MW)

$X =$ Single Load Zone that is a Locality (*i.e.,* Zone J and Zone K)

$Y =$ Locality minus any Single Load Zone Locality located within it (*i.e.,* GHI)

$Z =$ Single Locality located within a larger Locality (*i.e.,* Zone J)

$NYCA =$ New York Control Area

Subject to:

$$LOLE \leq 0.1\ days/year$$

$$LCR_J \geq TSL_J$$

$$LCR_K \geq TSL_K$$

$$LCR_{G\text{-}J} \geq TSL_{G\text{-}J}$$

$$IRM = NYSRC\ Approved\ IRM\ (i.e.,\ 18\%)$$

Computational Method: Linear Approximation

- Iterative process between Linear Program wrapper and MARS that approximates the objective function and constraints to find least cost solution
- Currently uses the Constrained Optimization By Linear Approximation (COBYLA) algorithm available through Python's scientific computing package

MARS Modeling Assumptions

- Utilize the same process as currently used to develop the final LCR base case
  - Update the NYSRC approved final IRM topology to account for the updated load forecast
- Optimize with the appropriate NYSRC final approved IRM

NYSRC

- Presented to the NYSRC ICS throughout 2017 to provide information and discuss the methodology and progression of this project
- The proposed methodology will enable the NYISO to meet its compliance obligations under the NYSRC rules

Cost of Capacity

- Based upon ICAP Demand Curve peaking plant net cost of new entry ("DC unit net CONE") of capacity within each Locality and the NYCA
- Based upon the FERC accepted Demand Curve parameters
- Elasticity is represented by expressing the DC unit net CONE of each Locality and NYCA as a function of the minimum installed capacity requirement

Development of DC unit net CONE Curves

- Evaluate Net EAS at different levels of installed capacity using data from the most recent of either the Capability Year after a quadrennial Demand Curve Reset or the annual update
  - In developing the proposal, Net EAS for each Locality was evaluated at +6%, +3%, 2016 requirement, -3%, and -6% of the installed capacity requirement
- Results are used to develop a Net EAS curve
- The Net EAS at each point on the curve is used to calculate a corresponding uncollared Net CONE
- Net CONE values are used to develop a uncollared DC unit net CONE curve for each Locality and NYCA

Transmission Security Methodology

- N-1-1 analysis is conducted to determine the transmission security import limits into each Locality
- These import limits are used to determine the minimum available capacity required for each Locality
- To translate this minimum available capacity into a market requirement the methodology needs to account for capacity unavailability
- To account for capacity unavailability, the 5-year zonal EFORd is used to calculate minimum locational capacity requirements

N-1-1 Transmission Security Limit (TSL) Analysis

- Analyzes the N-1-1 thermal transfer limits for the NYCA interfaces associated with the G-J, Zone J, and Zone K Localities
- Use an updated Summer Operating base case
  - Inclusion of transmission and generation facility additions and retirements
  - All system elements modeled as in service
  - Appropriate load forecast
- Report with N-1-1 import limits will be posted prior to October 1st of each year
- Final TSLs for the optimization will be established and posted in January each year

NEW YORK INDEPENDENT SYSTEM OPERATOR

Example Calculation

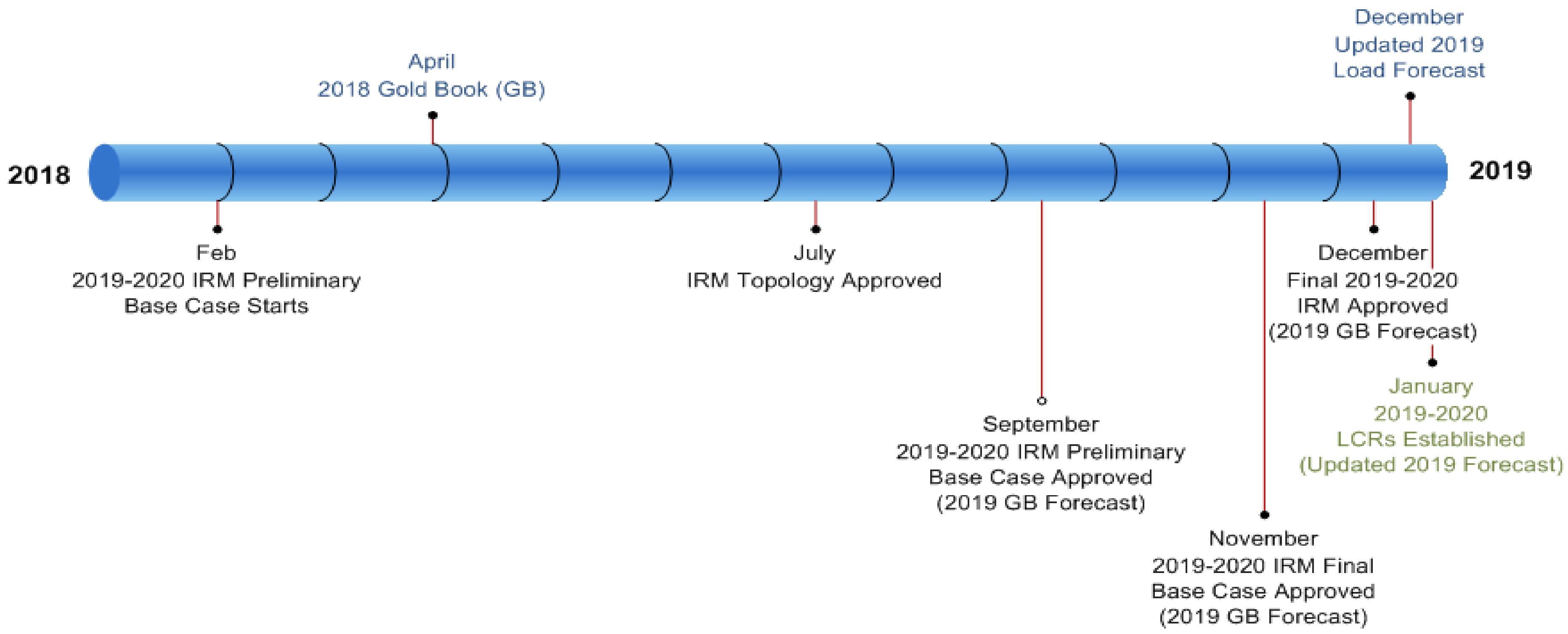
Transmission Security Requirements	Formula	Zone X
Load Forecast (MW)	[A] = Given	12,000
Transmission Security Import Limit (MW)	[B] = Given	1,500
Transmission Security UCAP Requirement (MW)	[C] = [A]-[B]	10,500
Transmission Security UCAP Requirement (%)	[D] = [C]/[A]	87.5%
5 Year EFORd (%)	[E] = Given	8.0%
Transmission Security ICAP Requirement (MW)	[F] = [C]/(1-[E])	11,413
Transmission Security LCR Floor (%)	[G] = [F]/[A]	**95.1%**

NEW YORK INDEPENDENT SYSTEM OPERATOR

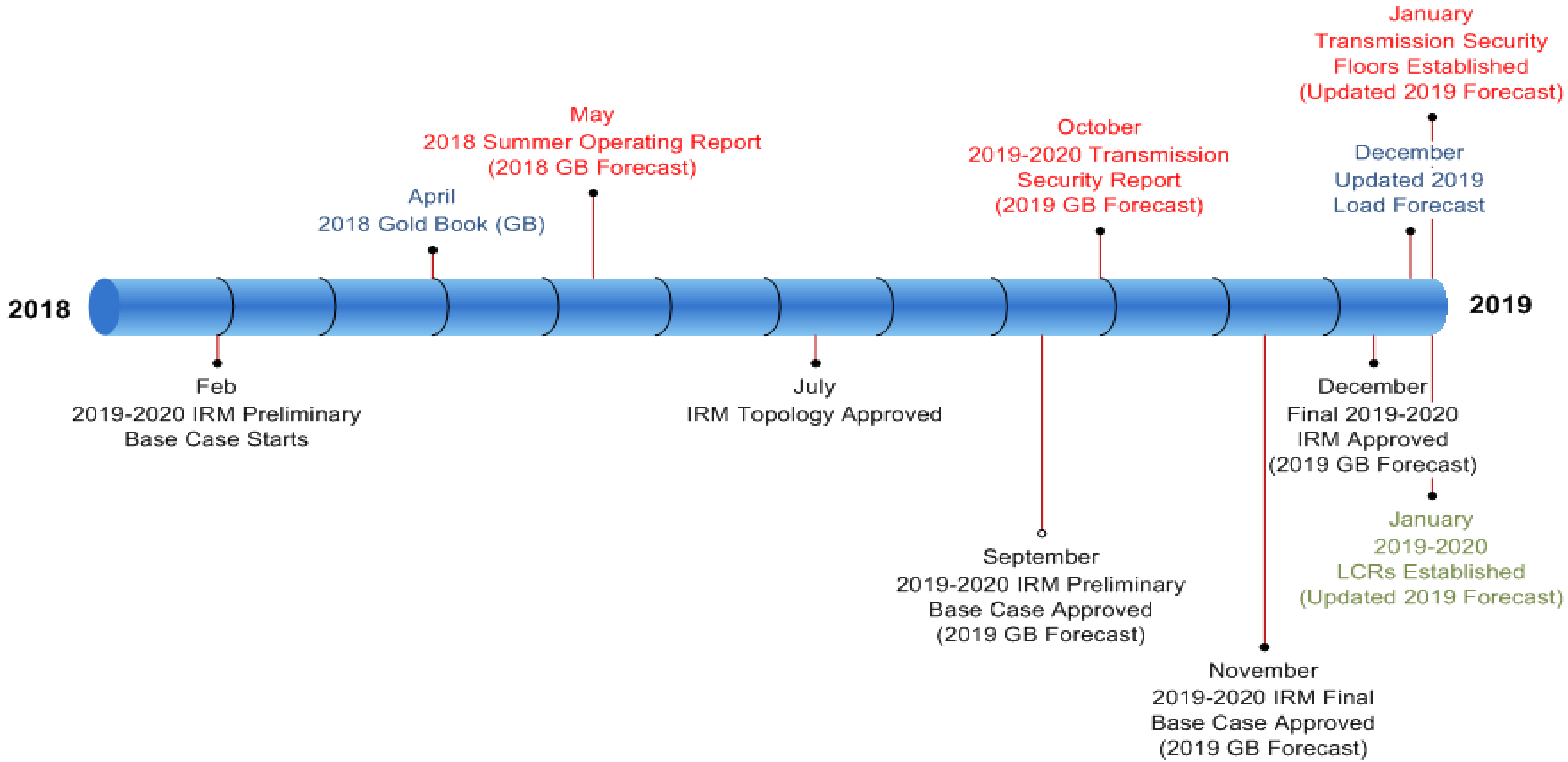
DRAFT – FOR DISCUSSION PURPOSES ONLY

Timeline

Current Timeline



Timeline Additions



LCR Setting Timeline

- No alterations to the current timeline are needed to accommodate the alternative methodology for determining LCRs
- Transmission security analysis used in the alternative methodology would be conducted and reported prior to October 1st
  - This analysis would utilize an updated base case used in the Summer Operating Report

NEW YORK INDEPENDENT SYSTEM OPERATOR

Tariff

Tariff Revisions

- Revisions to
  - MST 5.11
- Incremental revisions based on stakeholder input at the February 6, 2018 ICAP Working Group/MIWG meeting have been incorporated in the proposed tariff revisions

NEW YORK INDEPENDENT SYSTEM OPERATOR

Next Steps

2018 Project Plan

- **Project Plan:**
  - Seek approval and file tariff revisions with FERC
  - Update documentation, procedures, and processes
  - Internal training
  - Development of production software
  - User acceptance testing of production software
  - Deployment of production software

2018 Required Resources

- **Resources:**
  - GE Energy Consulting
  - ICAP Market Design
  - Resource Adequacy
  - ICAP Market Operations
  - Operations Engineering
  - Legal

2018 Project Milestones

- February 14: Business Issues Committee
- February 28: Management Committee
- March 20: Board of Directors
- March 30: File Section 205 with FERC
- April: Updating documentation, procedures, processes
- June: FERC action
- June 29: Production Version Complete
- July: User Acceptance Testing
- September: Production Deployment

Questions?

The Mission of the New York Independent System Operator, in collaboration with its stakeholders, is to serve the public interest and provide benefits to consumers by:

- Maintaining and enhancing regional reliability
- Operating open, fair and competitive wholesale electricity markets
- Planning the power system for the future
- Providing factual information to policy makers, stakeholders and investors in the power system

www.nyiso.com

NEW YORK INDEPENDENT SYSTEM OPERATOR

Exhibit 38

Consumer Impact Analysis Using the 2018 Base case: Alternative Methods for Determining LCRs

Tariq N. Niazi

Senior Manager, Consumer Interest Liaison

THIS PPT UPDATES THE PPT POSTED FOR THE FEBRUARY 22 ICAPWG MEETING. The update is to the Long Term Cost at Historic Excess (Slide 12 and 16). The slides presented on February 22 were based on inadvertently transposing Localities' and ROS historic LOEs.

Installed Capacity Working Group

February 22, 2018 - REVISED February 27, 2018

NEW YORK INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY

Background/Overview

- The initial Consumer Impact Analysis for Alternative Methods for Determining LCRs was presented to stakeholders at the October 11, 2017 ICAPWG meeting
- During that presentation, some stakeholders requested additional information which was provided to stakeholders in another presentation (Additional Consumer Impact Analysis) at the November 6, 2017 ICAPWG meeting
- At the February 6, 2018 ICAPWG meeting the NYISO presented updated LCRs based on the 2018 base case
- During the February 14 BIC meeting, some stakeholders requested that the consumer impact analysis be updated using the 2018 base case since the prior analyses were based on the 2017 base case
- This presentation updates the Consumer Impact Analysis based on the 2018 base case as requested by stakeholders

Changes from the 2017 to the 2018 Base Case

- As discussed at the February 6, 2018 ICAP meeting, the 2018 base case required more capacity in southeast New York to meet the reliability criteria of LOLE<0.1 days/year than the 2017 base case required
  - This was observed using both the current and optimized LCR methodologies
- The increase from 2017 to 2018 were mainly a result of the following:
  - Increase in Load Forecast Uncertainty in Zones J and K
  - Changes in Interface Limits
  - Increased EFORd on underground transmission cables and UDRs
- The following changes were also made between 2017 to 2018:
  - Increase in Demand Curve Net CONE cost curves
  - Transmission Security LCR Floors

2017 and 2018 LCRs (%)

	Approved LCRs			Optimized LCRs		
	G-J	J	K	G-J	J	K
2017	91.5%	81.5%	103.5%	90.7%	80.2%	104.2%
2018	94.5%	80.5%	103.5%	90.8%	79.7%	107.5%

2017 and 2018 LCRs (MW)

	Approved LCRs (MW)			Optimized LCRs (MW)		
	G-J	J	K	G-J	J	K
2017	14,696.1	9,511.1	5,617.0	14,569.8	9,354.7	5,652.5
2018	15,042.5	9,288.9	5,605.6	14,432.0	9,198.2	5,856.1
Δ Locality MW	346.4	-222.2	-11.5	-137.9	-156.5	203.6
Δ Southeast New York MW	334.9			65.7		

- **While both the current and optimized methodology required an increase in southeast New York capacity from 2017 to 2018, the optimized methodology was able to achieve a solution that minimizes this increase in capacity while also reducing total statewide cost**

Cost Impact Analysis

- **The tables that follow provide the Consumer Impact Analysis based on the 2018 base case**
- **The Consumer Impact Analysis follows the following format**
  - Short term consumer impact assumes no changes in generation from the 2017 Consumer Impact Analysis
  - Long term cost impact
    - Long-run equilibrium modelled at the Level of Excess condition (defined in the Demand Curve reset)
    - Historic excess defined as a percentage of excess above the requirement (observed in the last 3 Capability Years in each of the different Localities)
- **This analysis looks only at the base case both in the short and long run. Sensitivities around changes in generation, transmission and net CONE would require MARs runs**

NEW YORK INDEPENDENT SYSTEM OPERATOR

Cost Impact Analysis, Contd.

- The cost of capacity shown in the tables for both the current LCRs and optimized LCRs with the updated Transmission Security Limit (TSL) are based on the individual Locality requirement and total capacity that cleared in each Locality
- Additionally, the tables that follow show the delta between the cost of capacity for the current and optimized LCRs
- Assumptions for the analysis
  - 2018 load forecast
  - 2018 approved and optimized LCRs
  - 2018 Reference prices
  - 2017 Supply assumptions used for the Consumer Impact Analysis presented on November 6, 2017 ICAPWG meeting

NEW YORK INDEPENDENT SYSTEM OPERATOR

2018 Total Cost of Capacity

2018 Total Cost of Capacity

- The following costs presented assume that all capacity is purchased at the spot market auction clearing price, and therefore could differ from observed costs if capacity was purchased through other methods (*i.e.*, bilateral contracts or self supply)
- The cost of capacity presented is for the 2018 Capability Year and is to provide a hypothetical outcome based on the described assumptions and using the optimization methodology
- This analysis was based on the 2018 load forecast, projected 2018 reference prices, 2018 approved LCRs and optimized LCRs while utilizing the 2017 supply assumptions from the Consumer Impact Analysis presented at the ICAPWG on November 6, 2017

2018 Short Term Cost

Methodology	2018 Short Term Cost of Capacity (million $)				
	LI	NYC	GHI	ROS	Total
Current Methodology	$303	$1,179	$576	$649	$2,706
Optimized Methodology	$553	$668	$308	$649	$2,178
Delta	$251	-$511	-$268	$0	-$528

- Given the slope of the demand curve, approximately 200 MW of additional capacity, load reduction, or a combination of additions and reductions in Long Island could return the Long Island cost back to that observed under the current method (*i.e.*, about $303 MM), all else equal
- This analysis was based on the 2018 load forecast, 2018 reference prices, 2018 approved and optimized LCRs while utilizing the 2017 supply assumptions from the Consumer Impact Analysis presented at the ICAPWG on November 6, 2017

2018 Long Term Cost at LOE

Methodology	2018 Long Term Cost of Capacity at LOE (million $)				
	LI	NYC	GHI	ROS	Total
Current Methodology	$765	$2,061	$972	$2,017	$5,815
Optimized Methodology	$802	$2,037	$880	$2,060	$5,780
Delta	$37	-$23	-$91	$43	-$35

- This analysis was based on the 2018 load forecast, 2018 reference prices, 2018 approved and optimized LCRs while utilizing the 2017 supply assumptions from the Consumer Impact Analysis presented at the ICAPWG meeting on November 6, 2017

NEW YORK INDEPENDENT SYSTEM OPERATOR

Updated -

2018 Long Term Cost at Historic Excess

Methodology	2018 Long Term Cost of Capacity at Historic Excess (million $)				
	LI	NYC	GHI	ROS	Total
Current Methodology	~~$507~~ $383	$1,121	~~$308~~ $521	~~$731~~ $551	~~$2,667~~ $2,576
Optimized Methodology	~~$527~~ $398	$1,109	~~$281~~ $473	~~$748~~ $562	~~$2,665~~ $2,542
Delta	~~$20~~ $15	-$11	~~-$27~~ -$48	~~$17~~ $11	~~-$2~~ -$34

- This analysis was based on the 2018 load forecast, 2018 reference prices, 2018 approved and optimized LCRs while utilizing the 2017 supply assumptions from the Consumer Impact Analysis presented at the ICAPWG meeting on November 6, 2017

NEW YORK INDEPENDENT SYSTEM OPERATOR

2017 Total Cost of Capacity

2017 Short Term Cost

Methodology	2017 Short Term Cost of Capacity (million $)				
	LI	NYC	GHI	ROS	Total
Current Methodology	$313	$1,011	$348	$714	$2,385
Optimized Methodology	$365	$796	$322	$714	$2,197
Delta	$52	-$215	-$26	$0	-$189

- These results were presented for the Consumer Impact Analysis at the November 6, 2017 ICAPWG meeting

2017 Long Term Cost at LOE

Methodology	2017 Long Term Cost of Capacity at LOE (million $)				
	LI	NYC	GHI	ROS	Total
Current Methodology	$689	$1,887	$782	$1,888	$5,245
Optimized Methodology	$697	$1,855	$789	$1,893	$5,234
Delta	$8	-$32	$7	$5	-$12

- These results were presented for the Consumer Impact Analysis at the November 6, 2017 ICAPWG meeting

Updated -
2017 Long Term Cost at Historic Excess

Methodology	2017 Long Term Cost of Capacity at Historic Excess (million $)				
	LI	NYC	GHI	ROS	Total
Current Methodology	~~$456~~ $344	$1,023	~~$249~~ $418	~~$685~~ $514	~~$2,412~~ $2,299
Optimized Methodology	~~$460~~ $347	$1,007	~~$251~~ $423	~~$687~~ $516	~~$2,405~~ $2,293
Delta	~~$4~~ $3	-$15	~~$2~~ $5	~~$2~~ $1	~~-$7~~ -$6

- These results were presented for the Consumer Impact Analysis at the November 6, 2017 ICAPWG meeting

NEW YORK INDEPENDENT SYSTEM OPERATOR

Feedback?

- Email additional feedback to:
- deckels@nyiso.com

Questions?

We are here to help. Let us know if we can add anything.

The Mission of the New York Independent System Operator, in collaboration with its stakeholders, is to serve the public interest and provide benefits to consumers by:

- Maintaining and enhancing regional reliability
- Operating open, fair and competitive wholesale electricity markets
- Planning the power system for the future
- Providing factual information to policy makers, stakeholders and investors in the power system

www.nyiso.com

NEW YORK INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY

Exhibit 39

Alternative Methods for Determining LCRs: Final Market Design

Zachary Stines
Associate Market Design Specialist

Management Committee

February 28, 2018, NYISO

NEW YORK INDEPENDENT SYSTEM OPERATOR

Agenda

- **2017 Project**
- **Final Market Design**
  - Design Objective
  - Methodology
  - Timeline
- **Tariff**
- **Questions**
- **Propose for vote**
- **Appendix**

2017 & 2018 Project Presentations

2017 & 2018 Presentations

Date	Discussion points and links to materials
2-15-17	Recap of 2016 Effort, 2017 Plan, and Current Status
4-04-17	2017 Commitment and Base Case
5-11-17	Proof of Concept and Refining Methodology
6-01-17	Sensitivities and Cost Curves
6-29-17	Sensitivity Results and Refining Methodology
7-25-17	Refining Methodology
8-22-17	Refining Methodology and Transmission Security
9-28-17	Transmission Security, Results, and Timeline
10-30-17	Transmission Security and Results
11-15-17	Final Market Design
1-10-18	Uncollared Net CONE Recommendation
1-25-18	2018 Results for Collared and Uncollared Net CONE
2-06-18	2017 & 2018 Base Case Discussion

NEW YORK INDEPENDENT SYSTEM OPERATOR

Final Market Design

Design Objective

Market Design Statement

Develop a robust, transparent, and intuitive (predictive) process for developing proper capacity requirements that maintain reliability while producing a lower cost solution

NEW YORK INDEPENDENT SYSTEM OPERATOR

Methodology

Optimization Methodology

- Determine LCRs for the Localities that minimize total cost of capacity at the level of excess (LOE) condition while maintaining the reliability criterion (LOLE ≤ 0.1 days/year), the NYSRC approved IRM, and not exceeding transmission security limits (TSL)
- Cost defined by uncollared Unit Net CONE used to develop each ICAP Demand Curve

NEW YORK INDEPENDENT SYSTEM OPERATOR

MARS Modeling Assumptions

- Utilize the same process as currently used to develop the final LCR base case
  - Update the NYSRC approved final IRM topology to account for the updated load forecast and any material capability changes
- Optimize with the appropriate NYSRC final approved IRM

NYSRC

- Presented to the NYSRC ICS throughout 2017 to provide information and discuss the methodology and progression of this project
- The proposed methodology will enable the NYISO to meet its compliance obligations under the NYSRC rules

Cost of Capacity

- Based upon ICAP Demand Curve peaking plant net cost of new entry ("DC unit net CONE") of capacity within each Locality and the NYCA
- Based upon the FERC accepted Demand Curve parameters
- Elasticity is represented by expressing the DC unit net CONE of each Locality and NYCA as a function of the minimum installed capacity requirement

NEW YORK INDEPENDENT SYSTEM OPERATOR

Transmission Security Methodology

- N-1-1 analysis is conducted to determine the transmission security import limits into each Locality
- These import limits are used to determine the minimum available capacity required for each Locality
- To translate this minimum available capacity into a market requirement the methodology needs to account for capacity unavailability
- To account for capacity unavailability, the 5-year zonal EFORd is used to calculate minimum locational capacity requirements

Example Calculation

Transmission Security Requirements	Formula	Zone X
Load Forecast (MW)	[A] = Given	12,000
Transmission Security Import Limit (MW)	[B] = Given	1,500
Transmission Security UCAP Requirement (MW)	[C] = [A]-[B]	10,500
Transmission Security UCAP Requirement (%)	[D] = [C]/[A]	87.5%
5 Year EFORd (%)	[E] = Given	8.0%
Transmission Security ICAP Requirement (MW)	[F] = [C]/(1-[E])	11,413
Transmission Security LCR Floor (%)	[G] = [F]/[A]	**95.1%**

NEW YORK INDEPENDENT SYSTEM OPERATOR

Timeline

LCR Setting Timeline

- No alterations to the current timeline are needed to accommodate the alternative methodology for determining LCRs
- Transmission security analysis used in the alternative methodology will be conducted and the results will be posted to the NYISO's website

NEW YORK INDEPENDENT SYSTEM OPERATOR

Tariff

Tariff Revisions

- Revisions to
  - MST 5.11
- Incremental revisions based on stakeholder input at the February 6, 2018 ICAP Working Group/MIWG meeting have been incorporated in the proposed tariff revisions

Questions?

The Mission of the New York Independent System Operator, in collaboration with its stakeholders, is to serve the public interest and provide benefits to consumers by:

- Maintaining and enhancing regional reliability
- Operating open, fair and competitive wholesale electricity markets
- Planning the power system for the future
- Providing factual information to policy makers, stakeholders and investors in the power system

www.nyiso.com

NEW YORK INDEPENDENT SYSTEM OPERATOR

DRAFT – FOR DISCUSSION PURPOSES ONLY

Appendix

Market Guiding Principles

Efficient allocation of capacity

- Maintains reliability
- Cost effective
- Proper investment incentives

Transparent and predictable

- Simple, stable, robust
- Predictable

NEW YORK INDEPENDENT SYSTEM OPERATOR

Methodology

Minimize:

$$
\begin{aligned}
&\mathit{Total\ Cost\ of\ Capacity} \\
&= \left[\sum_X (Q_X + LOE_X) \cdot P_X(Q_X + LOE_X)\right] \\
&+ \left[\sum_Y (Q_Y + LOE_Y) \cdot P_Y\left(Q_Y + LOE_Y + \sum_Z Q_Z + LOE_Z\right)\right] \\
&+ \left[\left(Q_{NYCA} + LOE_{NYCA} - \left(\sum_X (Q_X + LOE_X) + \sum_Y (Q_Y + LOE_Y)\right)\right)\right. \\
&\left.\cdot P_{NYCA}(Q_{NYCA} + LOE_{NYCA})\right]
\end{aligned}
$$

DRAFT – FOR DISCUSSION PURPOSES ONLY

$P =$ Price (*i.e.,* Unit Net CONE curves)

$Q =$ Quantity at 100% requirement (MW)

$LOE =$ Quantity associated with Level of Excess (MW)

$X =$ Single Load Zone that is a Locality (*i.e.,* Zone J and Zone K)

$Y =$ Locality minus any Single Load Zone Locality located within it (*i.e.,* GHI)

$Z =$ Single Locality located within a larger Locality (*i.e.,* Zone J)

$NYCA =$ New York Control Area

NEW YORK INDEPENDENT SYSTEM OPERATOR

Subject to:

$$LOLE \leq 0.1 \ days/year$$

$$LCR_J \geq TSL_J$$

$$LCR_K \geq TSL_K$$

$$LCR_{G\text{-}J} \geq TSL_{G\text{-}J}$$

$$IRM = NYSRC \ Approved \ IRM \ (i.e., \ 18\%)$$

NEW YORK INDEPENDENT SYSTEM OPERATOR

Computational Method: Linear Approximation

- Iterative process between Linear Program wrapper and MARS that approximates the objective function and constraints to find least cost solution
- Currently uses the Constrained Optimization By Linear Approximation (COBYLA) algorithm available through Python's scientific computing package

NEW YORK INDEPENDENT SYSTEM OPERATOR

Development of DC unit net CONE Curves

- Evaluate Net EAS at different levels of installed capacity using data from the most recent of either the Capability Year after a quadrennial Demand Curve Reset or the annual update
  - In developing the proposal, Net EAS for each Locality was evaluated at +6%, +3%, 2016 requirement, -3%, and -6% of the installed capacity requirement
- Results are used to develop a Net EAS curve
- The Net EAS at each point on the curve is used to calculate a corresponding uncollared Net CONE
- Net CONE values are used to develop a uncollared DC unit net CONE curve for each Locality and NYCA

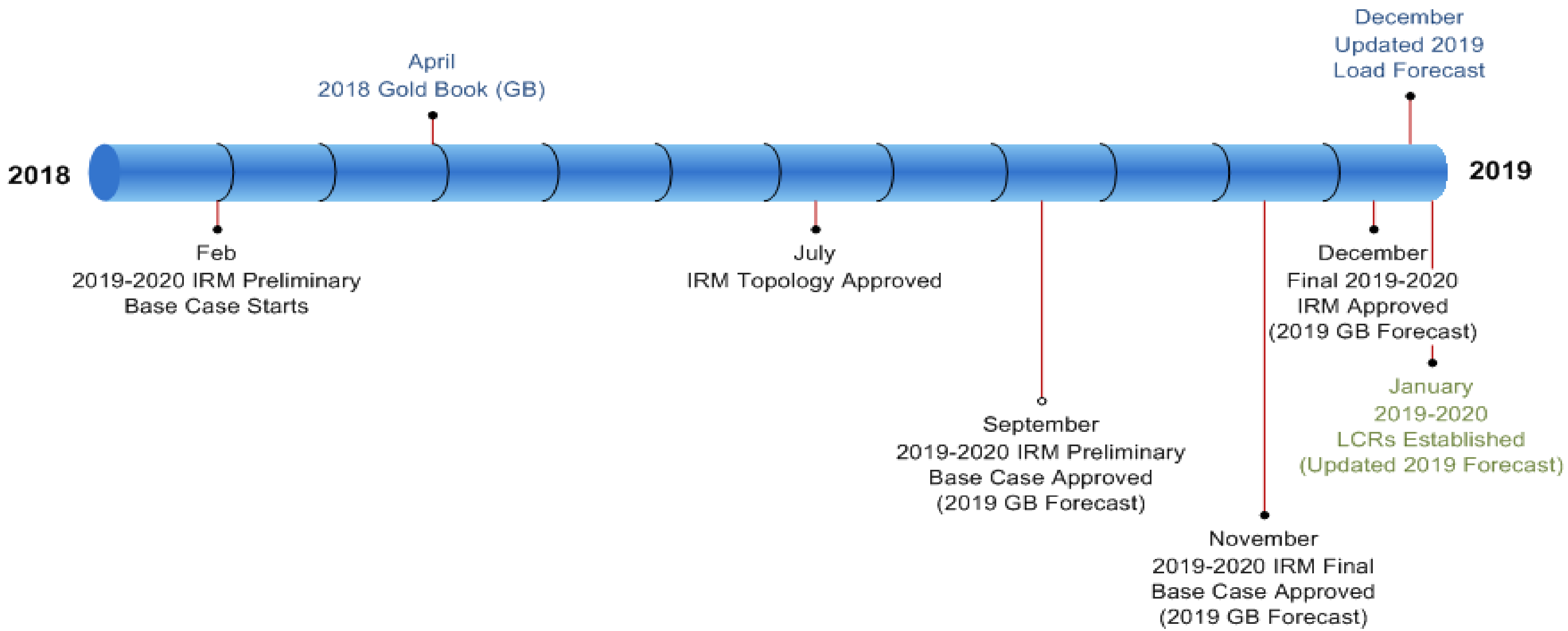
NEW YORK INDEPENDENT SYSTEM OPERATOR

N-1-1 Transmission Security Limit (TSL) Analysis

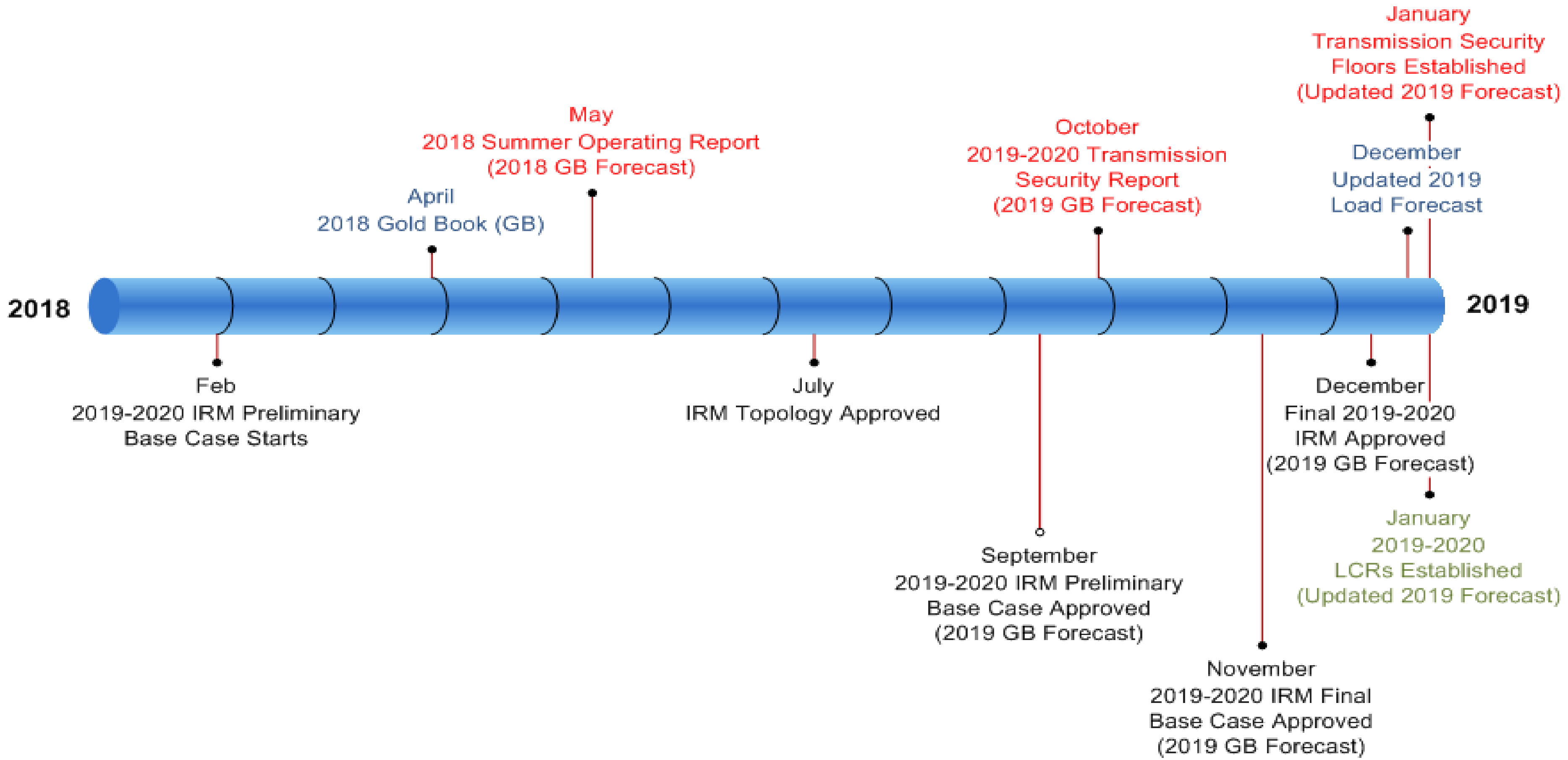
- Analyzes the N-1-1 thermal transfer limits for the NYCA interfaces associated with the G-J, Zone J, and Zone K Localities
- Use an updated Summer Operating base case
  - Inclusion of transmission and generation facility additions and retirements
  - All system elements modeled as in service
  - Appropriate load forecast
- Report with N-1-1 import limits will be posted in October each year
- Final TSLs for the optimization will be established and posted in January each year

Timeline

Current Timeline



Timeline Additions



Next Steps

2018 Project Plan

- **Project Plan:**
  - Seek approval and file tariff revisions with FERC
  - Update documentation, procedures, and processes
  - Internal training
  - Development of production software
  - User acceptance testing of production software
  - Deployment of production software

2018 Required Resources

- Resources:
  - GE Energy Consulting
  - ICAP Market Design
  - Resource Adequacy
  - ICAP Market Operations
  - Operations Engineering
  - Legal

2018 Project Milestones

- February 14: Business Issues Committee
- February 28: Management Committee
- March 20: Board of Directors
- March 30: File Section 205 with FERC
- April: Updating documentation, procedures, processes
- June: FERC action
- June 29: Production Version Complete
- July: User Acceptance Testing
- September: Production Deployment