aeso ALBERTA ELECTRIC SYSTEM OPERATOR

Presentation of 2017 Loss Factors Determined Under Loss Factor Rule

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Topics

- Introductions and agenda (slides 1-2)
- Summary of loss factors and related information posted on AESO website (slides 3-16)
- Overview of loss factor calculations (slides 17-21)
- Loss factor results, including exclusion rates and causes (slides 22-27)
- Examples of outlier loss factors (slides 28-33)
- Shift factor results (slide 34)
- Comparisons of new and prior loss factors (slides 35-37)
- Future loss factor work, including development of 2018 loss factors (slides 38-39)

Please ask questions during presentation

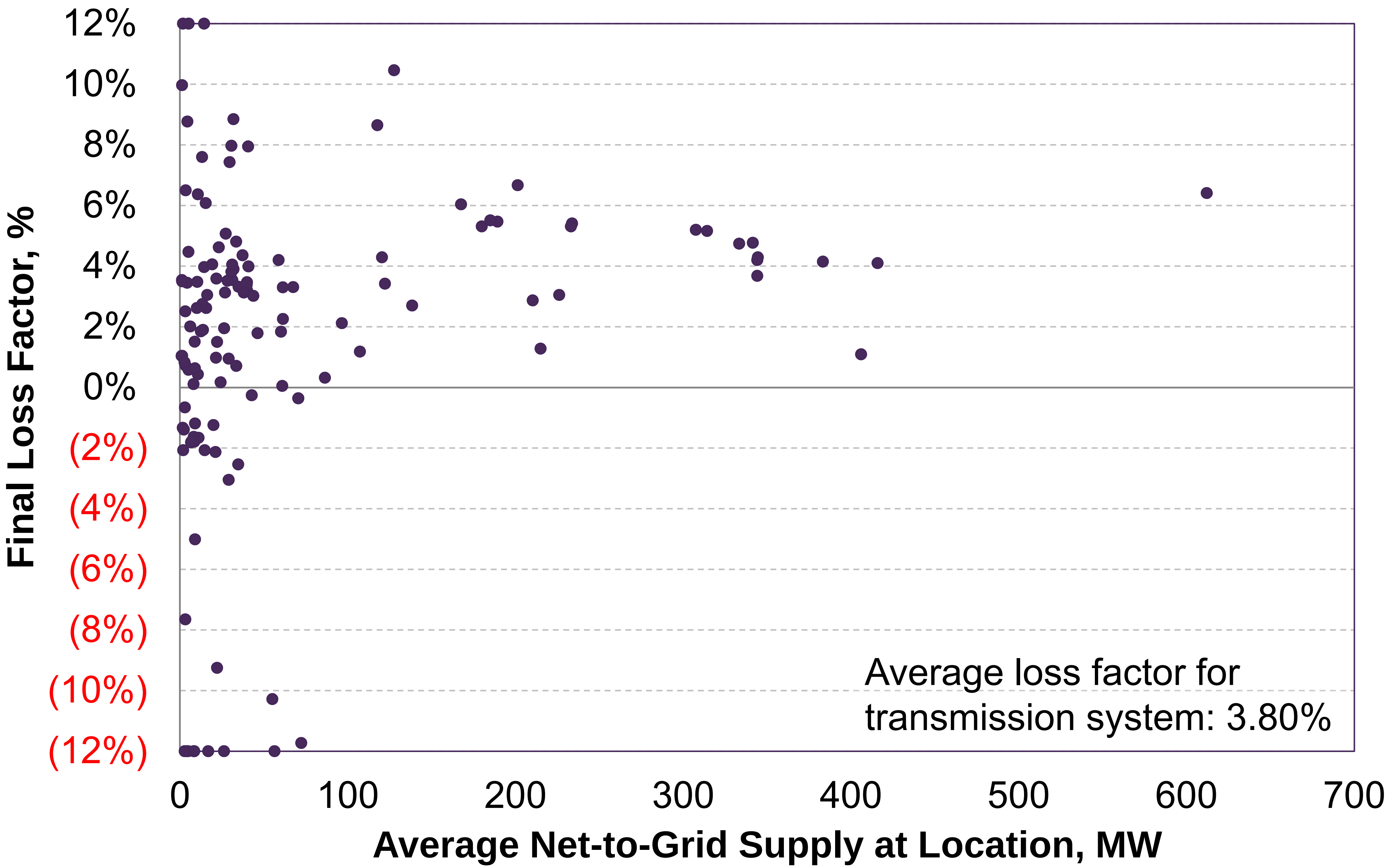
AESO posted 2017 loss factors on its website on May 11, 2017

- Loss factors were posted in accordance with section 501.10 of ISO rules, *Transmission Loss Factors* (“Loss Factor Rule”)
  - Rule was confirmed by Commission in Decision 790-D05-2016 issued on November 30, 2016 regarding AESO’s Phase 2 Module B compliance filing in Proceeding 790
  - Subsection 3(1.1) of Loss Factor Rule requires AESO to publish final loss factors for 2017 as soon as practicable in 2017
  - Loss factors determined under Loss Factor Rule will be effective from January 1, 2017 to December 31, 2017
- Rule requires AESO to publish additional information at same time as loss factors

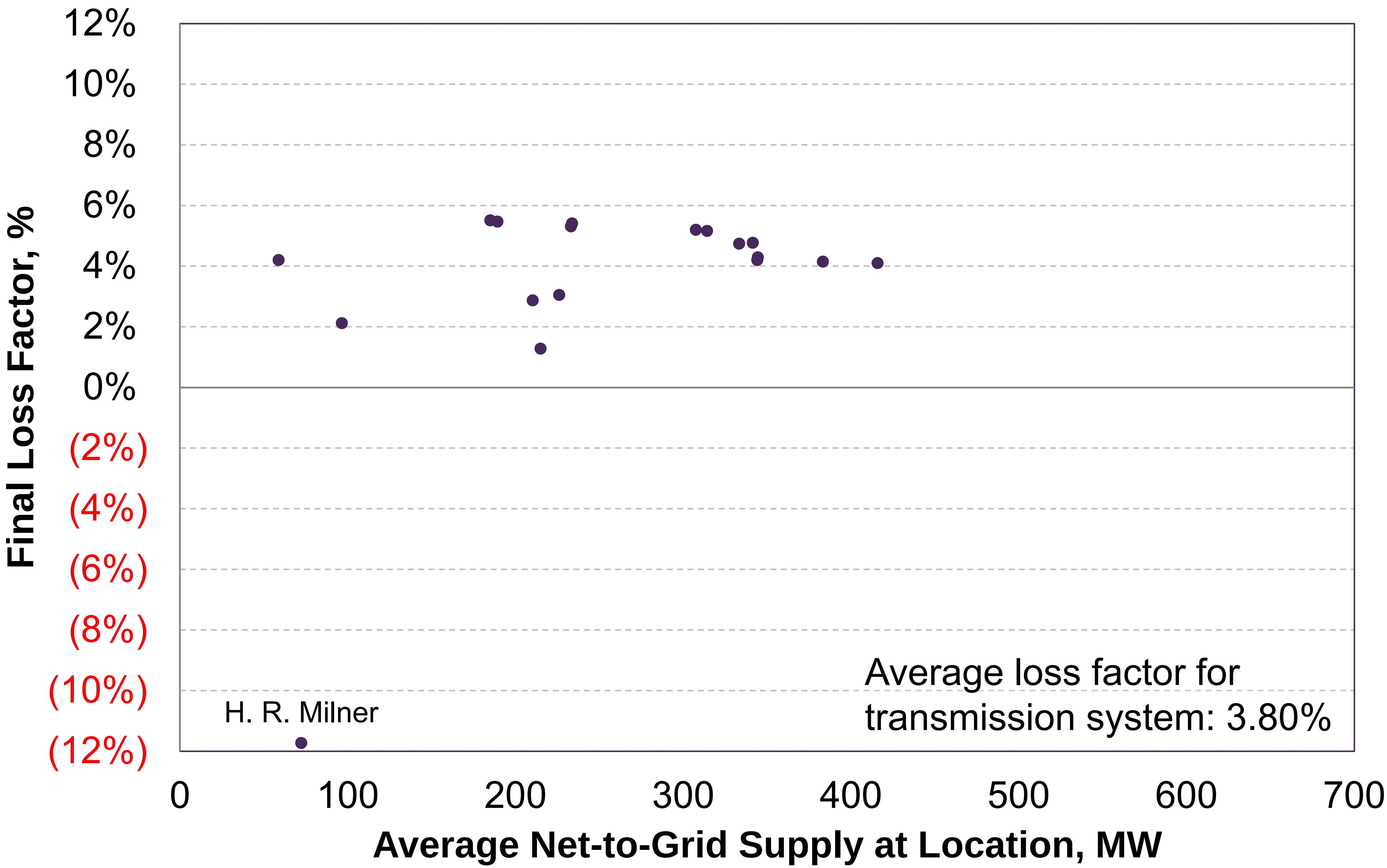
AESO also posted additional information used to establish 2017 loss factors

- Information posted in accordance with subsection 3(2) of the Loss Factor Rule
  – Hourly merit order data for 2017 loss factors
  – Sample of 144 hours of load data for 2017 loss factors
  – Process for requesting access to system topologies
  – Procedure to determine transmission system losses for loss factor calculations
  – Software and scripts used to calculate hourly raw loss factors
  – Workbook showing calculations for 2017 loss factors
- Transmission system losses
  – Anticipated losses of 2,230 GWh for 2017
  – Average loss factor of 3.80% for 2017

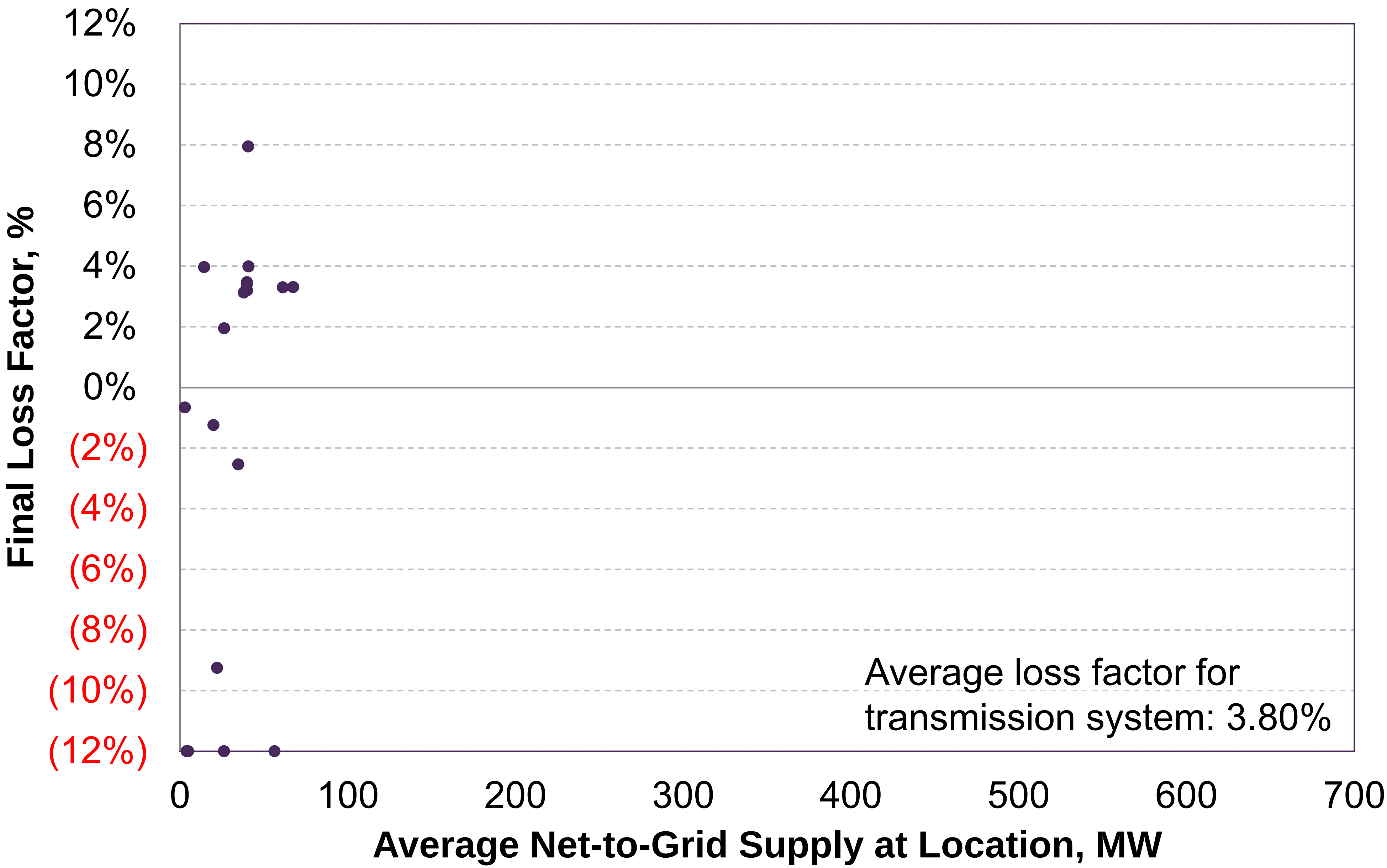
Final loss factors show greater dispersion for smaller average net-to-grid volumes



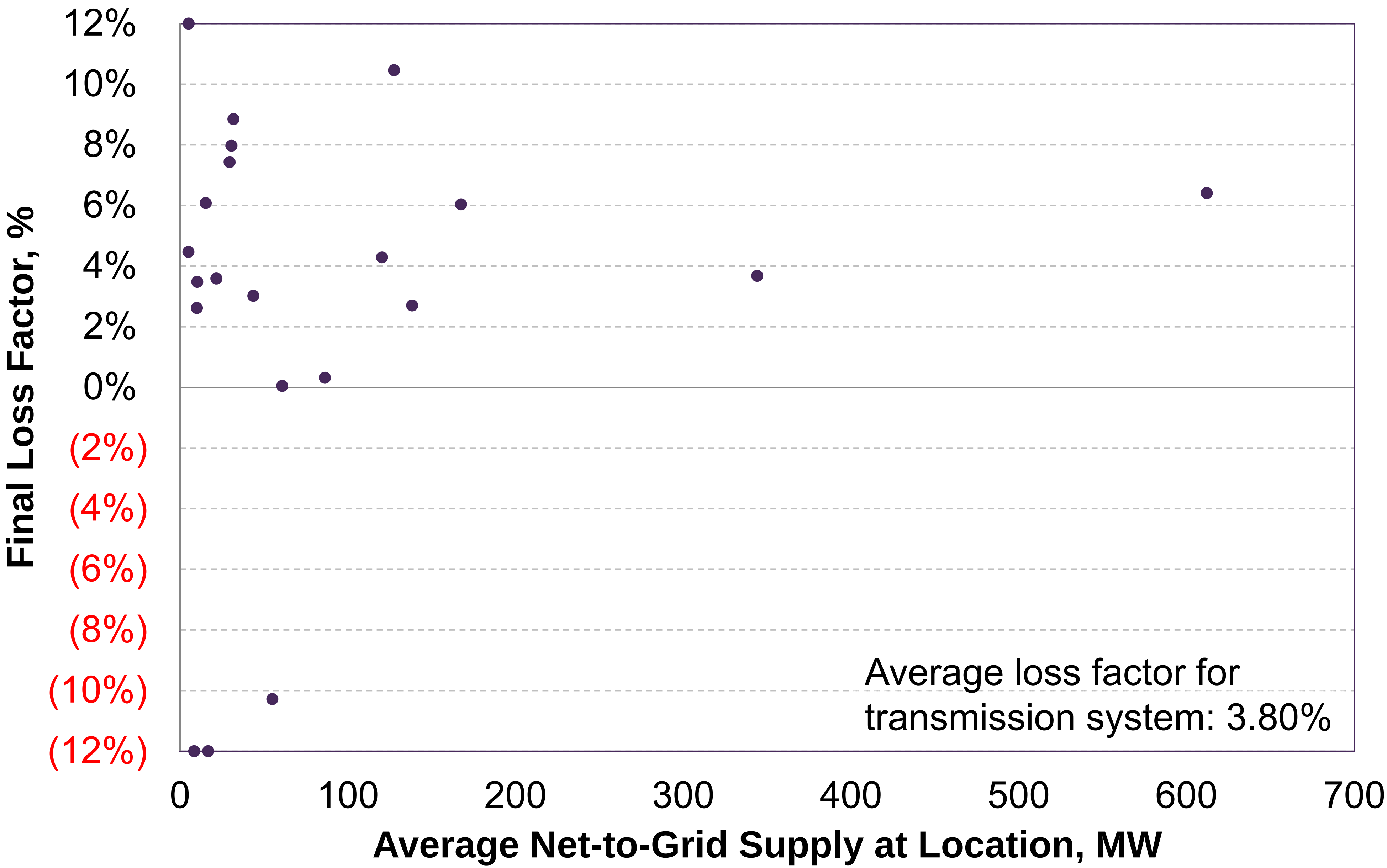
Coal generating facilities show generally less dispersion in loss factors



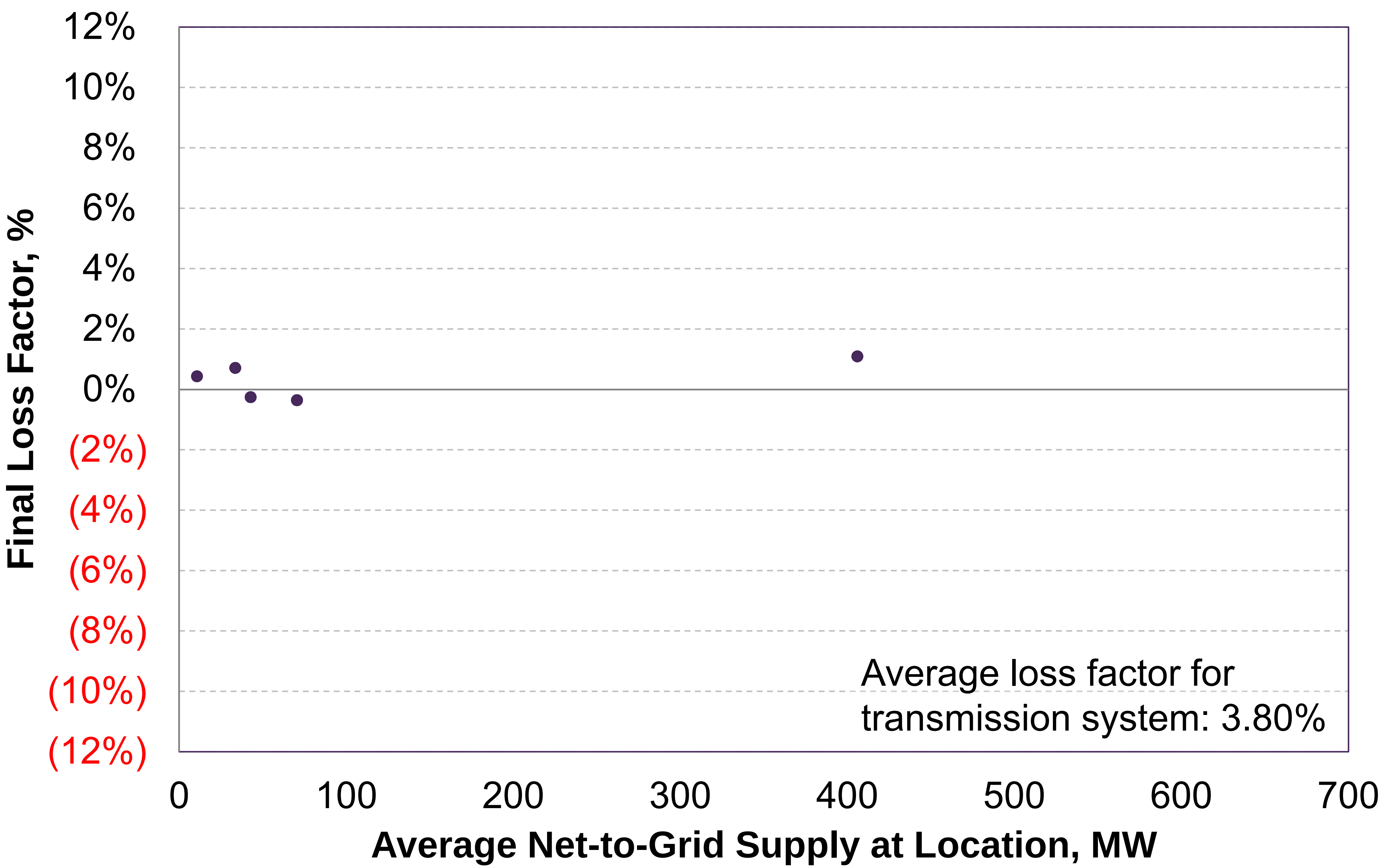
Simple cycle gas generating facilities show more dispersion in loss factors



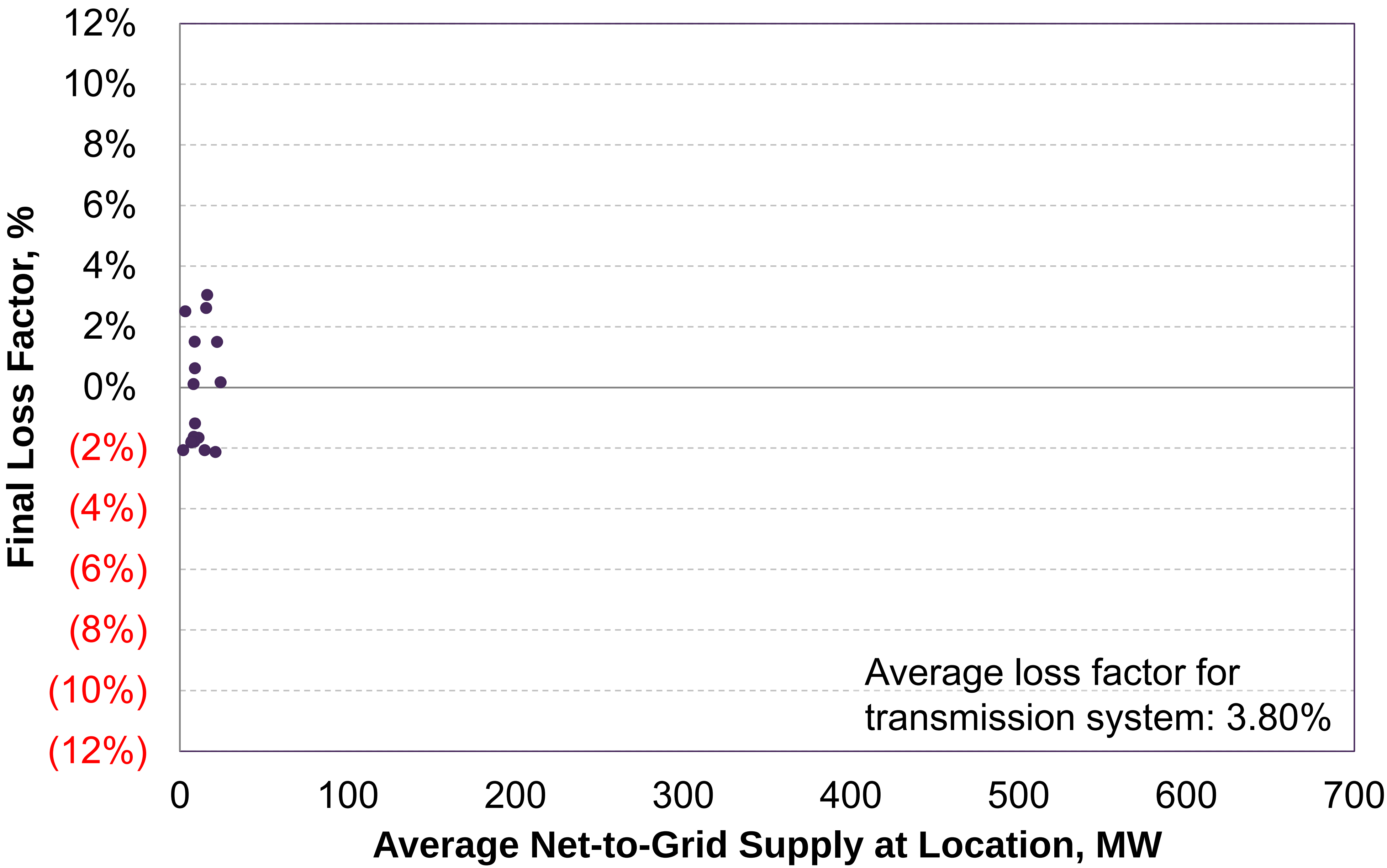
Cogeneration gas generating facilities show more dispersion in loss factors



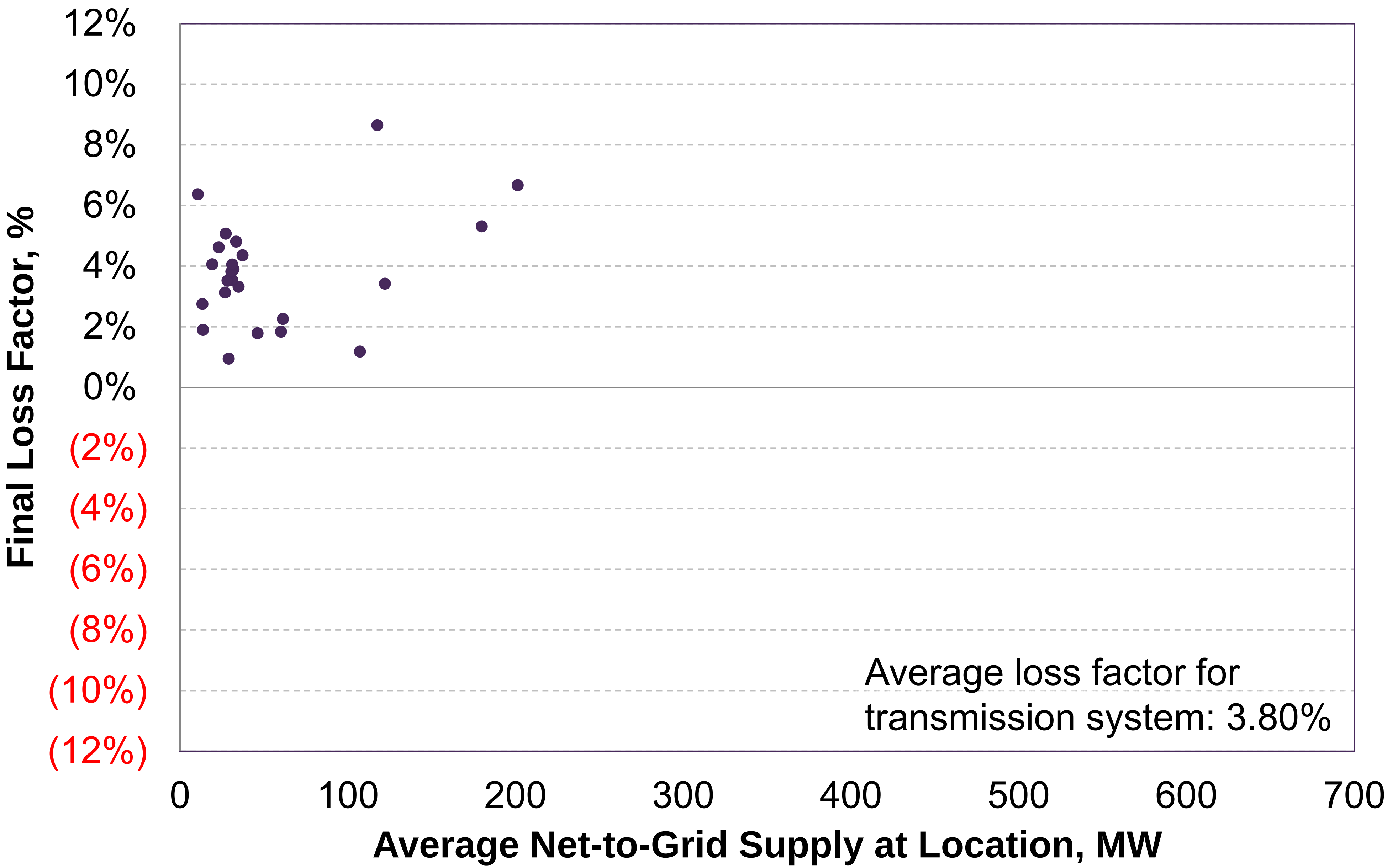
Combined cycle gas generating facilities show less dispersion in loss factors



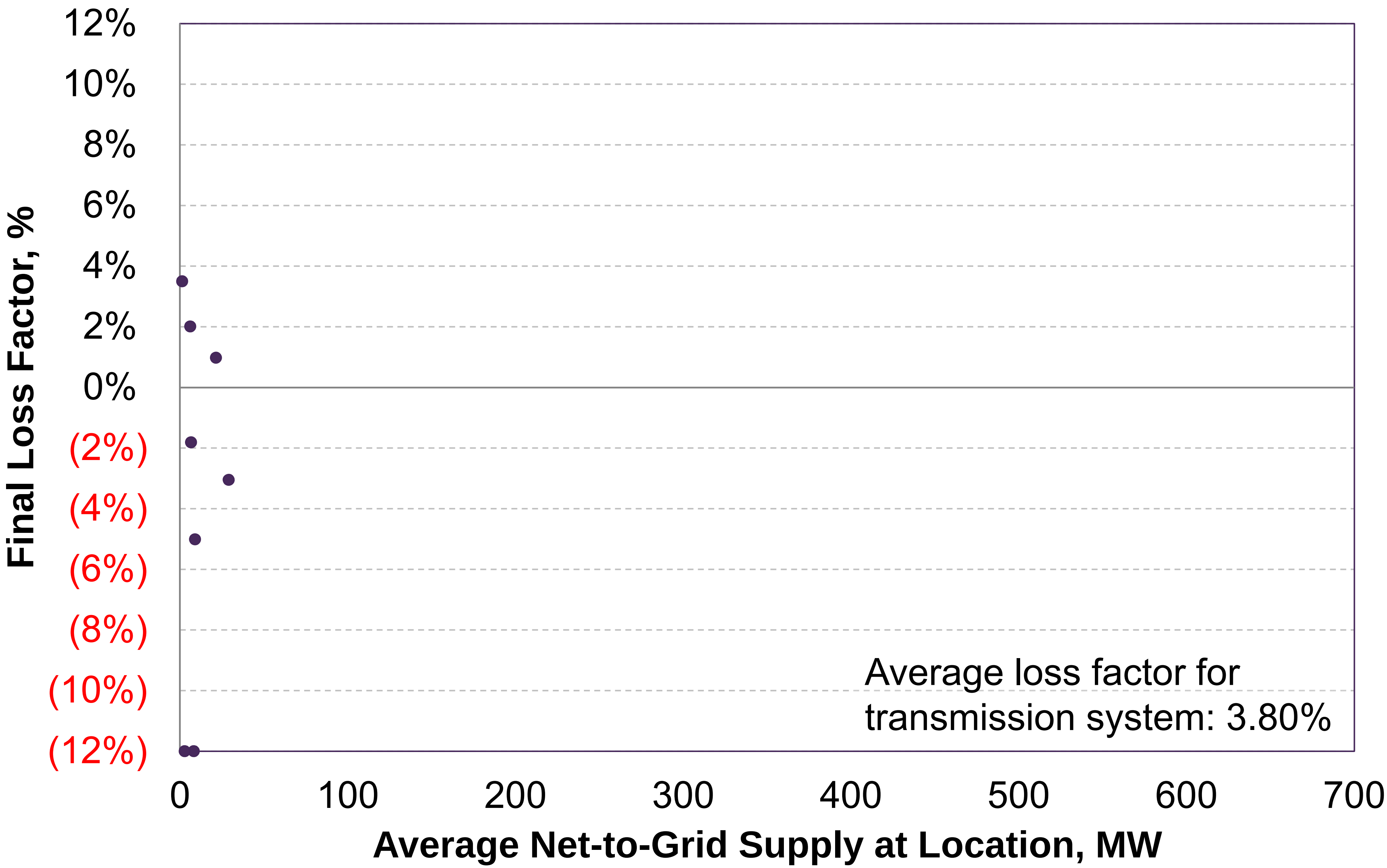
Hydro generating facilities show moderate dispersion in loss factors



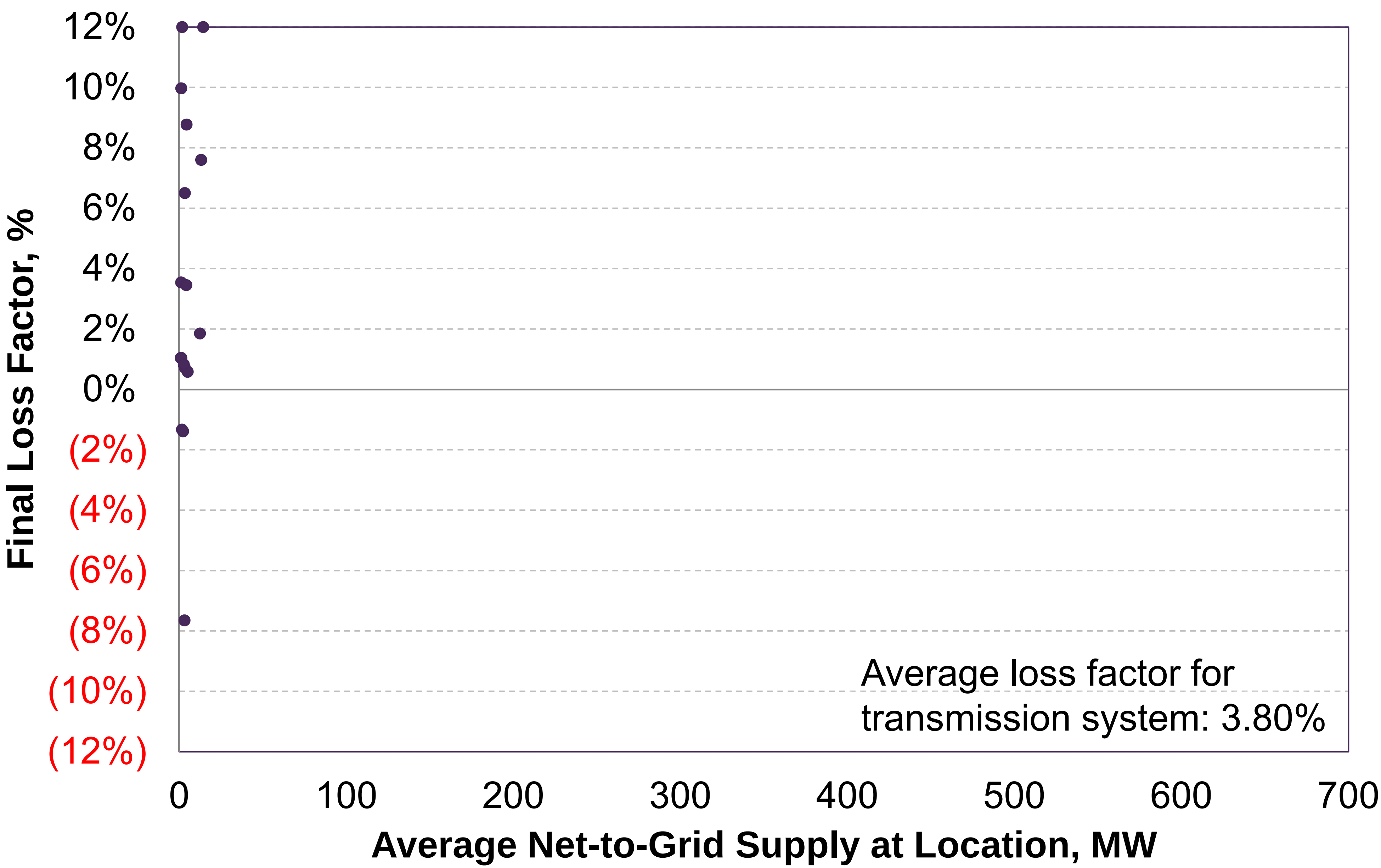
Wind generating facilities show moderate dispersion in loss factors



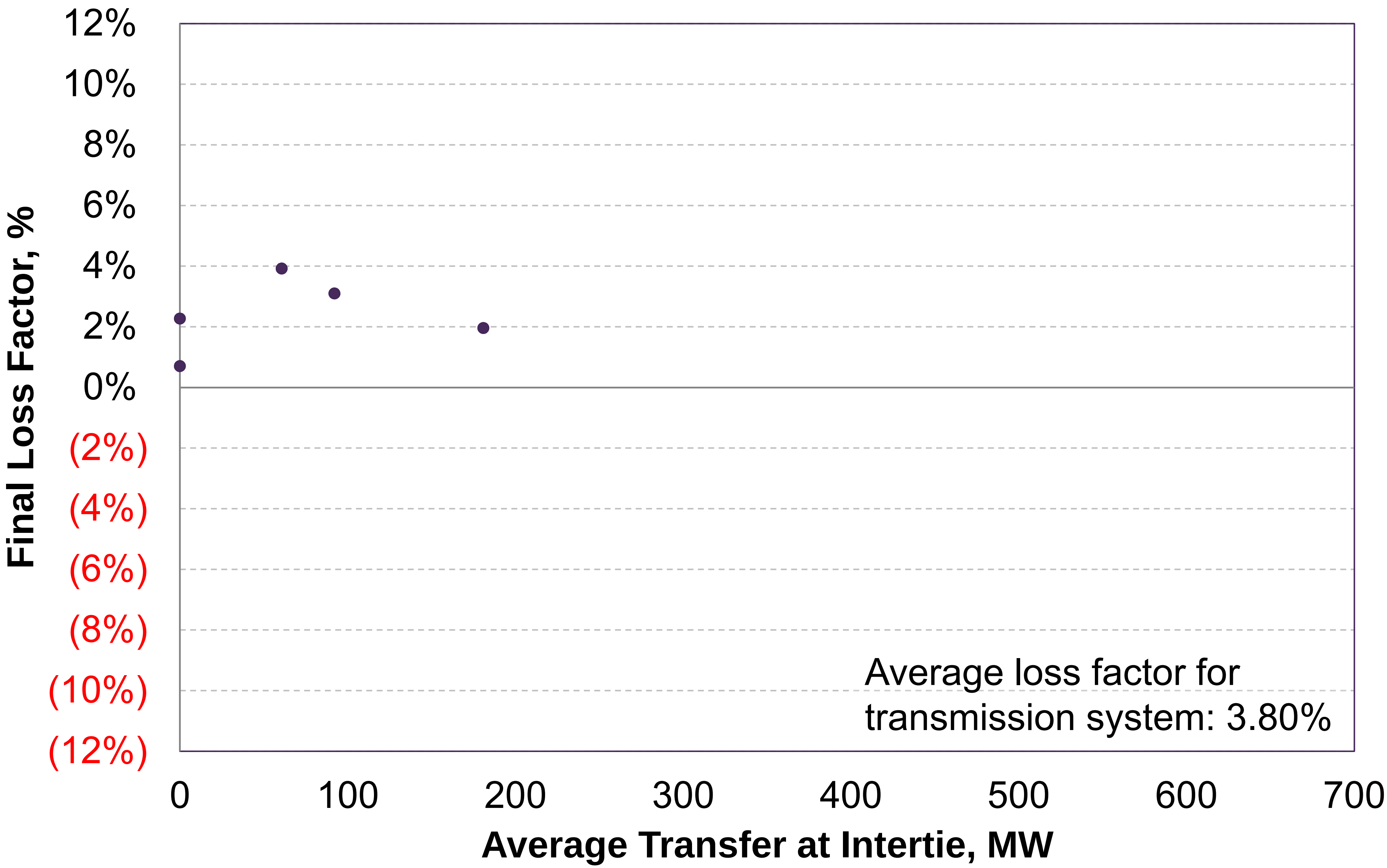
Biomass and other generating facilities show more dispersion in loss factors



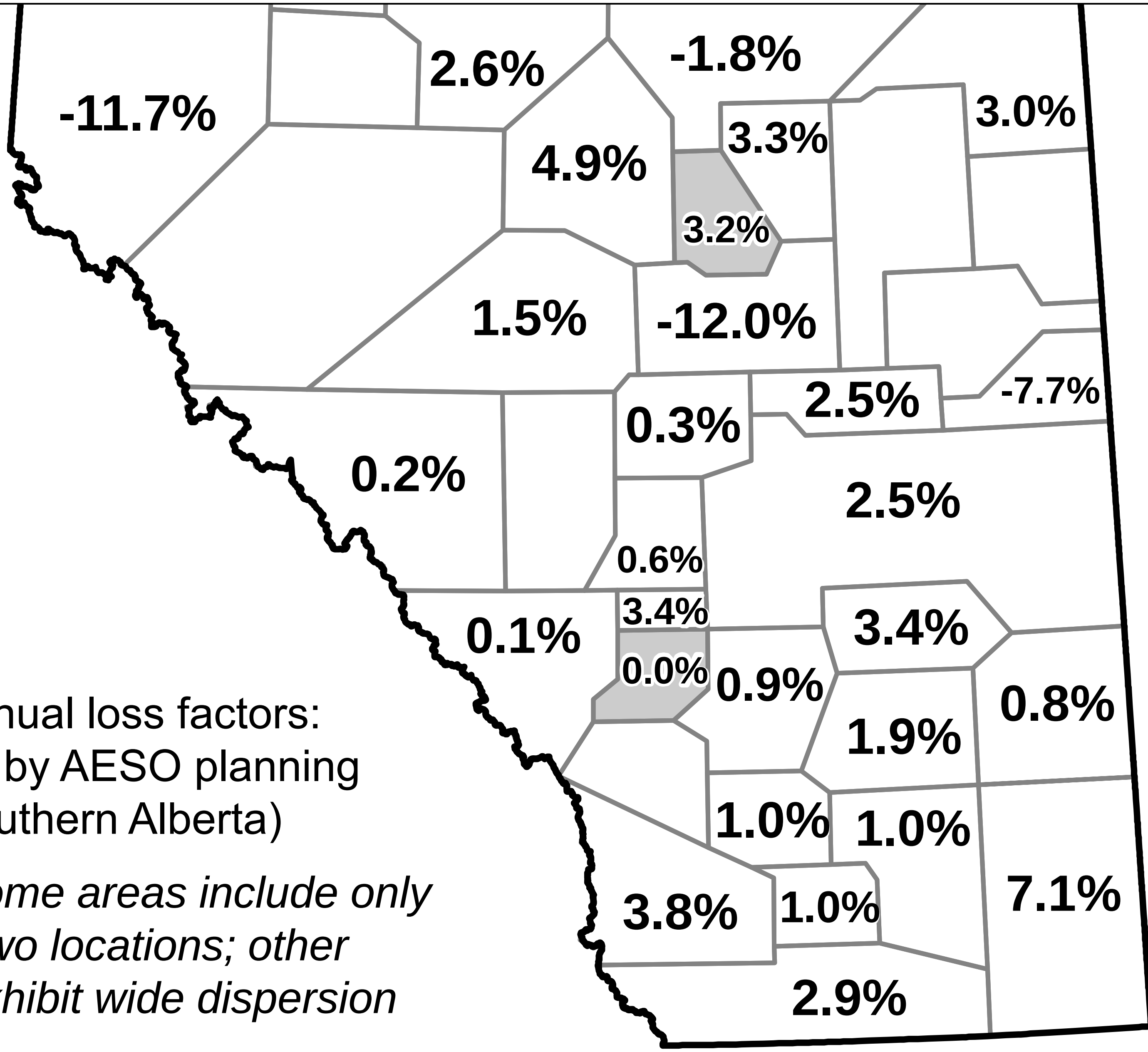
Reversing distribution points of delivery show more dispersion in loss factors



Interties show less dispersion in loss factors



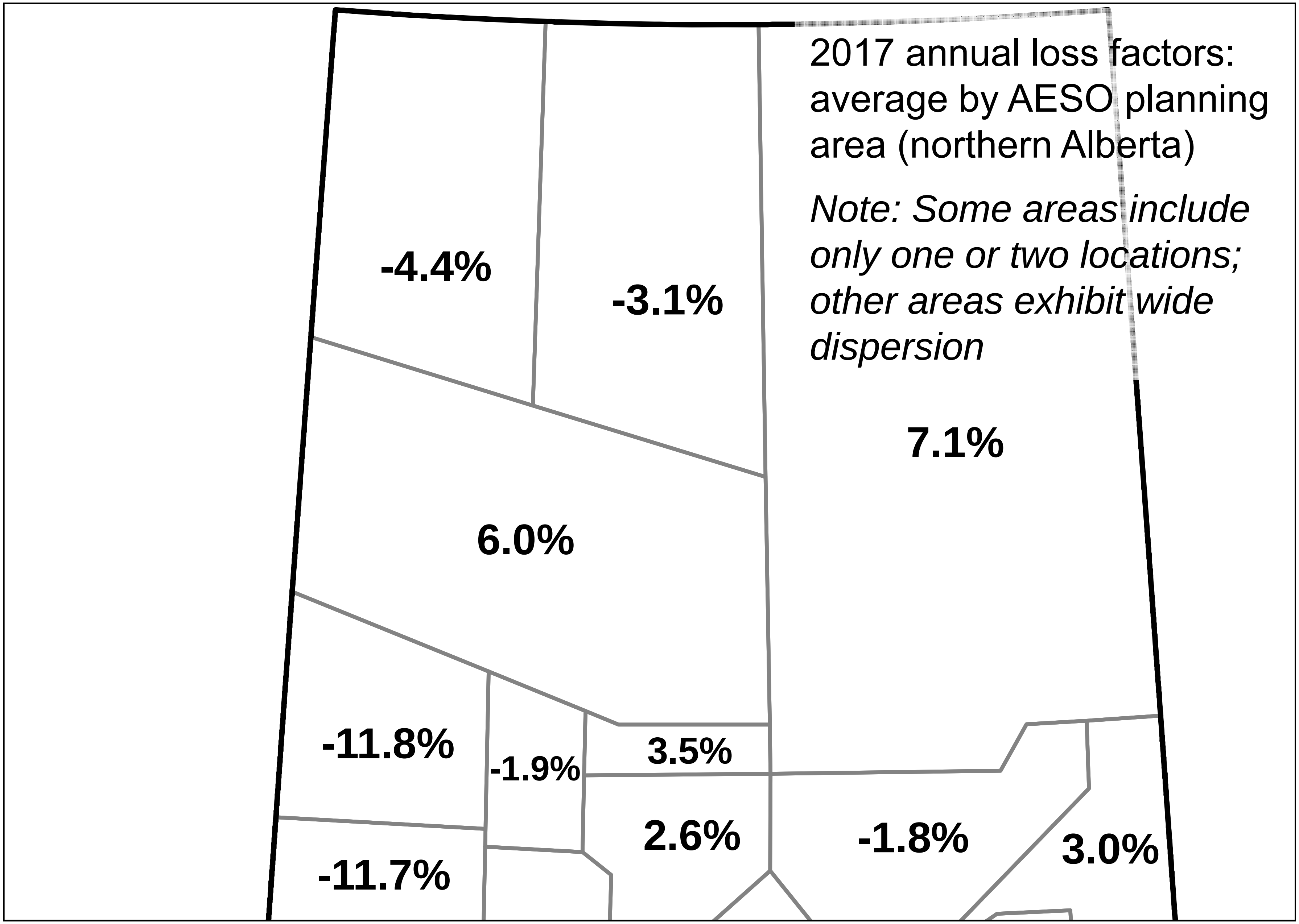
Annual loss factors tend to be positive (charges) in southern Alberta



2017 annual loss factors: average by AESO planning area (southern Alberta)

Note: Some areas include only one or two locations; other areas exhibit wide dispersion

Annual loss factors tend to be negative (credits) in northwest Alberta



2017 loss factors are calculated using an incremental loss factor methodology

- Incremental methodology calculates hourly raw loss factors with merit order redispatch
  - First, transmission system losses are calculated using the historical volume for a pool asset in an hour
  - Second, transmission system losses are calculated after removing the pool asset's volume and replacing it by redispatching other assets (regardless of location) up the historical merit order for the hour
  - Third, the hourly raw loss factor is calculated as the difference between system losses calculated in the initial and redispatched states, divided by the pool asset's volume in the hour
- Hourly shift factors are used to ensure loss factors recover transmission system losses in each hour
- Legislation requires loss factor compression to within ±12%

“Procedure” document describes automated process used to calculate losses

- System topologies are first adjusted
  - To accommodate specific locations identified in Loss Factor Rule
    - Industrial systems, distribution-connected generation, Medicine Hat, power purchase arrangements, and Bow River hydro plants
  - To exclude facilities owned and operated by market participants
- Generation and load data are added to the system topology
  - If data is missing, hour is excluded for all locations
- Solution parameters are initialized in PSS/E power system simulation software

“Procedure” document describes automated process used to calculate losses (cont’d)

- System is solved for initial state
  - Flows on WATL and EATL HVDC lines are adjusted to minimize losses
  - Incremental changes to PSS/E settings are implemented to reach common final solution state
    - Full Newton-Raphson method, shunt adjustments enabled
  - Marginal source asset is dispatched up or down merit order to balance load plus system losses
  - System losses are recorded and solution is saved
    - If system cannot solve, hour is excluded for all locations
    - Failure to solve usually occurs if solution does not converge (sometimes during HVDC optimization) and occasionally if solution converges but does not reach flow tolerance

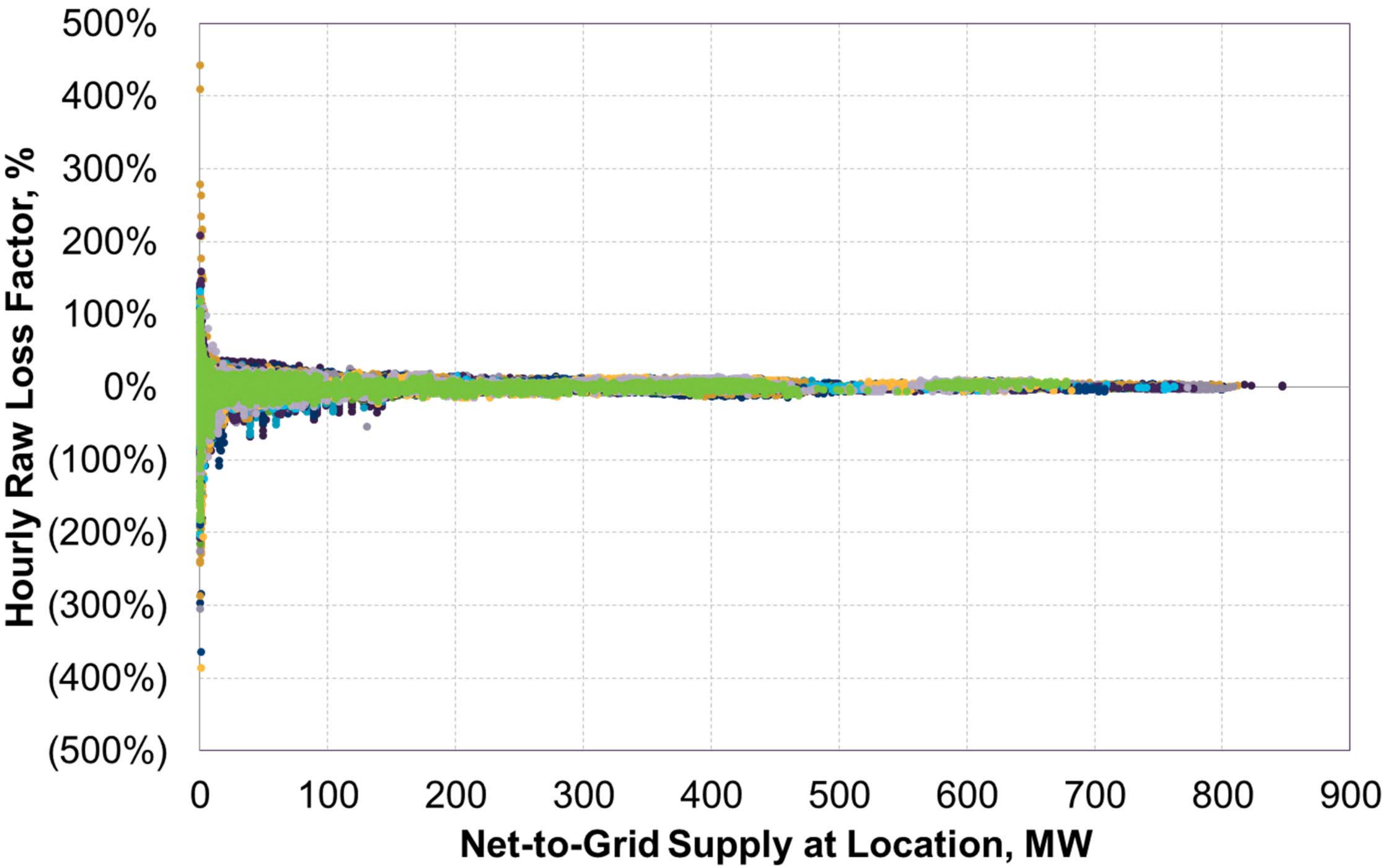
"Procedure" document describes automated process used to calculate losses (cont'd)

- System is solved for redispatched state for each location
  - If no dispatch or dispatch is less than 1.00 MW at location, hour is excluded for location
- – Net-to-grid dispatch of generating facility is reduced to 0 MW
- – Marginal source asset is dispatched up or down merit order to balance load plus system losses
- – Flows on WATL and EATL HVDC lines are reset to original values then adjusted to minimize losses
- – Incremental changes to PSS/E settings are implemented to reach common final solution state
- – System losses are recorded and solution is saved
  - If system cannot solve, hour is excluded for location

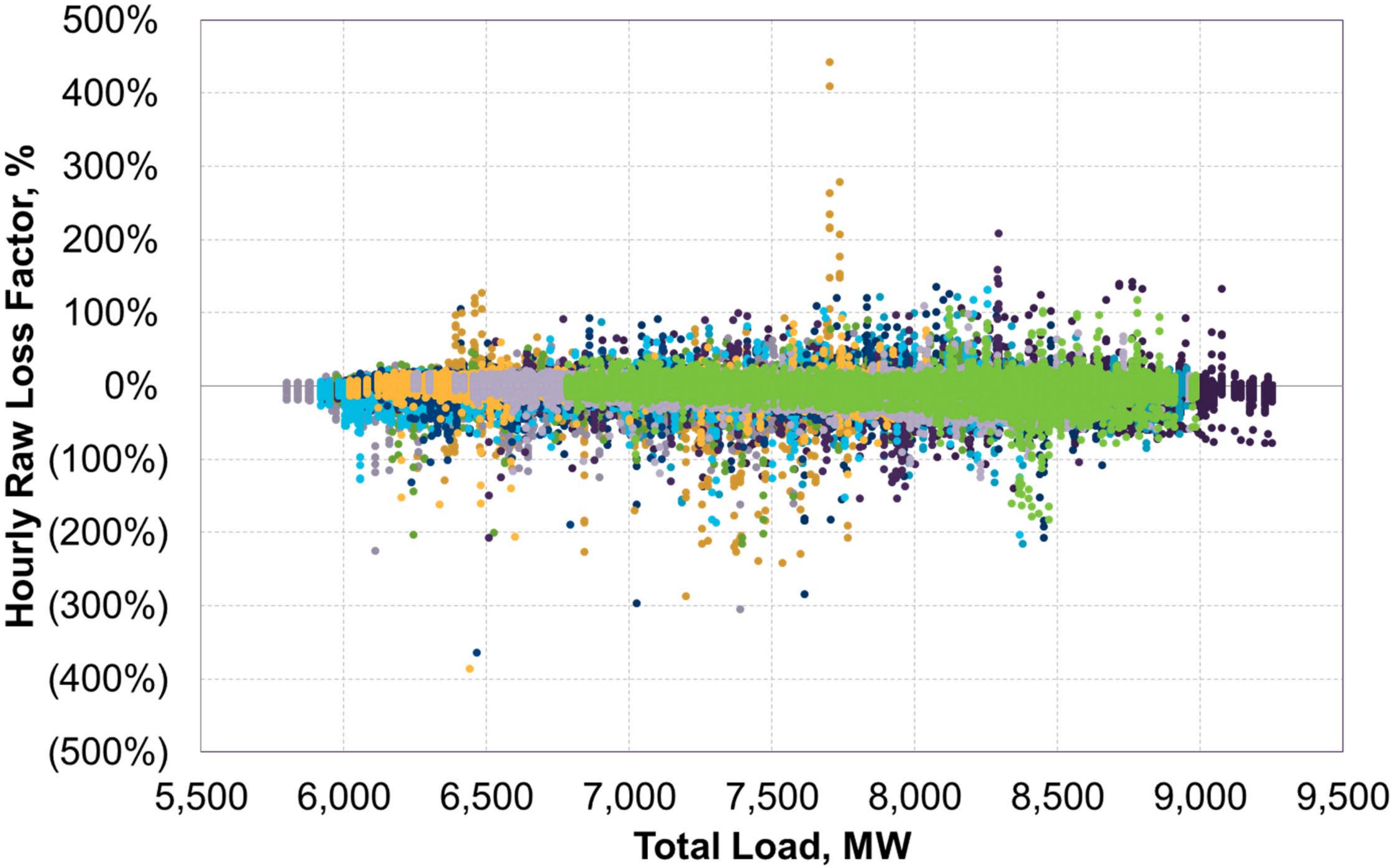
Loss factor determination attempts up to over 1.1 million PSS/E solutions

- Automated process attempts to create 8,760 solved cases for initial state
- Automated process attempts to create up to 1,165,080 solved cases for redispatched state
- Solution calculations take about two days running concurrently on five computers (with multiple instances of PSS/E on each computer)

Hourly raw loss factors show greater dispersion for smaller net-to-grid volumes



Hourly raw loss factors are dispersed over all total load levels



About 55% of all hours and locations had dispatch and data for loss factor calculations

Hours (×133)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Total hours	98,952	89,376	98,819	95,760	98,952	95,760	98,952	98,952	95,760	98,952	95,893	98,952	1,165,080
No dispatch	(36,155)	(33,847)	(38,649)	(38,486)	(38,145)	(32,038)	(34,621)	(40,937)	(47,867)	(50,799)	(43,722)	(43,277)	(478,543)
Missing data	(7,634)	(6,919)	(6,350)	(5,168)	(5,632)	(5,112)	(3,300)	(2,960)	(1,420)	(1,452)	(707)	0	(46,654)
Potential hours	55,163	48,610	53,820	52,106	55,175	58,610	61,031	55,055	46,473	46,701	51,464	55,675	639,883

Percentages	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Total hours	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
No dispatch	(37%)	(38%)	(39%)	(40%)	(39%)	(33%)	(35%)	(41%)	(50%)	(51%)	(46%)	(44%)	(41%)
Missing data	(8%)	(8%)	(6%)	(5%)	(6%)	(5%)	(3%)	(3%)	(1%)	(1%)	(1%)	0%	(4%)
Potential hours	56%	54%	54%	54%	56%	61%	62%	56%	49%	47%	54%	56%	55%

About 90% of all potential hours and locations successfully solved

Hours (×133)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Potential hours	55,163	48,610	53,820	52,106	55,175	58,610	61,031	55,055	46,473	46,701	51,464	55,675	639,883
Unsolved initial	(6,650)	(5,719)	(5,054)	(9,842)	(5,320)	(10,773)	(11,172)	(532)	(1,330)	(2,394)	(1,862)	(1,330)	(61,978)
Unsolved redispatched	(50)	(251)	(174)	(115)	(495)	(26)	(151)	(29)	(36)	(30)	(37)	(68)	(1,462)
Solved hours	48,463	42,640	48,592	42,149	49,360	47,811	49,708	54,494	45,107	44,277	49,565	54,277	576,443

Percentages	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Potential hours	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Unsolved initial	(12%)	(12%)	(9%)	(19%)	(10%)	(18%)	(18%)	(1%)	(3%)	(5%)	(4%)	(2%)	(10%)
Unsolved redispatched	(0%)	(1%)	(0%)	(0%)	(1%)	(0%)	(0%)	(0%)	(0%)	(0%)	(0%)	(0%)	(0%)
Solved hours	88%	88%	90%	81%	89%	82%	81%	99%	97%	95%	96%	97%	90%

Reasons for exclusion of hours are indicated by codes in workbook

- Hours excluded from calculations for all locations
  - Missing or unavailable historic data (XA-MISSIN): 0 hours
  - Insufficient source assets to balance system in initial state (XA-INSUF1): 0 hours
  - Insufficient source assets to balance system in redispatched state (XA-ISUF2): 0 hours
- Hours excluded from calculations for single locations
  - No dispatch or volume <1.00 MW (XS-NODISP): 478,543 hours
  - Missing or unavailable data (XS-MISSIN): 46,654 hours
    - Due to asset not yet in service during year
  - Cannot solve losses in initial state (XS-UNSOL1): 61,978 hours
  - Cannot solve losses in redispatched state (XS-UNSOL2): 1,462 hours

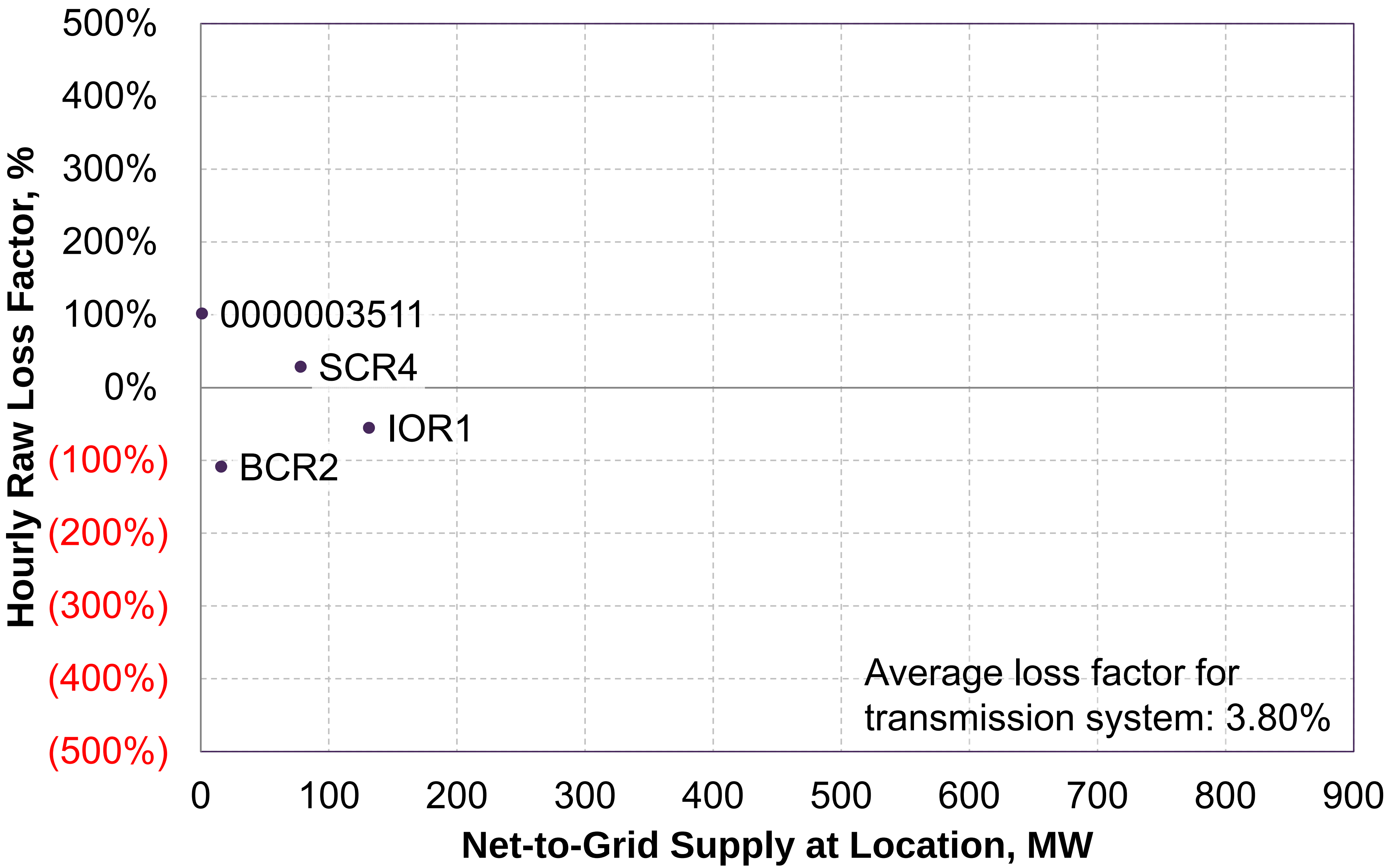
Very few hours were excluded for redispatched state at most locations

- Some locations had very few hours with dispatch greater than 1.00 MW
  - Including some distribution points of delivery with distribution-connected generation
  - Six locations had fewer than 100 hours with dispatch greater than 1.00 MW
- Losses solved in redispatched state for more than 99.5% of hours at123 out of 133 locations (92% of all locations)

Dispersion of raw loss factors appears to be affected by several factors

- Location of generating facility on transmission system
  - Strong or weak transmission system in area
  - Whether area is net load (importing) or net generation (exporting)
- Location of next-in-merit generating facility or facilities in specific hours of dispatch (used as swing bus)
- Size of volume increase of generating facility
- Dispatch level of WATL and EATL HVDC lines in initial and redispatched states
- Magnitude of differences from original topology case
  - Can result in voltage variations
- Resolution limits of PSS/E simulation and numerical solution (usually for small dispatch volumes)

Calculation of loss for four specific cases illustrate steps of procedure



0000003511 reversing POD (Seebe)
21 Dec 2017 15:00: loss factor 101.72%

Procedure Step	Net-to-Grid Supply (MW)	System Losses (MW)	Marginal Location (MPID)	Marginal Supply (MW)
Original topology	1.0	363.4	SD4 – 2	238.5
Initial state	1.0	329.7	SD4 – 2	204.8
Redispatched state	0.0	328.7	SD4 – 2	204.9
Decrease (increase)	1.0	1.0		

- Hourly raw loss factor: 1.0 MW ÷ 1.0 MW = 101.72%
- Redispatched state reflects decrease in supply in Seebe and increase in supply in Lake Wabamun
  – Approaching resolution limits of simulation

SCR4 Wintering Hills (Sheerness)
9 Jan 2017 09:00: loss factor 28.54%

Procedure Step	Net-to-Grid Supply (MW)	System Losses (MW)	Marginal Location (MPID)	Marginal Supply (MW)
Original topology	78.0	394.8	RB5 – 1	39.6
Initial state	78.0	381.5	SD1 – 3	268.2
Redispatched state	0.0	359.2	RB5 – 1	81.9
Decrease (increase)	78.0	22.2		

- Hourly raw loss factor: 22.2 MW ÷ 78.0 MW = 28.54%
- Redispatched state reflects decrease in supply in Sheerness and increase in supply in Rainbow Lake
  - Losses decrease in central east due to removal of supply
  - Losses also decrease in northwest due to decreased flow from other regions

IOR1 IOR Cold Lake (Cold Lake)
31 May 2017 13:00: loss factor (55.24%)

Procedure Step	Net-to-Grid Supply (MW)	System Losses (MW)	Marginal Location (MPID)	Marginal Supply (MW)
Original topology	131.3	225.1	SD3 – 3	310.0
Initial state	131.3	211.9	SD3 – 2	296.9
Redispatched state	0.0	284.5	SH2 – 1	173.0
Decrease (increase)	131.3	(72.5)		

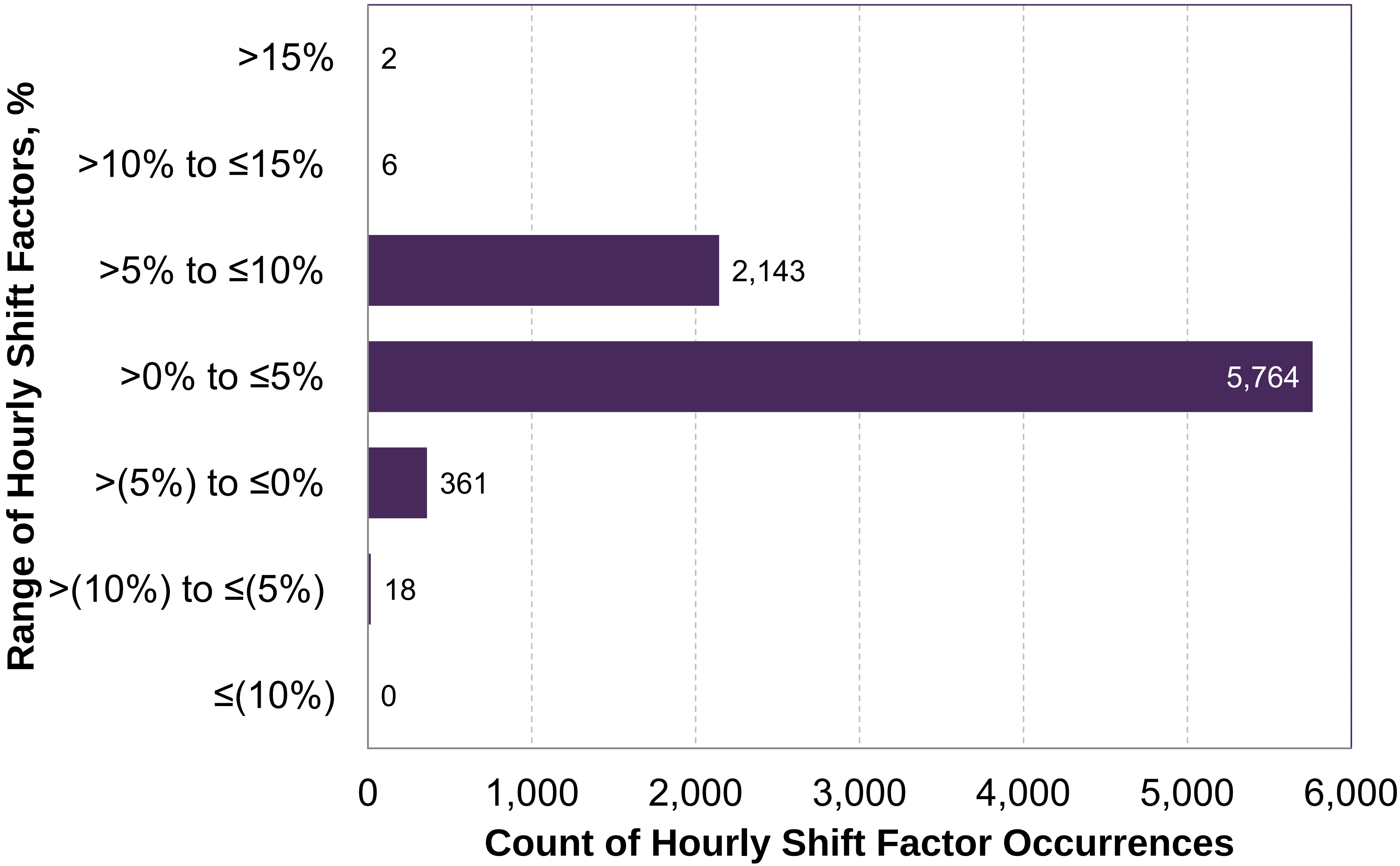
- Hourly raw loss factor: (72.5 MW) ÷ 131.3 MW = (55.24%)
- Redispatched state reflects decrease in supply in Cold Lake and increase in supply in Lake Wabamun and Sheerness
  - Losses expected to increase due to removal of supply in Cold Lake
  - However, large increase may result from an unstable PSS/E solution

BCR2 Bear Creek (Grande Prairie) 2 Mar 2017 19:00: loss factor (108.67%)

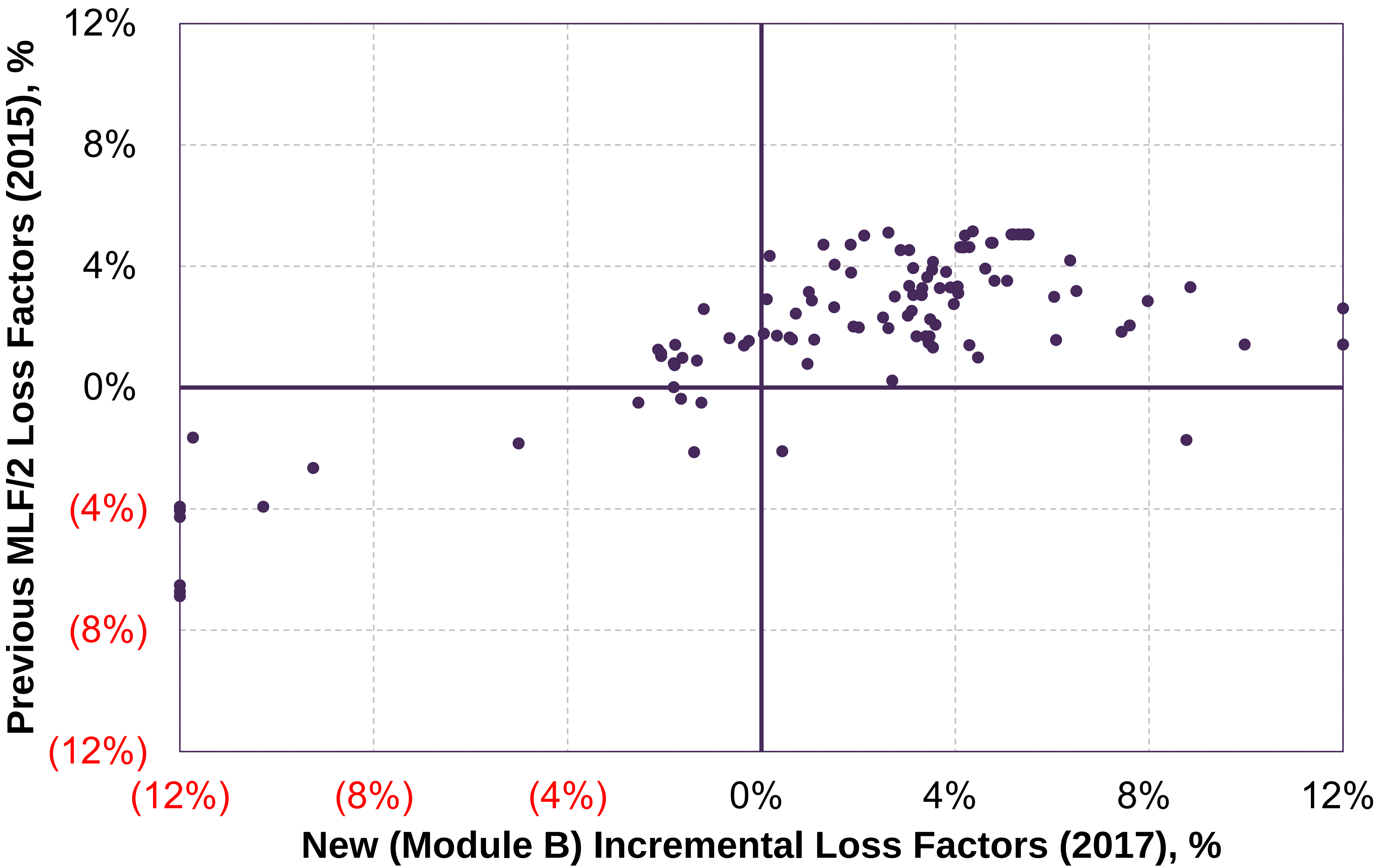
Procedure Step	Net-to-Grid Supply (MW)	System Losses (MW)	Marginal Location (MPID)	Marginal Supply (MW)
Original topology	15.9	405.0	CRS1 – 1	42.5
Initial state	15.9	391.3	CRS1 – 1	28.8
Redispatched state	0.0	408.6	SD5 – 5	371.5
Decrease (increase)	15.9	(17.3)		

- Hourly raw loss factor: (17.3 MW) ÷ 15.9 MW = (108.67%)
- Redispatched state reflects decrease in supply in Grande Prairie and increase in supply in Airdrie and Lake Wabamun
  - Losses increase in northwest due to removal of supply
  - Losses also increase in northeast due to increased flow from Fort McMurray to northwest

Almost all hourly shift factors were in range of (5%) to 10%

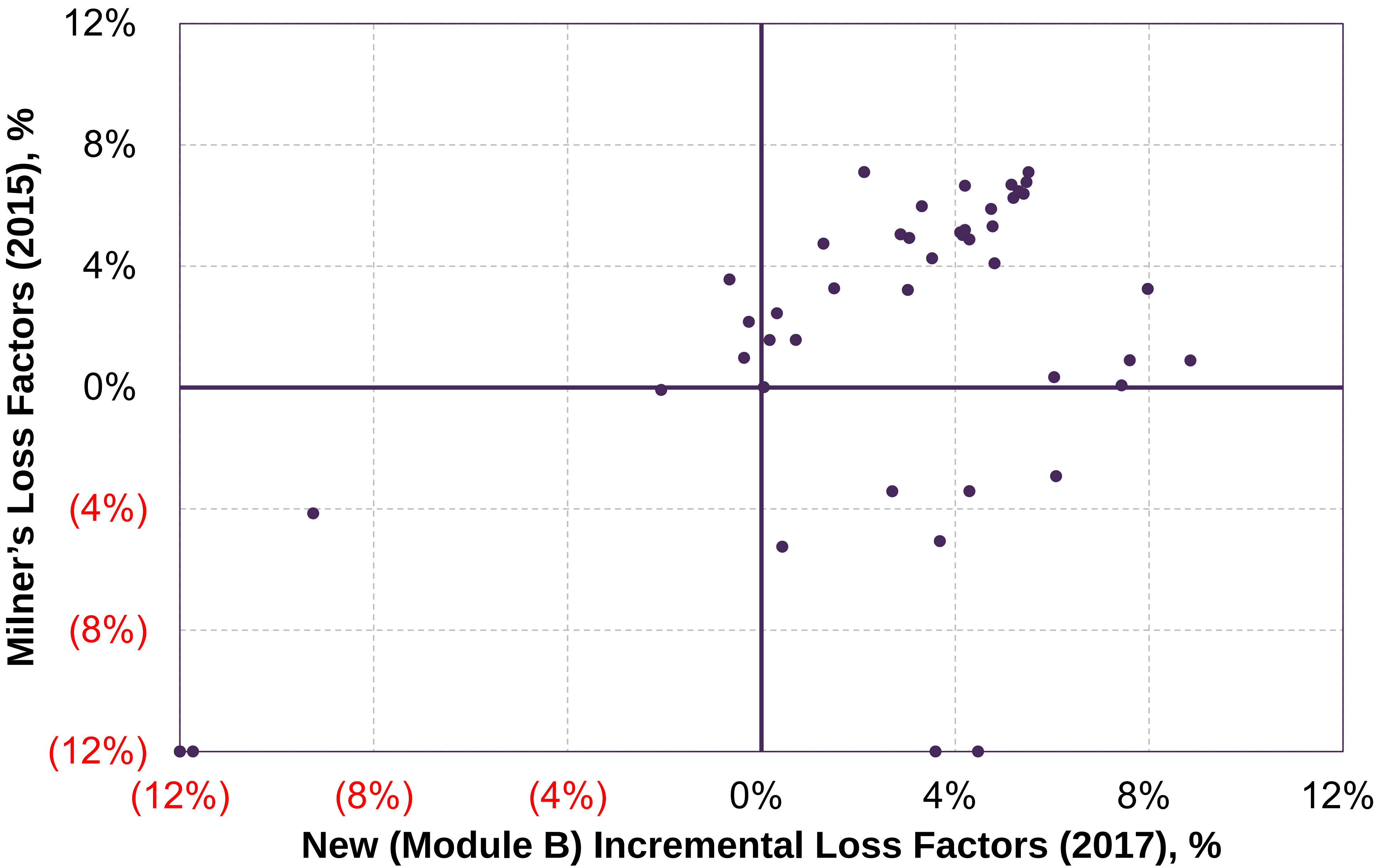


Module B loss factors have greater dispersion than previous loss factors



Module B results differ from “Old AESO” (incremental with load scaling) loss factors

Module B results also differ from Milner's proposed "generation vector" loss factors



AESO will next be focusing on 2018 loss factors and Module C calculations

- Over next few months, AESO will complete Module B work for 2018
  - Jun 2017: Develop process for preliminary loss factors
  - Jul-Sep 2017: Prepare 2018 loss factors
- Following Module C methodology decision, AESO will transition to Module C work
  - Oct 2017 to 2018: Module C loss factors
- Preparation of historical merit orders for 2006-2016 has been initiated
  - Greatest probability of being needed and potentially most time-consuming to prepare

Questions and discussion

- Loss factor information is posted on AESO website at www.aeso.ca
  - Grid ► Loss factors ► 2017 loss factors
  - Grid ► Loss factors ► 2017 loss factor development
- Additional questions can be directed to

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