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To: NEPOOL Markets Committee

From: Ben Griffiths, LS Power

Subject: Gas-Only Resource Availability Modeling & Possible Integration into ISO-NE's RCA Project
Working Draft – May be revised based on stakeholder feedback

1) Summary

ISO-NE's Resource Capacity Accreditation (RCA) project has the potential to improve capacity market price signals and system reliability. One change that ISO-NE is contemplating relates to pipeline gas availability during the winter season. This memo is comprised of two parts. The first part describes and applies a new methodology for quantifying gas availability on a regional-, state-, and unit-specific basis. The second part shows how those unit-specific results could be integrated into the RCA project to better quantify gas availability within GE MARS and the resulting MRI-based qualified capacity values.

Concerning gas availability, our analysis infers the presence and magnitude of gas-supply constraints by comparing *expected* generation for gas-only electric generators within the ISO New England Control Area with *observed* generation from these same resources. This allows us to elucidate relative gas availability as a function of ambient temperatures, especially at the coldest observed temperatures. The analysis offers a glimpse into how the interstate gas pipeline topology and gas economics intersect within ISO New England.

Looking across 36 gas-only generators, we find that units in Connecticut – i.e., generators interconnected into the Algonquin system (AGT) upstream of the Burrillville compressor station and generators interconnected into the Iroquois system – produce approximately the amount of power we would expect on cold days, while resources elsewhere in the region generate significantly *less* than expected. Moreover, generators downstream on the interstate pipelines and interconnected on certain highly constrained laterals demonstrate the worst cold weather performance. This indicates that the ISO New England gas-only fleet is not homogenous with respect to gas availability. At extreme cold temperatures, certain interconnection points demonstrate significantly degraded cold weather performance while resources in Connecticut have been able to obtain gas far more readily. A case study looking at physical flows on the Algonquin G-lateral triangulates results for units on that line.

Concerning RCA integration, we propose two different approaches that leverage the same gas availability methodology. The first approach would be to generate hourly "availability" profiles individual gas-only resources, conditioned on temperature. This unit-specific approach would have the aggregate effect of derating the entire fleet gas-only resources by 27% at extreme cold temperatures and by lesser magnitudes in cool-but-not-cold conditions. This approach would align with the proposed treatment of renewable resources and could reflect both the weather dependence and location dependence of gas availability in New England. The second approach would allocate aggregate gas availability, as identified in the ISO's conceptual framework, to specific units based on their observed cold-weather performance.

2) Pipeline Gas Availability

New England suffers from a tight gas market during the winter and a tight gas market implies a tight interstate pipeline gas system. In practice, at least some portions of the gas system are "constrained" during cold winter days, meaning that physical limits on the system will restrict otherwise desired gas use. In the summer, by contrast, aggregate demand for gas is much lower and the system is "unconstrained" – there is much more gas capacity than there is need for it. Gas system constraints can affect what units are dispatched for energy and the price of that energy. Accordingly, gas system constraints should also be implicitly embedded within the observed output profiles of gas-only generators. Thus, gas system constraints may be inferred through this power market data.

In this analysis, we infer the presence and magnitude of gas-supply constraints by comparing observed gas generation over the period December 2014 through March 2022 with counterfactual estimated generation from these same units, assuming that gas constraints were not present in New England.[1] The difference between expected generation and observed generation can be attributed to fuel limitations.

The economic framework of this model controls for fuel costs and other unit characteristics. Differences in aggregate generation cannot necessarily explain fuel availability – it might merely highlight operational characteristics. For example, higher heat-rate unit should run less often than lower heat-rate units due to economics alone. Similarly, if a significant amount of oil generation is in merit due to a "price inversion", then we cannot necessarily attribute a lack of gas generation to fuel unavailability – it might merely highlight out-of-merit offers on a given day. Finally, the model's focus on *output* rather than *availability* provides an objective benchmark of unit performance.

While our approach may sound novel, its concept is anything but. The ISO has longstanding experience assessing how system constraints affect generation. In the Economic Studies, the ISO can change physical constraints to observe how those constraints affects generation and prices. For example, as part of the 2019 Economic Study cycle, the ISO evaluated the effectiveness of transmission upgrades to Orrington South to increase production from constrained onshore renewables in Maine.[2] The ISO conducted similar analysis in 2015 exploring the benefits of increasing the interface limit at Keene Road.[3] In this analysis, we rely on the same concept but invert the process. Instead of changing interface constraints to observe prices and generation quantity, here we change prices to observe changes in generation and, implicitly, the constraints themselves.

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[1] The eight-year study period was selected to cover a wide range of stressed operational conditions. This look-back period was selected to align with the introduction of EMOF. Since then, the Algonquin Incremental Market project went into service in 2016, providing an additional 342 million cubic feet per day (MMcf/d) of pipeline capacity to the New England market, and the ISO-NE Pay-for-Performance went effect on June 1, 2018. Both changes would have further enhanced winter system operations.

[2] https://www.iso-ne.com/static-assets/documents/2020/10/2019-renew-es-report-final.docx

[3] https://www.iso-ne.com/static-assets/documents/2016/09/2015_economic_study_keene_road_increased_export_limits_fina.docx

2.1) Observed Generation

Observed generation for gas-fired electric generators is sourced from the EPA's public CEMS database.[4] The EPA database provides *hourly* generation for all relevant gas-only resources in a standard format. The observed generation data in CEMS intrinsically embeds unit-specific operating constraints and pipeline fuel constraints.

Observed generation is transformed to a binary variable: 1 if the resource had output above zero, 0 otherwise. In effect, this transformation assumes that the resource was running entirely or not at all and simplifies issues around ramping, partial dispatch, and the like.

2.2) Expected Generation

Expected generation is computed using profit-maximizing dispatch model and accounts for a prevailing market conditions as well as unit specific operating characteristics such as start-up costs, minimum run-times, and minimum down-times (Equation 1).

$$\max \sum_{t=0}^{T} Q_t \times \left(LMP_t - C_{Run,t}\right) - \; SU_t \times C_{SU} \tag{1}$$

where **t** is an indexed hourly value, **Q** is the hourly dispatch quantity decision variable**, LMP** is the market's hourly electricity price, $\mathbf{C_{run}}$ is the unit's hourly cost, **SU** is the start-up tracking variable and $\mathbf{C_{SU}}$ is the unit's start-up cost.

The cost to run a unit in a given hour ($C_{Run,t}$) depends on many factors, as depicted in Equation 2. The model is parametrized using unit-specific information where possible, but supplement with information developed by Concentric Energy Advisors in their 2020 CONE reset process.

$$C_{Run,t} = HR \times \left[\left(C_{Gas,d} \times CT\ Tax\right) + Basis + C_{RGGI,d} + C_{MA\ CO2,d}\right] + VOM \tag{2}$$

Where,

LMP_t	is the day-ahead LMP at the internal hub ($/MWh)
HR	is a unit's observed annual heat rate using data from EIA Form 923 for calendar year 2021 (MMBtu/MWh).[5]
$C_{Gas,d}$	is the daily index price of gas at Algonquin City Gate ($/MMBtu).
$C_{RGGI,d}$	is the daily price of RGGI (restated in $/MMBtu) based on linear interpolation between RGGI auctions.[6]
$C_{MA\ CO2,d}$	is the daily price of Massachusetts 310 CMR 7.74 supplemental carbon price (restated as $/MMBtu) based on annual average auction price, and is only applied to units in Massachusetts.
$Basis$	is a cost of transporting gas from the citygate to a power plant. Basis is empirically estimated for each unit using an optimization approach ($/MMBtu).[7]

[4] https://campd.epa.gov/
[5] https://www.eia.gov/electricity/data/eia923/ Schedules 3A & 5A.
[6] https://www.rggi.org/auctions/auction-results/prices-volumes
[7] Basis must be inferred because true transportation costs are commercially sensitive information, which is not publically available. The optimization minimizes the difference between estimated and observed generation for

$CT\ Tax$ is a 1.05 gas-price multiplier for resources in Connecticut, which imposes a 5% gross earnings tax on gas sales.[8]

VOM is the estimated variable O&M costs by unit. Based on the Concentric CONE analysis we assume VOM = \$3.6/MWh for a CC and \$1.16/MWh for a GT.[9]

C_{SU} is the start-up cost for each unit. Based on the Concentric CONE study, we assume C_{SU} of \$29.65/MW for a CC and \$31.58/MW for a GT.[10]

The fuel cost and basis terms are particularly consequential to this analysis. Together they impose the heart of the counterfactual premise that resources can buy timely gas at the Citygate price, plus a fixed "summer" basis. In this way, expected generation assumes that gas system is *unconstrained* for purposes of offer formulation year-round.

For the most part, the model will dispatch a resource when its offer is *below* the region's prevailing LMP – i.e., Internal Hub – and not dispatch a resource when its offer is *above* LMP. Due to start-up costs and intertemporal constraints, however, there are some hours when profit-maximizing dispatch nevertheless has a resource run at a loss.

To this basic offer structure, there are three additional complications related to Wallingford – the only gas-only resource which is not also a combined cycle (see Table 1, below). Wallingford is comprised of seven fast-start combustion turbines which routinely participate in the FRM and which procure gas in the intra-day market rather than the timely cycle due to a lack of day-ahead commitment.

1) Wallingford's cost of gas ($\boldsymbol{C_{Gas,d}}$) is assumed to be elevated compared to the citygate index price, according to the intraday gas premiums identified in the 2020 CONE analysis.[11]
2) Wallingford's heatrate depends, on an hourly basis, on whether a given unit is participating in the FRM. Historic FRM participation, on an hourly, per-unit basis was identified from unit-specific MIS files. In hours when a unit was participating in the FRM, the $\boldsymbol{HR}$ is set to 22 MMBTU/MWh instead of its actual winter heatrate of 10.6. The FRM Heat Rate is designed to have participating resources generate electricity in less than 2.5% of hours.
3) For the hours when Wallingford is participating as an FRM resource, the reference market price (LMP_t), is the real-time LMP at the internal hub due to FRM rules.

Figure 1 depicts key prices in the study period and Table 1 depicts the key offer inputs for each assessed resource. We rely on the same resource offer parameterization for each unit at a given facility. We acknowledge that there are many simplifications in this analysis but because each of these units is a combined cycle, Wallingford excepted, omissions and simplifications should affect each resource in a

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temperatures above 50 Degrees F. Due to time limitations, we accept basis estimates that yield estimated generation within 3% of observed generation.

[8] *See* Concentric's CONE analysis at 66. https://www.iso-ne.com/static-assets/documents/2020/12/updates_cone_net_cone_cap_perf_pay.pdf. Lake Road is exempted from this 5% cost. *See* https://www.cga.ct.gov/current/pub/chap_212.htm.

[9] CONE analysis at 39.

[10] CONE analysis at 66.

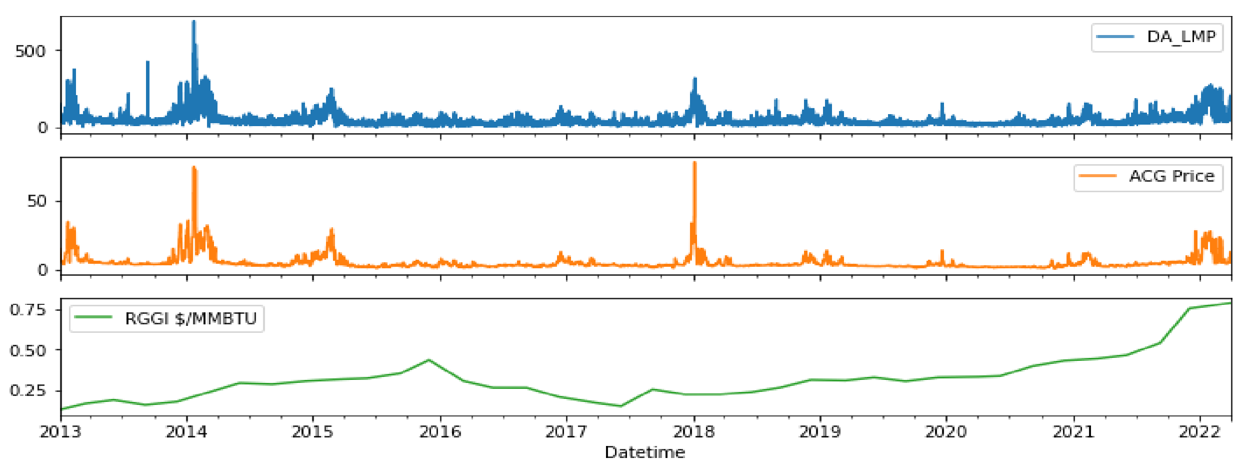
[11] CONE analysis at 67. Concentric found that intraday gas sold at a 4% premium to timely gas in the summer, 20% premium in the winter, and 11% in other months.

directionally similar way. ISO-NE could develop a more refined version of this analysis given its understanding of unit-specific offer parameters and bidding characteristics.

Table 1: Resource Characteristics and Offer Parameters

Facility Name	Gen Type	Load Zone	Gas System	Gas Turbine Make / Model[12]	Heat Rate	VOM	Citygate Basis ($)
Bellingham	CC	SEMA	AGT	ABB GT24	7.833	$3.60	-$0.46
Berkshire	CC	WCMA	TGP	ABB GT24	7.386	$3.60	$0.08
Blackstone	CC	SEMA	AGT	ABB GT24	7.759	$3.60	-$0.40
Bridgeport Energy	CC	CT	IRQ	Siemens V84.3A	7.103	$3.60	$0.04
Bridgeport Harbor 5	CC	CT	IRQ	GE 7HA.02	6.778	$3.60	-$0.06
Dighton	CC	SEMA	AGT-G	Alstom 11N2	8.119	$3.60	-$0.26
Footprint	CC	NEMA	AGT-I	GE 7F.05	7.929	$3.60	$0.39
Granite Ridge	CC	NH	TGP	Siemens 501G	7.427	$3.60	-$0.13
Lake Road	CC	CT	AGT	ABB GT24	7.409	$3.60	-$0.42
Maine Independence	CC	ME	M&NE	GE 7F	7.813	$3.60	$0.98
MASSPOWER	CC	WCMA	TGP	GE 7EA	8.535	$3.60	-$0.26
Milford (CT)	CC	CT	IRQ	ABB GT24	7.333	$3.60	-$0.26
Milford (MA)	CC	SEMA	AGT	Siemens 501-D5	8.819	$3.60	-$0.16
Millennium	CC	WCMA	TGP	Siemens 501G	7.303	$3.60	-$0.04
RISEP	CC	RI	TGP	Siemens 501FD2	7.185	$3.60	-$0.01
Rumford	CC	ME	PNGTS	GE 7F	7.779	$3.60	$0.75
Tiverton	CC	RI	AGT-G	GE 7F	7.115	$3.60	-$0.06
Wallingford	GT	CT	AGT-C	LM6000PC	10.603	$1.16	-$0.30
Westbrook	CC	ME	M&NE	GE 7F	7.293	$3.60	$0.36

Figure 1: Market prices by hour for the period Jan-2013 through Mar-2022.

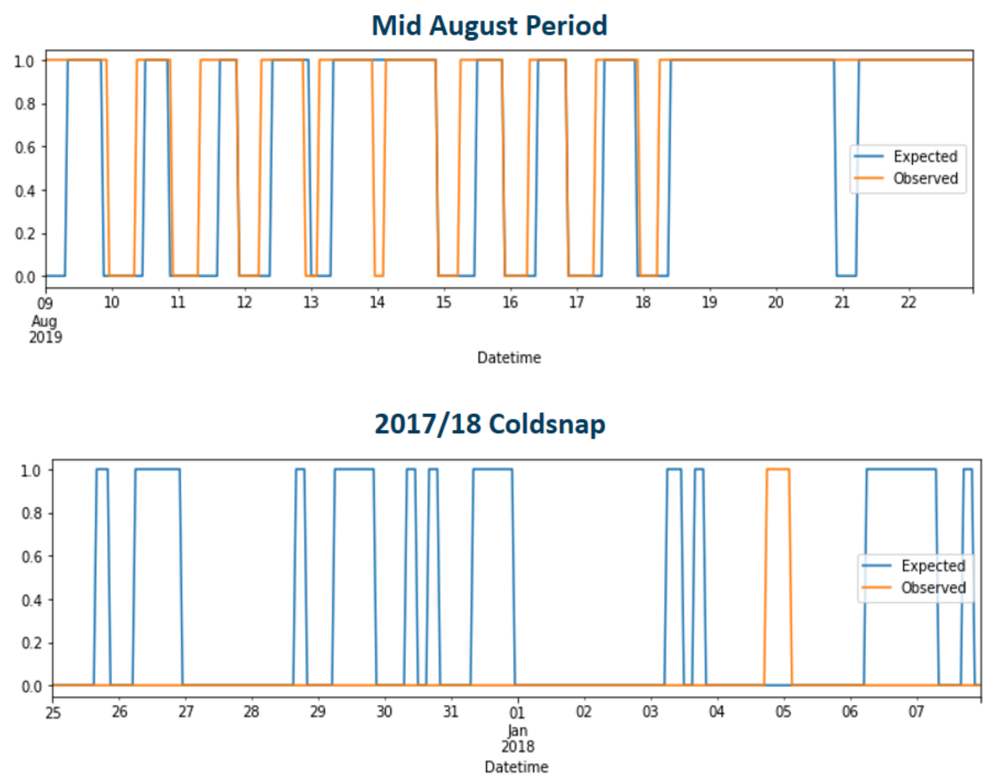


[12] Informational drawn from respective facilities' Title V Operating Permits except for the ME facilities, which was obtained from publicly available information available on the worldwide web.

2.3) Comparing Observed and Expected Generation

The unit parameters and profit-maximizing dispatch algorithm combine to yield hourly estimated generation profiles for each unit running from December 2014 through March 2022. With observed and expected generator output developed, it is possible to compare how we *expect* resources to perform versus how they actually did. Figure 2 depicts dispatch for [Unit C] over two different two-week periods, one summer and one winter. In each subplot, a value of 1.0 represents an hour when the unit was running while a value of 0.0 represents an hour when the unit was not running.

***Figure 2: Sample Dispatch for a Single Unit (August 2019 vs* 2017/18 Coldsnap)**



The upper subplot depicts a period when estimated generation tracks observed generation relatively well. In both cases, the unit exhibits a daily cycling pattern in the first 10 days and a more sustained run over the last 4 days. Unsurprisingly, the expected and observed generation do not perfectly match. There are instances where the model indicates the unit should have run, even though it did not in reality, and other instances where the unit ran in reality but the model indicates it should have remained offline. All told, in this two-week period, the model expected the unit to run 216 hours but the unit was observed to run 265 hours.

The lower subplot depicts a period when expected and observed generation deviate significantly. Over this two-week period, the unit ran just one time for a total of 9 hours while the model estimated it should run 11 times for a total of 104 hours. Comparing the expected and observed generation, we find that the unit ran just 8% as much as expected. The significantly depressed output suggests that the unit had difficulty procuring fuel during the cold-snap or that it could only obtain very high cost fuel.

What is true in particular is also true in general. With observed and expected generator output developed, it is possible to compare how we *expect* resources to perform versus how they actually did across the full set of study hours. Implied derates can be computed across a whole winter season but can also be computed in specific temperature ranges.

First, given the winter dimension of fuel stress, we can develop output probabilities, conditioned on temperature.[13]

$$P(Gen \mid Temp \leq Threshold) = \frac{Sum\ of\ Gen\ Hours\ with\ Temp\ below\ Threshold}{Count\ Hours\ with\ Temp\ below\ Threshold} \quad (3)$$

We use this same formula for both expected and observed generation. Finally, we compute relative deviations in output.

$$Derate = \frac{P(Observed\ Gen \mid Temp \leq Threshold)}{P(Expected\ Gen \mid Temp \leq Threshold)} - 1 = \frac{\sum Obseved\ Gen\ with\ Temps \leq Threshold}{\sum Expected\ Gen\ with\ Temps \leq Threshold} - 1 \quad (4)$$

This is equivalent to the fraction of hours, in a given temperature range, that a resource was observed running divided by the number of hours it was expected to run, less one. A negative value indicates that a resource is producing *less* energy than we would expect while a positive value indicates that a resource is producing *more* energy than we would expect.

For example, if a resource was observed to run for 100 hours at temperatures below 10 degrees, but expected to run for 400 hours, then the resulting deviation of -75% suggests that the resource either cannot obtain fuel, or can only obtain or very high basis fuels such as LNG, in the other 300 hours. For this reason, the deviation can be considered a metric of locational fuel (un)availability because it is estimating the proportion of time a resource can actually generate electricity at a given temperature due to fuel constraints.

2.4) Results

Table 2 offers results on a unit-specific, state-wide, and region-wide basis. Results in Table 2 are provided at five different temperature thresholds (less than or equal to 10 Degrees, between 10 and 20 Degrees, between 20 and 30 Degrees, between 30 and 40 Degrees, between 40 and 50 Degrees and temperatures above 50 Degrees). Due to the empirical basis adjustment calculation, all facilities have near zero deviation at temperatures above 50 Degrees. Results for each sub-section of Table is sorted based on expected unavailability at temperatures below 10 degrees. The region-wide and state-based totals are capacity-weighted averages.[14]

[13] Temperatures are sourced from the automated weather station at Bradley International Airport in Windsor Locks, CT – the same location the ISO used for its Inventoried Energy Program.

[14] When aggregating unit results into state- or region-wide values we set positive values to zero (like those for resources in Connecticut), because a resource cannot produce generation in excess of their capacity.

Table 2: ***Deviation (%) between Observed and Expected Generation.***

	T < 10	10 ≤ T < 20	20 ≤ T < 30	30 ≤ T < 40	40 ≤ T < 50	50 ≤ T
Total	-27%	-19%	-16%	-15%	-11%	-1%
State-Wide Results						
MA	-52%	-38%	-27%	-25%	-20%	-1%
ME	-41%	-32%	-29%	-33%	-19%	-1%
RI	-28%	-12%	-9%	0%	-1%	0%
NH	0%	-1%	-18%	-22%	-17%	0%
CT	0%	0%	0%	0%	0%	0%
Facility Specific Results						
[UNIT A]	-97%	-92%	-85%	-62%	-29%	-1%
[UNIT B]	-94%	-95%	-84%	-73%	-51%	0%
[UNIT C]	-89%	-75%	-73%	-49%	-23%	0%
[UNIT D]	-75%	-67%	-62%	-65%	-33%	0%
[UNIT E]	-65%	-46%	-42%	-49%	-32%	-3%
[UNIT F]	-51%	-37%	-44%	-34%	-23%	0%
[UNIT G]	-48%	-47%	-21%	-7%	-8%	-2%
[UNIT H]	-47%	-36%	-27%	0%	0%	-1%
[UNIT I]	-47%	-24%	0%	-9%	-20%	0%
[UNIT J]	-43%	-20%	-10%	-20%	-19%	-2%
[UNIT K]	-24%	-9%	-2%	-9%	-7%	0%
[UNIT L]	-18%	0%	0%	0%	-1%	0%
[UNIT M]	0%	-1%	-18%	-22%	-17%	0%
[UNIT N]	0%	0%	0%	0%	0%	0%
[UNIT O]	0%	0%	0%	0%	0%	0%
[UNIT P]	0%	0%	0%	0%	0%	0%
[UNIT Q]	0%	0%	0%	0%	0%	0%
[UNIT R]	0%	0%	0%	0%	0%	-1%
[UNIT S]	0%	-4%	0%	0%	0%	-2%

On a region-wide basis, we find that expected unavailability reaches 27% at the coldest temperatures. The assessed units have aggregate winter capacity of 9,080 MW so a 27% MW-weighted derate is equivalent to about 6,625 MW of available gas capacity at very cold temperatures (or a 2,455 MW reduction in gas availability).[15] This appears to align with various modeling exercises which indicate gas availability falls towards zero when 6,000 to 7,000 MW of gas generators are running.[16,17]

The 27% fleet-wide derate does not mean that every resource has a 1-in-3 chance of fuel unavailability at cold temperatures, or that all resources can consume 2/3rds of their full need in each hour. Some resources have much better gas availability than the fleet average and some much worse.

We find that every facility in Connecticut produces energy at a higher level that we would expect across a range of temperatures and that there is no appreciable temperature-dependent output deviation. ([UNIT S] exhibits a 4% underperformance between 10 and 20 degrees, but over-performance at all other temperatures.) Generators interconnected into the Algonquin system (AGT) upstream of the Burrillville compressor station and generators interconnected into the Iroquois system do not demonstrate reductions in output as temperatures fall. In practical terms, this suggests that the gas system is not constrained in Connecticut at any observed temperature.

Unlike Connecticut units, which have little temperature-dependent output deviation, units in other States appear to have less robust pipeline gas availability as temperatures fall (that is, expected and observed output in other states diverges as temperatures drop).

Units in Maine perform *worse* than units in Massachusetts at cool-but-not-cold temperatures and better than Massachusetts units at very cold temperatures. [UNIT D], [UNIT E], and [UNIT N] operate less than expected across a range of temperatures -- suggesting difficulty accessing pipeline gas across all temperatures. The former two units exhibit significant segregation at cold temperatures (75% and 65% less output than expected at cold temperatures) – [UNIT N] does not. [UNIT N]'s performance is slightly degraded and may possibly be explained by its winter fuel contracting arrangements. Excluding [UNIT N] from the Maine figures places it as worse-performing than Massachusetts – illustrating both the locational disadvantage compared to similar facilities in southern New England as well as the importance of fueling arrangements.

Resources in Massachusetts – connected to either Algonquin or TGP -- have wide variability in performance. Several units such as [UNIT A] (TGP) and [UNIT B] (AGT) have persistently poor cold-weather performance while others like [UNIT G], [UNIT J], [UNIT K], and [UNIT F] have increasingly poor performance as temperatures drop. The former units have significantly higher heat-rates than the latter – suggesting that their unavailability may relate to scarce gas molecules being consumed by generators that are more efficient; economic unavailability rather than physical undeliverability. Conversely, lower than expected output at very efficient units suggest that physical bottlenecks exist – why else would a very efficient unit like [UNIT F] be running less than expected?

The facilities on the AGT G lateral have large seasonal shifts in performance. This observation suggests these plants may have significant difficult obtaining gas in certain conditions. [UNIT H] has better availability than [UNIT C], perhaps because of its lower heat-rate or contracting arrangements of its parent Company. The facility on the AGT I lateral exhibits year-round poor performance. This degraded

[15] When aggregating unit results into state- or region-wide values we set positive values to zero (like those for resources in Connecticut), because a resource cannot produce generation in excess of their capacity.
[16] https://www.iso-ne.com/static-assets/documents/2021/12/2021-22-winter-outlook.pdf
[17] Patton, "Highlights of the 2021 Assessment of the ISO New England Markets" Slide 25 https://www.iso-ne.com/static-assets/documents/2022/06/npc-20220621-0623-composite4.pdf {PDF Page 178}

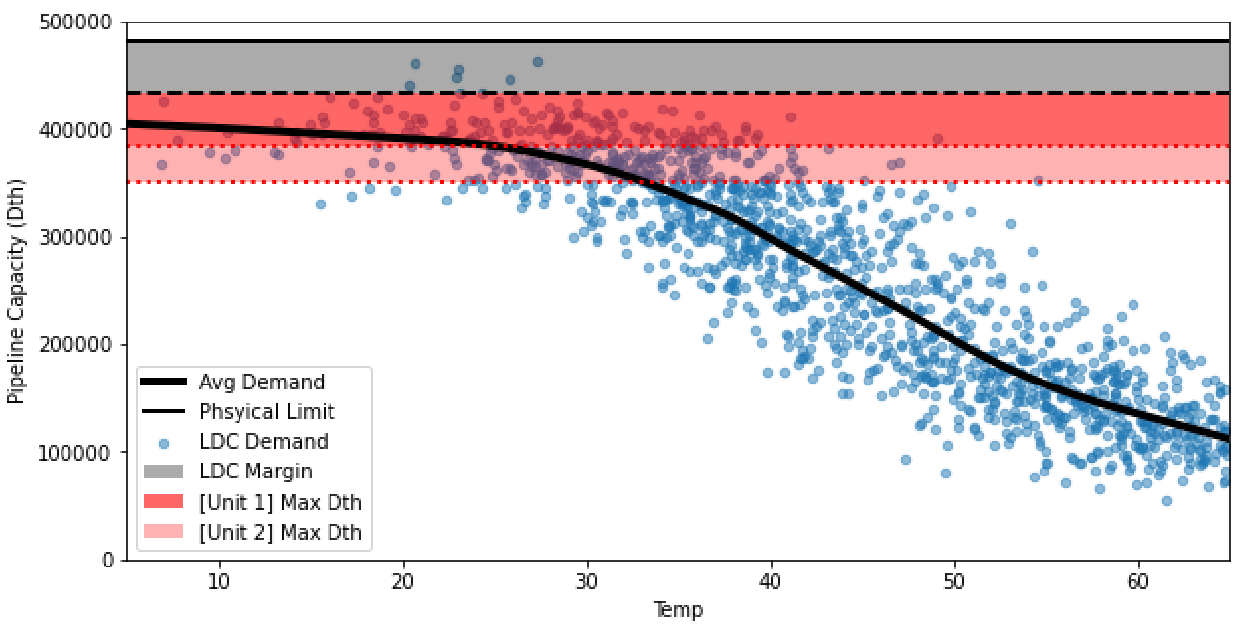
cold weather performance of the resources located on the AGT G and I laterals is despite the fact that they are within the AGT Citygate pricing hub. That implies that there are *physical* constraints on gas availability for these resources, rather than economic limits – which makes sense given their locations at the end of constrained laterals.

2.5) Alignment of Results with other Data Sources (G-Lateral Case Study)

Teasing out truly physical limits on gas availability is difficult due to the interconnected nature of the gas system, however it is possible to get a sense of these physical limitations on the Algonquin G-Lateral due to its topology: a single receipt point on the Algonquin mainline and no outflow downstream. As noted in Table 1, there are two gas-only power plants on the G-Lateral, [UNIT 1] and [UNIT 2]. Additionally, it appears from the Firm Transportation contract holders listed in the AGT Informational Postings website that all – or almost all – of the lateral's physical limit of 481,000 Dth/d is held by gas LDCs.[18]

Figure 3 depicts daily LDC gas demand for the period December 2016 through February 2022, relative to the pipeline's physical limit, LDC reserve margin, and potential demand from the generators.[19]

Figure 3: G-Lateral LDC Gas Demand



While the pipe has a physical limit of 481,000 Dth/d, the LDCs hold about 10% back to provide reserve margin. We shade this headroom area in grey to indicate that is not available for power generation. Below this, two shaded areas reflect maximum gas demand at [UNIT 1] and [UNIT 2] (ranked by heat-rate).

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[18] It appears that there may be two small contracts held by marketers, but at least one of those contracts is identified by the Eversource LDC, in its "Forecast and Supply Plan" filed with the MA DPU, as helping meet LDC demand.

[19] All gas data was sourced from our data provider, Genscape.

At temperatures above 40 degrees, it appears that both gas units should be able to get gas in any quantity they desire, but as temperatures fall and LDC demand rises, gas available for power generation falls. Between about 25 degrees and 33 degrees, physical gas availability at [UNIT 2] should decline to near zero (assuming [UNIT 1] takes priority). This aligns with the values identified in Table 2. The more efficient [UNIT 1], by contrast, has full access to gas until 33 degrees and somewhat declining access thereafter. This conforms with the better gas access that Table 2 attributes to [UNIT 1] compared to [UNIT 2]. While far from conclusive, this case study provides physical support to the expected-vs-observed generation analysis presented above.

2.6) Gas Availability Conclusions

This study compares the observed performance against the expected performance of New England's gas-only generation fleet with the intent of discerning how impactful gas constraints are on generator performance under a range of temperature conditions. The study does not suggest that any one resource would be impervious to gas availability constraints in extreme cold weather condition, but it does suggest that certain resources would have difficulty obtaining gas before others and that location appears to be the dominant factor. Specifically, the analysis suggests that resources interconnected to Iroquois or AGT upstream of Burrillville appear to have the least risk. Facilities in Maine and on the AGT –G and –I laterals have the most pronounced risk. The remaining facilities fall somewhere in between.

This analysis offers two key insight into how ISO-NE should consider fuel constraints in its RCA project. First, it is not reasonable to assume that all resources have equal access to pipeline gas. This neither aligns with economic theory nor observed system performance. Second, Individual units have observable differences in fuel availability and these locational attributes should be integrated into the RCA analysis.

A final note: we readily acknowledge that this analysis relies on a variety of public sources to characterize unit dispatch. These are limitations of our specific derate estimates, not of the methodology itself. ISO-NE has wealth of confidential unit-specific offer data and sophisticated market simulators to reproduce this analysis with greater fidelity.

3) Integrating Gas Availability in the RCA Project

The ISO's proposed approach of uniformily derating non-firm gas-only resources is not reasonable. There are at least two methods to integrate unit-specific gas modeling into RCA. Either approach would be preferable to the ISO's current proposal. The two approaches have different tradeoffs between specificity in the number of molecules available in the region and to which units those molecules flow.

3.1) Model each gas-only resource as a profiled resource

Modeling each gas-only resource as a profiled resource would allow analogous treatment between all resources with uncertain fuel arrangements. Gas units could be modeled as having an hourly profile of expected "availability", where availability is a function of temperature. Each unit would have its own profile, reflecting its unique winter performance. Modeling gas resources as a profiled resource would entirely replace the ISO's proposed approach.

In theory, gas availability constraints could be integrated into GE MARS either by adjusting unit capacity or by adjusting unit outage rates.[20] In a given MARS instance, a unit's output is the product of a random variable representing forced outage (EFORd) and its qualified capacity (QC). Ideally, gas constraints would be modeled as an additional random variable, akin to forced outage, representing the likelihood of fuel unavailability, *conditional on temperature and location*. The ideal approach would have an equation along the lines of:

$$Unit\ Output_h = Nameplate\ MW \times EFORd \times Fuel\ Access$$

The new $Fuel\ Access$ variable would either indicate that gas was available (no derate required) or gas was not available (total derate). It is our understanding that MARS cannot add random variables (such as fuel availability) which are *conditional* on a parameter such as temperature, so adjustments to outage rates appear infeasible. To that end, we focus on changes to the other variable – unit capacity – that could be reflect fuel availability.

We suspect that gas-only resources could be modeled using an hourly profile, which exogenously embeds *expected* fuel availability. It is our understanding that the ISO intends to rely on historic load profiles in GE MARS and time-matched renewable generation profiles, so this would align analytical approaches for both resource classes. More specifically, we propose that:

$$Unit\ Output_h = [Nameplate\ MW \times (1 + E(Fuel\ Access \mid Hour))]\ \times EFORd.$$

This is analytically feasible to model because expected fuel access in a given hour can be computed based on known temperatures from the historic base year and the results from Table 2, above. In the same way that ISO-NE might rely on a load profile from 2016 and would rely on wind-speed / output from each resource for the same hour of the base year, the ISO could compute expected fuel access in each hour *based on observed temperature in that hour*. Procedurally, this profile could be computed in five steps:

1) Determine expected gas availability on a unit-specific, temperature-specific basis, akin to the results we present in Table 2.
2) Determine the region's temperature for each hour of the MARS load profile.
3) Lookup the odds of fuel access for each unit based on results from Step 1, indicating odds of not running when expected, by temperature. In many hours, fuel-adjusted output would equal 100%, but in some cold hours or days, that value might be considerably less than 100%.
4) Multiply nameplate MW by expected fuel access.
5) Run GE MARS with profiled gas-only resources, including a random variable for EFORd, to compute unit-specfic MRI values.

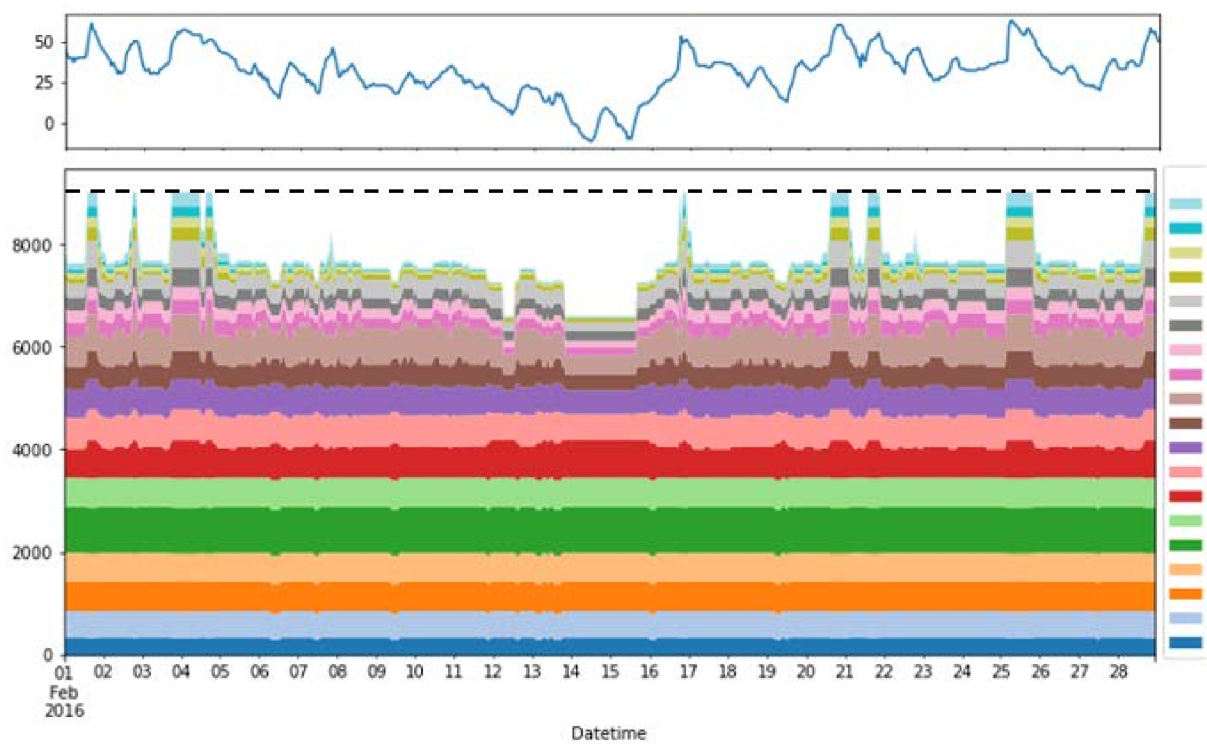
[20] Consider a resource that has a 1-in-5 chance of having gas available for power generation. Within the context of a Markov chain Monte Carlo (MCMC) simulation like GE MARS, it should be roughly equivalent to create a random variable which has a 20% chance full gas availability and an 80% chance of no gas availability or to directly assign an 80% derate in each hour (the expected value of the random variable itself).

One small wrinkle: unlike wind or solar resources where EFORd can be "integrated" into the hourly output profile, for gas resources the EFORd should be applied *in addition to* the fuel-availability profile derate. This requires a modification to the existing EFORd metrics because those *already* include a representation of gas unavailability through the inclusion of GADS codes 9130, 9131, 9134. In order to avoid double-counting, adjusted EFORd metrics should exclude outages for fuel unavailability and reflect only non-fuel outages.

Figure 4 depicts how this derating could be applied to weather data from February 2016, using the derating values we present Table 2. The upper pane reflects the hourly temperature at Bradley Field for the month and the lower pane reflects the cumulative hourly output potential of the gas-only fleet.

February 2016 had average temperatures of 31.3 Degrees but significant range. The monthly high was 63 degrees and the monthly low was -11 degrees. Figure 3 shows that when temperatures are warm (i.e., above 50), the full 9,080 MW of winter capacity is available to the system. When temperatures are in the 30s, the fleet can produce 7,684 MW and available capacity declines to a low of 6,625 MW in the near-zero weather observed mid-month. Of course, in other parts of the year, when temperatures are consistently warmer, there would be no fuel-related gas derate at all.

Figure 4: Profile-Based Derating Example



If the lumpiness of derates poses a problem for GE MARS, Table 2 could be recomputed using rolling-daily average temperatures rather than hourly temperatures. This would not affect the hourly generation profiles but would smooth unit availability and create level, 1-day generation blocks.

This approach could be enhanced in various ways. For example, instead of relying on *hourly* temperature, derates could be computed based on a *rolling average* temperature or daily HDDs. This would result in "smoother" derate curves. Similarly, the 10 degree bins generated in Table 2 could be refined and statistical methods could be employed to estimate continuous estimates.

3.2) Allocate the total quantity of gas capacity identified using the ISO's proposed approach to specific resources based on their respective derate factors at a cold temperature

Under the ISO's proposed approach, all non-firm gas resources would receive a uniform (pro rata) derate of its winter QC – based on the ISO's estimate of aggregate gas availability.[21] Under this approach [Unit A] and [Unit R] would be derated by the same proportion, even though [Unit R] performs at or above expected levels across all studied temperatures and [Unit A] produces 97% less energy at cold temperatures than expected (according to Table 2). That does not make sense.

To that end, instead of pro rata derates for all non-firm gas units, the ISO could instead derate based on an estimate of cold weather performance. This would not change the quantity of aggregate MWs available to gas generation but changes *distribution* of QC between resources. For example, the ISO could allocate gas availability based on the weighted-QC average 10 Degree derate factors in Table 2. Under this approach instead of all resources receiving a 27% derate (based on the fleet average derate calculated in Table 2), [Unit A] would have a very high derate and [Unit R] would have no derate at all – even though it is not a "firm fuel" resource.

Of course, specific rules would need to be developed to ensure that the aggregate winter fuel-derated (DQC) matches the sum of unit-specific DQC values and that resources do not exceed their "base" QC.

This approach would integrate more closely into the ISO's analytical framework while still better expressing unit-specific differences. A unit in a poor gas availability area would have a lower DQC than a unit in a gas-rich area. This approach has a potential shortcoming, however: better allocation factors for specific resources cannot ameliorate inaccuracies in the ISO's aggregate DQC estimate.

4) Conclusions

LS Power agrees that the current capacity accreditation approach in New England has room for improvement. We have previously argued that unit-specific MRI is the "first best" approach to enhancing accreditation – but only if the models can capture salient unit-specific operational characteristics and locational attributes.[22]

Developing locational estimates of gas availability should be a key analytical priority in the RCA project and we hope that this analysis provides an actionable approach for thoughtfully integrating gas constraints into QMRIC values.

[21] Slides 15-21: https://www.iso-ne.com/static-assets/documents/2023/01/a05a_mc_2023_01_10-12_rca_iso_gas_accreditation_presentation.pptx
[22] Slide 10: https://www.iso-ne.com/static-assets/documents/2022/07/a02_mc_2022_07_12-14_rca_ls_power_presentation.pdf

Our analysis in Section 2 demonstrates that there is significant variability in gas availability. This analysis offers two key insight into how ISO-NE should consider fuel constraints in its RCA project. First, it is not reasonable to assume that all resources have equal access to pipeline gas. This neither aligns with economic theory nor observed system performance. Second, Individual units have observable differences in fuel availability. Our results suggest that resources interconnected to Iroquois or AGT upstream of Burrillville appear to have the least risk. Facilities in Maine and on the AGT –G and –I laterals have the most pronounced risk. These locational attributes should be integrated into the RCA analysis.

The two methodologies we outline in Section 3 offer different approaches to enhance the fuel attribution in RCA. The two approaches have different tradeoffs between specificity in the number of molecules available in the region and to which units those molecules flow. Both approaches are material improvements over the ISO's current proposal and both could be implemented without onerous modifications.

LS Power remains hopeful that RCA can improve regional reliability, provide actionable price signals for generators, and ensure that consumers get what they pay for. Accurate modeling of, and pricing for, gas only resources must be a top priority for the region. We hope that the analytical results presented here provide ISO-NE, and stakeholders broadly, with a better view of what is at stake and what can be done to enhance this aspect of capacity accreditation.