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January 13, 2025

By Email and RESS

File No.: 1019261173

Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto ON M4P 1E4

Attention: Nancy Marconi, Registrar

Dear Ms. Marconi:

Re: Independent Electricity System Operator
Application by NQS Generation Group for Review of Amendments to Market Renewal Program
Response to Undertakings
Ontario Energy Board File No. EB-2024-0331

The IESO's responses to undertakings given during the examination of its witness panel at the Technical Conference held on January 9, 2025 is attached and will be filed through RESS.

Yours truly,

Patrick G. Duffy

PGD/sb
cc. All parties to the proceeding

IESO RESPONSES TO TECHNICAL CONFERENCE UNDERTAKINGS

Reference	Undertaking	Response
JT1.1	IESO TO PRODUCE THE DATA AND ANALYSIS USED TO SUPPORT ITS MARKET PARTICIPANT DATA CALCULATIONS, TOGETHER WITH ANY EXPLANATIONS (UNDER ADVISEMENT)	The IESO maintains its refusal. The Applicants are asking the IESO to retrieve and produce a significant amount of data, including confidential market participant bid and offer data, for a document that has been available to its members since September 2022. The Business Case Validation Memo was not included with, or referenced in, the IESO's Descriptive or Responding Evidence and was first introduced into the record by the Applicants at the Technical Conference. If the Applicants believed it was necessary for their expert to review this data, then the Applicants should have requested it at an earlier date. Further, the IESO is refusing to answer the question because it is not a relevant issue in the proceeding and therefore lacks foundation. The application filed by the Applicants does not take issue with the MRP Business Case and Power Advisory did not dispute the MRP Business Case in their report[1] or at the Technical Conference.[2] The IESO's understanding is that the benefits associated with the Amendments are not being contested in this proceeding by the Applicants.
JT1.2	IESO TO CONFIRM THAT THE 1,300 HISTORICAL RESOURCE COMMITMENTS WERE WITHIN THE NQS GROUP (UNDER ADVISEMENT)	The IESO confirms that the 1,300 historical commitments inspected for the MRP Business Case were commitments of NQS resources. The IESO will not undertake an analysis to determine which of those commitments were for the facilities listed in Appendix A of the Power Advisory report.
JT1.3	IESO TO CREATE AND PRODUCE A CHART IDENTIFYING THE MARKET SURVEILLANCE PANEL AND AUDITOR GENERAL OF ONTARIO CRITIQUES AS IT RELATES TO THE REAL-TIME GENERATOR COST GUARANTEE PROGRAM, THE DATE OF THOSE CRITIQUES, TOGETHER WITH THE STEPS THE IESO TOOK TO ADDRESS THOSE CRITIQUES AND THE DATE THAT THOSE STEPS WERE IMPLEMENTED TO ADDRESS THOSE CRITIQUES (REFUSED)	The IESO maintains its refusal. See the response to JT1.10 for copies of the IESO's responses to the MSP's recommendations.

[1] The MRP Business Case is cited in footnotes 3 and 4 of the Power Advisory report without comment.
[2] Technical Conference Day 2 Transcript, p 157, line 25 to p 158, line 5.

Reference	Undertaking	Response
JT1.4	IESO TO PROVIDE ANY INFORMATION OR DATA ON THE NUMBER OF NQS GENERATORS THAT CURRENTLY PARTICIPATE IN THE DAY-AHEAD COMMITMENT PROCESS ON AN INCREMENTAL-ENERGY-OFFER-ONLY BASIS, WITHOUT RELIANCE ON THE GENERATOR COST GUARANTEE PROGRAM (REFUSED)	The IESO maintains its refusal and will not undertake an extensive review of data to respond to this question. The IESO confirms its understanding, as stated at page 7 of its responding evidence, that most NQS resources choose to submit three-part offers because they prefer to receive a cost guarantee.
JT1.5	IESO TO CONSOLIDATE THE INFORMATION IT CONSIDERED INTO EVIDENCE IN THE PROCEEDING THAT WOULD SUPPORT ITS CONCLUSION AND ASSERTION (UNDER ADVISEMENT)	The IESO's statement that ISOs and RTOs in the United States use shorter look-ahead periods because they are less reliant than Ontario on combined cycle gas plants to meet peak demand was based upon Mr. Matsugu's knowledge gained from working in the sector since 2006, including serving as the IESO representative on the ISO/RTO Markets Committee. That ISOs and RTOs in the United States utilize combined cycle gas plants to largely serve base and intermediate load, while generally using less efficient resources to meet peak demand, is common knowledge in the sector. Attached as **Appendix A** is an article published by the U.S. Energy Information Administration which discusses the role of combined-cycle gas plants in the major electricity regions of the United States and highlights their importance in serving base and intermediate load in those regions.
JT1.6	IESO TO CONDUCT A VALIDATION PROCESS RE CMSC	The IESO confirms that only Congestion Management Settlement Credit (CMSC) payments are subject to recovery under the current MPM regime. See MR, Ch 7, App 7.6: Local Market Power and Market Manual 2.12: Treatment of Local Market Power.
JT1.7	IESO TO PROVIDE THE DOLLAR AMOUNT OF EX-ANTE MITIGATION OR EX-POST SETTLEMENT ADJUSTMENTS UNDER THE DAY-AHEAD COMMITMENT PROCESS, UNDER THE CURRENT MARKET POWER MITIGATION REGIME FOR THE 2018 TO 2023 TIME FRAME (REFUSED)	The IESO maintains its refusal.
JT1.8	IESO TO PROVIDE A LIST OF MR. MATSUGU'S PRESENTATIONS, GUEST LECTURES, OR JOURNAL ARTICLES RELEVANT TO MATTERS IN THE PROCEEDING (UNDER ADVISEMENT)	The following are recent examples: • Mr. Matsugu was a member of a panel entitled "Redesigning Markets to Inform and Attract Investment" at the 8th Annual Electricity Workshop | Ivey Energy Policy and Management Centre held on October 15, 2024.

Reference	Undertaking	Response
		• Mr. Matsugu was a guest instructor on designing wholesale markets for the spring/summer 2020 Electricity Markets Course for Ryerson University, Faculty of Engineering and Architectural Science, Department of Electrical and Computer Engineering.
JT1.9	IESO TO PROVIDE A LIST AND CAPACITY OF THE NATURAL GAS GENERATION FACILITIES THAT ARE NON-QUICK START AND ARE NOT PART OF THE NQS GROUP	Please see **Appendix B** for a list of natural gas generating facilities in the province. The IESO has identified whether the facility is listed in Appendix A to the Power Advisory Report and whether it is eligible for PCG/GCG payments.
JT1.10	IESO TO FILE THE FILINGS REQUIRED UNDER SECTION 6.25 OF THE IESO'S LICENCE, SINCE THE FIRST MSP RECOMMENDATIONS, RELATED TO THE ISSUES ADDRESSED BY THE MARKET RENEWAL PROGRAM AND THE MRP AMENDMENTS	Section 6.2.5 was introduced into the IESO's licence in 2013. In accordance with that provision, the IESO filed reports with the OEB for the 2015 to 2024 years. Copies of these reports will be filed by the IESO individually through RESS. As stated in the MSP's State of the Market Report 2023 (published in September 2024), the IESO anticipates that 18 of the previous Panel market design recommendations will be addressed through MRP. The MSP intends to release an MRP pre-deployment report by early 2025 that, amongst other things, will set out its plans to evaluate how MRP has addressed the market inefficiencies raised in past MSP recommendations where the MRP program was identified as the remediation measure for the underlying issue.
JT1.11	IESO TO PROVIDE ITS POSITION ON WHETHER THE MRP AMENDMENTS DISCRIMINATE AGAINST THE NQS GENERATORS, BUT THAT DISCRIMINATION IS JUST; OR THAT THE MRP AMENDMENTS DO NOT DISCRIMINATE AGAIN THE NQS GENERATORS; USING "DISCRIMINATE" IN THE SENSE OF "ECONOMIC DISCRIMINATION", AS DEFINED BY THE OEB (UNDER ADVISEMENT)	The IESO is unclear on the precise nature of the Applicants' unjust discrimination claim in this proceeding. The Applicants have failed to provide a basis for why the grouping of their facilities (listed in Appendix A to the Power Advisory Report) should be treated as a "class of market participants" for the purposes of subsection 33(9) of the *Electricity Act, 1998*. The Applicants' facilities share no unique characteristics that distinguish them from other NQS generation facilities in the province[3] and include facilities that are not eligible for cost guarantee payments.[4] It is the IESO's position that the Applicants' facilities do not constitute a "class of market participants". Further, as Power Advisory's evidence was based on the impact of the Amendments on a fictional proxy generator – the impact of which was then extrapolated to all of the

[3] Technical Conference Day 2 Transcript, p 28, line 2 to p 29, line 6
[4] Technical Conference Day 2 Transcript, p 131, line 25 to p 132, line 14 and p 156, line 2 to 16

Reference	Undertaking	Response
		Applicants' facilities without any regard for their individual characteristics[5] or the possibility that another NQS resource would receive a replacement commitment in place of the proxy generator[6] – the Applicants have not provided any basis for an allegation of unjust discrimination against an individual member of the group. It is not evident to the IESO how the Applicants can advance a claim of unjust discrimination against individual market participants given the evidence that has been filed. In any event, the IESO's position is that the Amendments are not discriminatory against NQS generators, either as a class or against individual market participants. The Amendments account for the unique characteristics of the NQS generators (through the use of mechanisms such as three-part offers and the cost guarantee programs) to place them on an equal footing as other generation resources on a total cost basis in the IESO commitment and scheduling processes. Should the Amendments be found to be discriminatory as against NQS generators, either as a class or as individual market participants, it is the IESO's position that such discrimination is not unjust because the Amendments will improve overall market efficiency as has been acknowledged by Power Advisory.[7] It is the IESO's position that the Applicants have no viable basis upon which to advance an argument that the Amendments are inconsistent with the purposes of the *Electricity Act, 1998* due to their failure to advance any evidence on this point.[8]
JT1.12	IESO TO FILE THE BUSINESS CASE VALIDATION MEMO	A copy of the Business Case Validation Memo dated September 22, 2022 is attached as **Appendix C**.

[5] Technical Conference Day 2 Transcript, p 159, line 5 to p 160, line 26
[6] Technical Conference Day 2 Transcript, p 66, line 28 to p 68, line 11
[7] Technical Conference Day 2 Transcript, p 77, line 23 to p 78, line 6, p 157, line 25 to p 158, line 5.
[8] Technical Conference Day 2 Transcript, p 158, line 14 to p 159, line 4

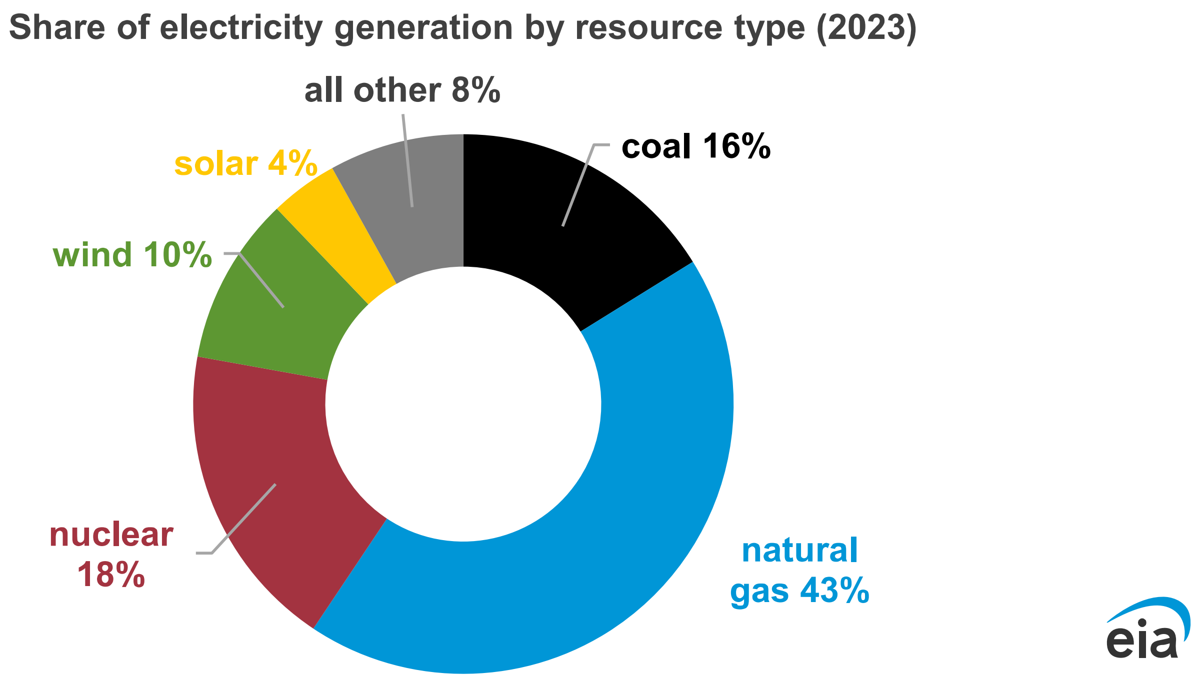
U.S. Energy Information Administration

Today in Energy

IN-DEPTH ANALYSIS

February 22, 2024

Use of natural gas-fired generation differs in the United States by technology and region



Data source: U.S. Energy Information Administration, *Electricity Power Monthly*

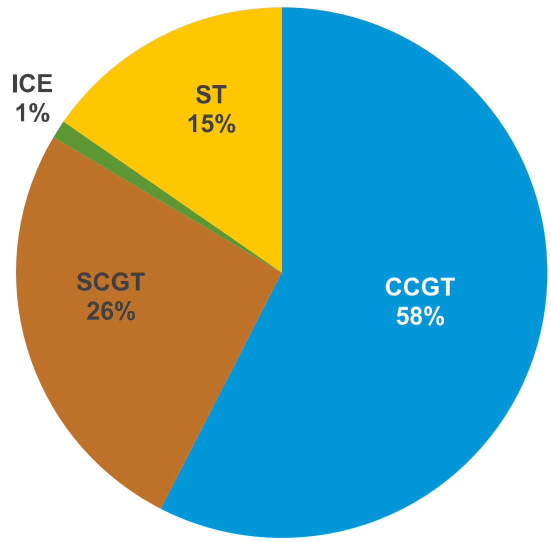
Natural gas is the single-largest source of energy used to generate electricity in the United States, making up 43% of electricity generation in 2023. Natural gas-fired power plants accounted for the second-most U.S. generating capacity additions in 2023, trailing only solar. Combined with increasing domestic supply and relatively low natural gas prices, the versatility of natural gas-fired power plants to meet a wide range of requirements across many U.S. markets is one of the main reasons for their growth. However, the dispatchability, efficiency, and broad regional coverage of natural gas-fired power plants vary significantly. In addition, decades of advancements in natural gas turbine efficiency mean that the age of natural gas-fired plants affects how those plants are used.

Natural gas-fired generation is versatile to dispatch

Nearly all natural gas-fired power plants are dispatchable, meaning that they can reliably be called on to meet power demand when needed by the grid. The flexibility of natural gas-fired generation is supported by the four different technology types used in these plants: combined-cycle gas turbines (CCGT), simple-cycle gas turbines (SCGT), steam turbines (ST), and internal combustion engines (ICE). In addition to the type of equipment, plant configurations and operating approaches differ among the technology types. In 2022, CCGT plants made up the largest part of the natural gas fleet, followed by SCGT, ST, and ICE.

Appendix A

Share of natural gas-fired generating capacity by technology type, 2022



Data source: U.S. Energy Information Administration, *Electric Power Annual*
Note: ST=steam turbine; CCGT=combined-cycle gas turbine; SCGT=simple-cycle gas turbine; ICE=internal combustion engine

CCGT plants are highly efficient, which allows them to generate low-cost power over extended periods, and they are configured to provide power to serve base and intermediate load. The three other plant types (SCGT, ST, and ICE) are used mostly to meet peak demand on the electric grid and so run less frequently. These three sources can start and ramp up to full power quickly, which is critical in markets with an increasing concentration of intermittent renewable generation.

In 2023, operators added 9,274 megawatts (MW) of new natural gas turbine generating capacity to the power grid in the United States. This total consisted of 7,376 MW of capacity from CCGT plants, 1,756 MW from SCGT plants, and 142 MW from ICE plants. No capacity from ST was added in 2023.

Natural gas consumption varies by plant type

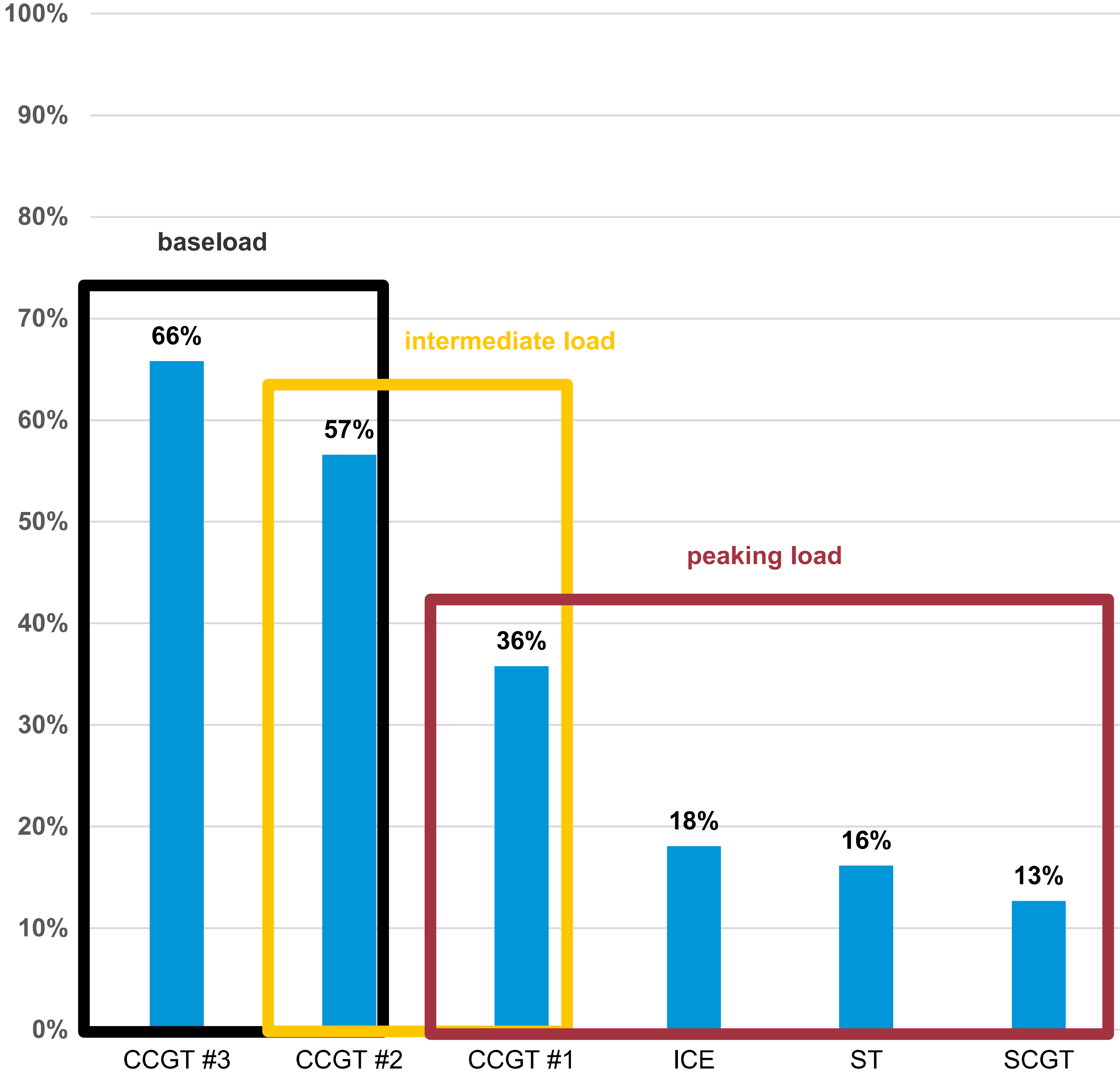
The different types of natural gas-fired power plants technologies lead the plants themselves to have different operating rates, or capacity factors, among the technologies. A capacity factor is the ratio between the amount of generation over a period of time and the generating capability of a power plant.

CCGT plants, with higher efficiency, typically run more than half of the time and had a fleetwide capacity factor of approximately 56% in 2022. Depending on the age and type of equipment of the plant, capacity factors among the CCGT fleet can vary. The newest CCGT plants (those that entered service between 2014 and the end of 2023 and are using the latest generation of natural gas turbines) recorded the highest average capacity factor in 2022, approximately 66%. CCGT plants that started operating between 1999 and 2013 with an earlier natural gas turbine model reported a slightly lower average capacity factor, about 57%, in 2022. Average capacity factors were lowest, about 36%, for the earliest group of CCGT plants, which began operating in the 1980s and up until 1998.

SCGT, ST, and ICE natural gas-fired generating facilities all had average capacity factors below 20% in 2022 because they usually are only called on to operate when power demand is at its highest or when intermittent renewable energy sources need backup. SCGT plants had an average capacity factor of approximately 13% in 2022, ST plants of about 16%, and ICE plants of 18%.

Appendix A

Natural gas-fired generation capacity factor by plant type (2022)
percentage



Data source: U.S. Energy Information Administration, *Electric Power Annual*
Note: CCGT=combined-cycle gas turbine; SCGT=simple-cycle gas turbine; ICE=internal combustion turbine; ST=steam turbine
CCGT #1=started operating in 1980–1998
CCGT #2=started operating in 1999–2013
CCGT #3=started operating in 2014–2022

The efficiency of power plants is measured by a ratio of fuel consumed to output in kilowatthours, referred to as a heat rate. A low heat rate means that a facility is using less fuel to produce the same amount of electricity as other facilities with the same type of turbines. The most modern and efficient CCGT plants, those entering service sometime between 2014 and 2023, typically have heat rates less than 7,000 British thermal units per kilowatthour (Btu/kWh). Older facilities that opened between 1999 and 2013 average around 7,500 Btu/kWh. In contrast, SCGT and ST natural gas-fired plants typically have heat rates greater than 10,000 Btu/kWh, or at least one-third higher than a CCGT facility.

Heat rates are an important measure of fuel requirements by the natural gas-fired generating fleet. For example, the most modern CCGT plants generated approximately 16% of all electric power from natural gas-fired plants in 2022 while consuming only about 14% of total energy use. In contrast, the SCGT fleet consumed nearly the same amount of fuel as CCGTs in 2022 but accounted for about 9.0% of total natural gas-fired generation. Differences in heat rates, especially when natural gas prices are elevated, can greatly affect the economics of generation using natural gas.

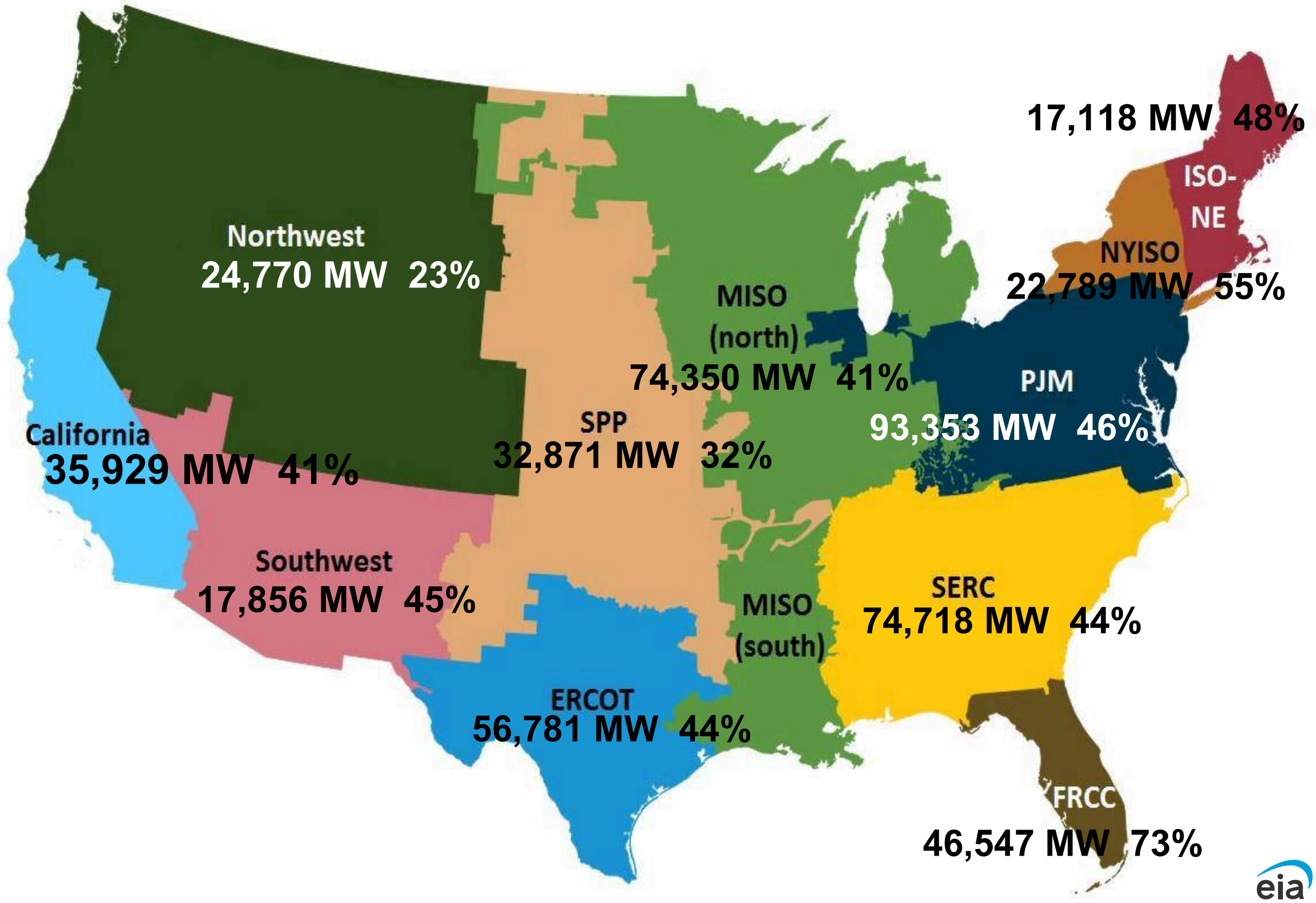
Appendix A

Capacity factors and efficiency ratings are good predictors of which plant type may be added or retired from the natural gas-fired generating fleet. As the natural gas-fired power fleet becomes more efficient in the future, steam boiler plants and older SCGT facilities using natural gas will be retired, and more CCGT plants using the latest natural gas turbine technology will be added.

Natural gas-fired generation has broad national coverage

All 11 major electricity regions in the United States rely on natural gas to meet a significant share of their power load. Regions with the largest concentration of natural gas-fired power plants are in the eastern half of the United States, where natural gas production has increased alongside developing shale and tight resources. Natural gas production growth from the Marcellus shale region has boosted natural gas generation in PJM, the Midcontinent Independent System Operator (MISO), and parts of SERC. Natural gas-fired capacity in the Electric Reliability Council of Texas (ERCOT) also has been affected by increased natural gas production in that state.

Natural gas-fired generating capacity by RTO/region (2022)



Data source: U.S. Energy Information Administration, *Electric Power Annual*
Note: RTO=Regional transmission operator. The total natural gas-fired capacity across MISO (north) and MISO (south) is 74,350 MW.

Based on 2022 data from our *Electric Power Annual*, regions with the highest capacity factors for CCGT plants are in the eastern half of the United States. SERC, PJM, FRCC, and MISO all recorded capacity factors for their respective CCGT fleets at or greater than the national average of 56%. CCGT plants in the SERC and PJM regions, which are newer and more efficient on average, were operating more than 60% of the time during 2022. PJM and FRCC are home to some of the most modern and highest efficiency natural gas turbines in the United States.

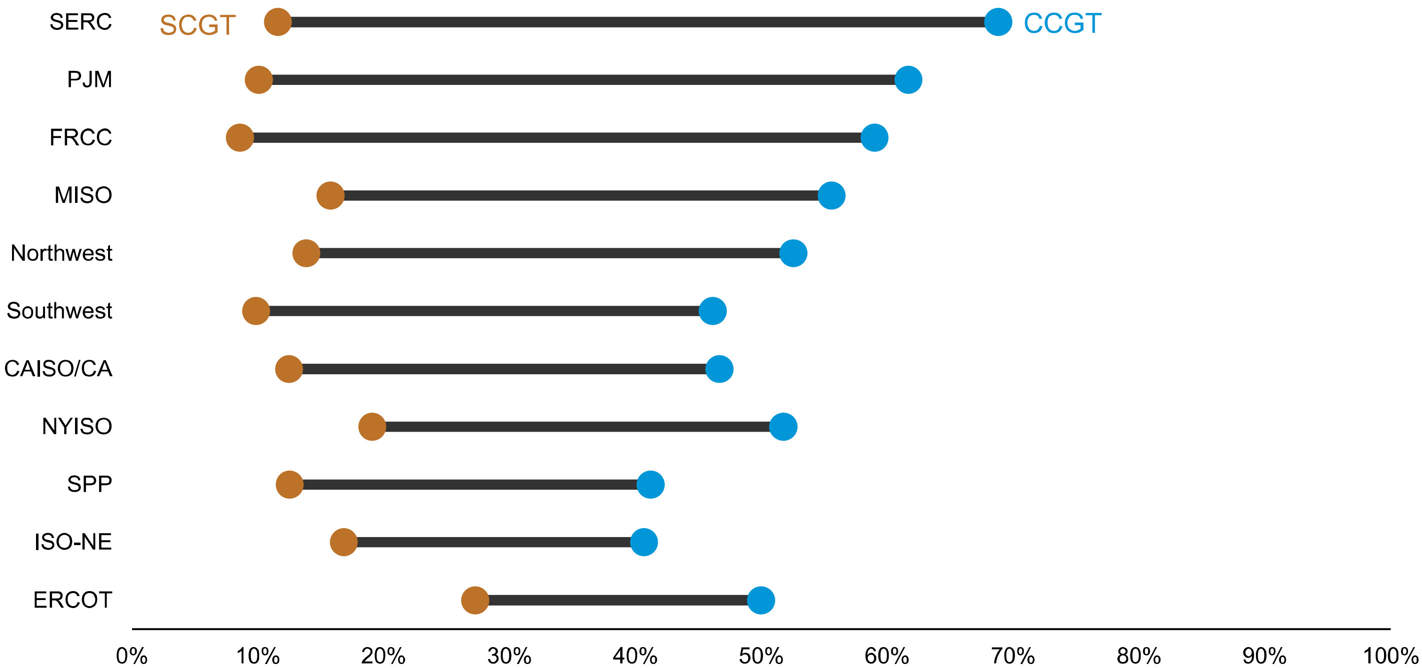
In contrast, average capacity factors for CCGT plants in four regions—the Independent System Operator-New England (ISO-NE), SPP, the Southwest, and the California Independent System Operator (CAISO)—all were less than 50% during 2022. Capacity factors in ISO-NE and SPP were especially low at 41% in 2022, and in CAISO, they were about 47%. The lower percentages mostly were due to more generation from wind and solar sources in SPP and CAISO and constrained winter natural gas supply in ISO-NE.

Capacity factors for SCGT plants regionally were different than that for the CCGT fleet. The SCGT fleet in five regions (ERCOT, the New York Independent System Operator, ISO-NE, MISO, and the Northwest) had average capacity factors greater than the national average of 13% in 2022. Of special note, the SCGT fleet in ERCOT had an average capacity factor of approximately 27% in 2022. This extremely high rate was due to ERCOT's record-high demand for electricity during both the summer and winter, as well as intermittent operation from the region's large wind turbine fleet.

Six regions that had lower peak demand on an hourly basis in 2022 relied less on SCGT output than the national average. These regions were SPP, CAISO, SERC, PJM, FRCC, and the Southwest.

Appendix A

Average capacity factors for CCGT and SCGT by region (2022)



Data source: U.S. Energy Information Administration, *Electric Power Annual*
Note: CCGT=combined-cycle gas turbine; SCGT=simple-cycle gas turbine

Principal contributors: Mark Morey, Scott Jell

Appendix B

LIST AND CAPACITY OF THE NATURAL GAS GENERATION FACILITIES

Facility Name	Capacity	Member of NQS Group (as per PAReport Appendix A)	Eligible for PCG/GCG Payments
BIRCHMOUNT CGS	2.6		N
BRIGHTON BEACH CGS	583.75		Y
BUR OAK CGS	3.25		N
CARDINAL POWER CGS	156.34		Y
COCHRANE CGS	22.24		Y
EAST WINDSOR CGS	84	Y	N
EMERALD ENERGY FROM WASTE CGS	10.3		N
GREENFIELD ENERGY CENTRE CGS	1040		Y
GSPC CGS	314		Y
GTAA CGS	90		Y
HALTON HILLS CGS	641.5	Y	Y
KAPUSKASING GS	40		Y
KINGSTON COGEN CGS	110		Y
LAKE SUPERIOR POWER CGS	128		Y
MAITLAND COGEN 1	45.7		Y
NAPANEE GENERATING STATION	900	Y	Y
NELSON CHP II CGS	12		N
NIPIGON GS	20.51		Y
NORTH BAY GS	32.9		Y
NORTHLAND IROQUOIS FALLS CGS	120		Y
NORTHLAND KIRKLAND POWER (SCGT)	28.868		Y
NORTHLAND KIRKLAND LAKE POWER (CCGT)	81		N
OTTAWA HEALTH SCIENCE CENTER CGS	73.7		Y
PORTLAND ENERGY CENTRE CGS	550	Y	Y
SARNIA CGS	444	Y	Y

Appendix B

SITHE GOREWAY CGS	839.1	Y	Y
ST. CLAIR POWER CGS	577	Y	Y
THOROLD GS	241.6	Y	Y
TUNIS GS	36.5		Y
WEST WINDSOR POWER CGS	122.78		Y
WHITBY COGEN CGS	50		Y
WINDSOR TRANSALTA CGS	72.28		Y
YORK ENERGY CENTRE CGS	393	Y	N

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Memorandum

To: **MRP Implementation Engagement Stakeholders**

From: Tom Chapman, Sr. Manager, Wholesale Market Development

Date: September 22, 2022

Re: Market Renewal Program Business Case Validation

Following the establishment of a new project schedule and budget, the IESO undertook a review of the MRP Business Case originally developed in 2019. The IESO concluded that the Business Case remains sound, and the renewed market will deliver substantial net financial benefits of at least $700 million to Ontario consumers over the first 10 years of operation.

The review included an assessment of whether the expected benefits, costs, and other underlying assumptions have materially changed given a refreshed MRP project schedule and budget, as well as an updated view of the IESO's forecasted demand and supply projections. The updated net benefits are lower than the 2019 calculated estimate of $800 million as implementation and costs to operate the new market have increased by $92 million, as some of these costs were unknown during the 2019 Business Case preparation. The new market will still yield the same benefits from quantifiable market efficiencies and the elimination of unnecessary congestion management settlement credits (CMSC) of $975 million over the first 10 years. The updated net present value of the program is $266 million which falls within the 90% probability range of NPV values that were calculated for the 2019 Business Case. Other benefits, through optimization and operational certainty, that were not quantified in the Business Case are expected to increase as the sector is evolving to include new and more diverse resource types, such as storage and hybrids.

The renewed market will build on and enhance the IESO's ability to deliver on core priorities of preparing for future transformation of the sector and ensuring cost-effective reliability of the Ontario electricity system. Efficient operation of existing resources and effective integration of new resource types is dependent on the foundational improvements MRP will deliver – prices that reflect costs in the different regions across the province and significantly improved optimization of supply resource scheduling and dispatch. Effective integration of storage and other new resource technologies would not be possible in today's two-schedule market without significant compromise to their potential and increased integration costs, especially with growing future uncertainties related to fuel and resource development costs. Together the improvements delivered by MRP will significantly improve our ability to provide optimal use of resources available on any given day, and send clear signals to identify where additional resources are needed in the future.

Key Updates and Findings of the Validation of the MRP Business Case

1. Quantifiable Benefits

The estimated total benefits of $975M from 10 years of operating the new market remain the same with a shift in the launch of the new market from 2023 to 2025. These benefits include $525M from market efficiency improvements and $450M from avoiding unnecessary congestion management settlement credit payments.

Market Efficiency Benefits

The calculated market efficiency benefits of $525 million in the first 10 years are achieved through more efficient unit commitment and optimization, improved intertie pricing, and locational pricing incentivizing increased resource competition. These benefits are not affected by any schedule and budget changes, or changes in the sector and the associated forecasts because the design of the market has not fundamentally changed. Each of the quantified benefits are tabulated in the table below and further discussed.

Market Efficiency	10 Years of Efficiency Benefits ($M)
More Efficient Unit Commitment	$190
Improved Intertie Pricing	$285
Increased Resource Competition	$50
Total Efficiency Benefits	$525

The benefits of more efficient unit commitment were determined based on assessing the inefficiency of the existing process to commit resources that require lead time to come on-line and minimum operating runtimes once connected to the grid. This calculation is still valid as there will continue to be non-quick-start resources with start-up costs and minimum operational requirements that would be inefficiently scheduled in the absence of MRP. With the potential for a decarbonized and decentralized resource mix, the renewed market will be necessary for driving efficient outcomes and managing resources' operational requirements.

The benefits of improved intertie pricing also do not change with the refreshed project schedule. The Ontario market is directly connected to the Mid-Continent Independent System Operator (MISO) and New York Independent System Operator (NYISO) electricity markets and indirectly to the Independent System Operator of New England (ISO-NE) and the PJM Interconnect. These links to external markets remain and will require efficient price signals to indicate when it is economic to export or import energy. The current two-schedule pricing market sends incorrect signals leading to volumes of energy flowing out of Ontario settled at a price that does not match the costs to produce the energy. These inefficiencies were modelled in the 2019 Business Case and recent monitoring shows that these inefficiencies continue to occur where the annual estimate used in the Business Case is a lower bound of the potential benefits.

The benefits from increased resource competition also do not change with the refreshed project schedule. These benefits were determined by assuming a subset of the resource fleet would be more proactive and respond more aggressively to transparent prices. The 2% reduction in offer prices was already, and continues to be, a conservative estimate based on published literature on increased competition from market design enhancements, and from updated projections on the future demand forecast.

Elimination of Unwarranted Congestion Payments

The new market would avoid $450 million of unwarranted congestion management settlement credit (CMSC) payments in the first 10 years. The current market incurs congestion management settlement credits of which unnecessary constrained-off payments will be eliminated by the new market. The elimination of these payments are not affected by any schedule and budget changes over the first 10-year period of operating the new market. On an average annual basis, $45 million would be avoided by Ontario consumers. This level of avoided payment with the new market is consistent with the amount of constrained off payments charged to Ontario consumers in 2021.

Total Benefits

The total benefit to Ontario consumers from MRP is the sum of market efficiency benefits and the elimination of unwarranted congestion management settlement credit payments. With the IESO's conservative assessment of the total benefits, in the first ten years of operating the new market the total benefits are unchanged from the 2019 Business Case calculation and amount to $975 million.

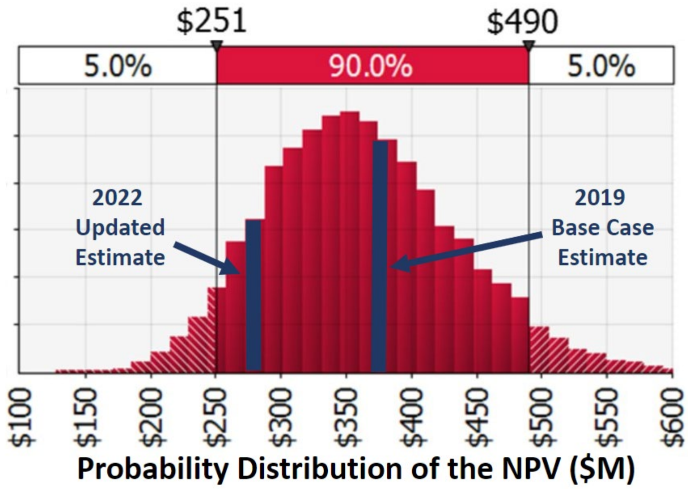
Total Benefits	10 Years of Benefits ($M)
Market Efficiency Benefits	$525
Eliminated CMSC Benefits	$450
Total Quantifiable Benefits	$975

2. Implementation and Operating Costs

In the original 2019 Business Case, MRP was expected to cost $170 million and be implemented in 2023. After the program had been implemented there was expected to be ongoing incremental maintenance costs, estimated at an additional $6 million over the first 10 years following implementation. At the time of developing the Business Case in 2019, it was not yet known if incremental staff would be required to operate the new market. With more certain costs and development schedules confirmed by vendors, the implementation timeline has been extended to 2025 with a new implementation cost estimate of $233 million. Further, the completion of the MRP Detailed Design in 2021 has also allowed for more accurate assessment of the ongoing costs over the first 10 years of operations. The total implementation and operation cost estimate, including the additional staff[1] for ongoing operation of the renewed market is $268 million or $92 million more than assumed in 2019.

3. Net Financial Assessment

Using the updated implementation and operating cost values and the same benefits, the net financial assessment of the Business Case was recalculated. The updated net present value of MRP is $266 million which falls within the 90% probability range of NPV values, which are between $251 million and $490 million as calculated for the 2019 Business Case. Despite increased cost estimates, the NPV of MRP remains strong, and underscores the value to ratepayers for implementing MRP. The figure below compares the original 2019 probability distribution of the NPV for MRP, with the 2019 base case value and the 2022 updated value estimate illustrated.



4. Benefits Not Quantified

The 2019 MRP Business Case included case studies and discussion of qualitative benefits. These included better operational and financial certainty with a day-ahead market and broader market benefits. The broader market benefits include improved signals for supporting investment and competition, indicating the need for system flexibility, and reduced energy curtailment and spilling. Given the need to acquire incremental capacity to meet increasing system needs and the focus on investigating pathways to decarbonize the electricity fleet, these unquantified benefits are expected to be even larger and of increased importance since 2019 when the Business Case was published.

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[1] MRP will introduce new features and tools that require additional resources for market operations, monitoring and ongoing maintenance and support.

In particular, with the larger anticipated volume of storage resources, the single schedule design of MRP is essential. The current IESO initiatives for storage integration and enabling new resources will be facilitated with the single schedule design as storage and other emerging resources require clear locational price signals to know when to operate economically.