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December 6, 2019

File No.: 101926.1124

BY EMAIL: BoardSec@oeb.ca

TO: ALL REGISTERED PARTIES

Dear all,

Re: IESO's Undertakings -- Association of Major Power Consumers in Ontario Application to Review Amendments to the Market Rules made by the Independent Electricity Systems Operator ("IESO")
OEB Case No. EB-2019-0242

Enclosed are the IESO's responses to its undertakings J3.1 to J3.4 and J3.7, as requested on November 29, 2019. We trust this is satisfactory.

Sincerely,

Daniel Gralnick

Encl.

cc: Glenn Zacher, *Stikeman Elliott LLP*
Patrick Duffy, *Stikeman Elliott LLP*
IESO Regulatory Affairs
James Hunter, *IESO*
Michael Bell, *Ontario Energy Board.*
Cherida Walter, *Ontario Energy Board*
Ian Mondrow, Gowling WLG

UNDERTAKING J3.1

IESO UNDERTAKING J3.1

UNDERTAKING

To verify if there were activation payments for the Transitional Demand Response Program, and if so, what the parameters were

RESPONSE

The objectives of the Transitional Demand Response Program (TDRP), introduced in 2004, were to help market participants overcome specific barriers to demand response in the short-term and increase the level of demand responsiveness in the Ontario electricity market over the medium and long term. The payment for demand response provided through TDRP was based on the three-hour ahead pre-dispatch price to a maximum of $500/MWh.

The parameters were set out in the attached Market Manual Part 5.10: Transitions Demand Response Program (TDRP) issued August 12, 2004.

PROCEDURE

Independent Electricity Market Operator

Market Manual 5: Settlements

Part 5.10: Transitional Demand Response Program

Issue 1.0

This procedure describes the process to be followed by the IMO and *market participants* in applying to participate in and requesting payment for the Transitional Demand Response Program.

Disclaimer

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Issue	Issue 1.0
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Document Change History

Issue	Reason for Issue	Date
1.0	New Release	September 1, 2004

Related Documents

Document ID	Document Title

(**This page must be removed before the document is released to the public. This section is only pertinent to *IMO*, not the public. **)

Document Control

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Distribution List

Name	**Organization**

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Market Manuals

The *market manuals* consolidate the market procedures and associated forms, standards, and policies that define certain elements relating to the operation of the *IMO-administered markets*. Market procedures provide more detailed descriptions of the requirements for various activities than is specified in the "*Market Rules"*. Where there is a discrepancy between the requirements in a document within a *market manual* and the "*Market Rules*", the "*Market Rules"* shall prevail. Standards and policies appended to, or referenced in, these procedures provide a supporting framework.

Market Procedures

The "*Settlements* Manual" is Volume 5 of the *market manuals*, where this document forms "Part 5.10: Transitional Demand Response Program".

A list of the other component part of the "*Settlements* Manual"" is provided in "Part 5.0: Settlements Overview", in Section 2, 'About This Manual'.

Structure of Market Procedures

Each market procedure is composed of the following sections:

1. **'Introduction'**, which contains general information about the procedure, including an overview, a description of the purpose and scope of the procedure, and information about roles and responsibilities of the parties involved in the procedure.
2. **'Work Flow'**, which contains a graphical representation of the steps and flow of information within the procedure.
3. **'Procedural Steps'**, which contains a table that describes each step and provides other detail related to each step.
4. **'Appendices'**, which may include such items as forms, standards, policies, and agreements.

Conventions

The *market manual* standard conventions are defined in the "Market Manual Overview" document.

– End of Section –

1. Introduction

1.1 Purpose

This procedure describes the processes related to the Transitional Demand Response Program (TDRP) including:

- Application to participate,
- Notification of intent to provide demand response (DR), and
- Request for payment.

1.2 Scope

This procedure is intended to provide *market participants* and interested potential program participants with a summary of the steps and interfaces involved in the Transitional Demand Response Program. The procedural workflows and steps described in this document serve as a roadmap for *market participants* and interested potential program participants, and reflect the requirements set out in the "*Market Rules*" and applicable *IMO* policies and standards.

The overview information in Section 1.3, below, is provided for context purposes only, highlighting the main actions that comprise the procedure as illustrated in Section 2 and described in Section 3.

1.3 Overview

The objectives of the Transitional Demand Response Program (TDRP) are to help *market participants* overcome specific barriers to demand response (DR) in the short-term and increase the level of demand responsiveness in the Ontario electricity market over the medium and long term.

1.3.1 Application to Participate in the TDRP

The *IMO* will provide date(s) for deadlines to submit applications to participate in the TDRP.

Selection of participants for the program will be based on a two-stage process. In the first stage, the *IMO* will identify those applications that satisfy the program eligibility criteria based on the applications submitted by potential program participants. In the second stage, the *IMO* will score the eligible applications according to evaluation factors reflective of the *IMO's* program objectives. Participants within a particular tranche (e.g. industrial applicants in the first round) will then be selected from the highest scoring eligible applicants within the tranche. The *IMO* will seek to select participants representing total DR capacity up to nominal targets established for each tranche.

1.3.2 Participant Eligibility Criteria

To be eligible to apply to participate in the TDRP an applicant must be an authorized *market participant* or be prepared to become an authorized *market participant* as a condition of acceptance in the TDRP. It is the responsibility of the applicant to ensure that they hold any applicable *licences* required by the *Ontario Energy Board*.

1.3.3 Project Eligibility Criteria

Applications must meet the following criteria in order to be eligible to participate in the program.

1. Participation in the program must overcome a barrier
2. The proposed demand response activities must be incremental to any current price response activities
3. The demand response provided must be measurable
4. Participants must provide assurance that the proposed demand response will endure beyond the program period
5. Projects (single *facility* or aggregation of *facilities*) must be not less than 250 kW and not more than 5 MW.

Details on these eligibility criteria are provided in Appendix B.

1.3.4 Ranking of Eligible Applicants and Apportionment of Program Target

Up to 100 MW of demand response will be accepted in the TDRP. The *IMO* will solicit applications for the TDRP in two rounds. The first round will close four to six weeks after the initial request for applications and the second round will close approximately three months after the initial request for applications. The *IMO* will *publish* the request for applications and provide the actual closing dates at that time. The *IMO* reserves the right at its sole discretion to modify and refine the program rules between rounds.

Projects accepted in the first round of applications must be commissioned and ready to participate within six months of acceptance by the *IMO*. Projects accepted in the second round must be commissioned and ready to participate within three months of acceptance by the *IMO*. Commissioning timelines may be altered at the discretion of the *IMO*.

The *IMO* has established goals for overall participation in the TDRP and desires a mix of applicants in all customer classes and segments. The provisional goals for each of the industrial, commercial and residential sectors are: Industrial - 40%; Commercial - 30%; Residential - 30%. These goals are 'soft' targets and the actual apportionment may differ from these goals.

For each of the three sectors in the first round, the *IMO* will seek to select the lesser of 50% of the provisional sectorial goal or the total DR capacity represented by eligible applicants in a given sector. For example, if the total capacity of eligible applicants from the commercial sector were only 35% of the provisional commercial goal, all of these applicants would be selected in the first round. If a particular sector is significantly under-represented in the first round of applications, the *IMO* may choose to select more DR from other sectors in that round (with a corresponding reduction in the provisional sectorial goals in the second round in order to achieve the overall target for the sector).

In the event that the total DR capacity represented by eligible applicants in a given sector and in a given round exceeds the provisional sectorial goal for that sector, the *IMO* will choose from among the eligible applicants according to their overall ranking based on the evaluation factors as listed in Table 1-1 below. The selected participants will be chosen from the highest ranked eligible applicants to achieve total DR capacity roughly equal to the provisional sectorial goal. The ranking and selection of eligible applicants will be at the *IMO's* sole discretion.

Table 1-1: Evaluation Factors Used to Rank Eligible Applications

Evaluation Factor	**Weighting in Overall Ranking**
Significance of barriers to be overcome	25
Overall fit with *IMO* TDRP objectives including but not limited to: • Permanence • Preference for load control vs. backup generation type projects	25
Expected ability to leverage to other customers and segments	20
Degree to which the proposed DR addresses an "under-served" market segment or opportunity	15
Innovative approach	15
Total	**100 points**

1.4 Participation in TDRP

Once an applicant has satisfied all eligibility criteria and has been accepted to participate in the TDRP they must notify the *IMO* on an hour by hour basis if they intend to provide demand response in any eligible trading hour. When the three-hour ahead pre-dispatch price[1] reaches $120/MWh, a program participant who intends to participate (reduce demand) must notify the *IMO*. The participant must complete IMO-FORM-1566 "Notice of Intent to Participate in the Transitional Demand Response Program", and upload it to the *Market Participant* Interface (MPI) at least two hours prior to start of an eligible trading hour. The *IMO* will download the data provided in IMO-FORM-1566 to a database. Failure to notify the *IMO* of intent to participate in a given hour, will disqualify the participant from receiving a payment for that hour.

[1] The current hour counts as the first of the three hours – for example, if the current time is 11:45 EST (HE 12), then the three-hour ahead pre-dispatch price will be for 14:00-15:00 EST (HE 15).

1.5 *Settlement* of TDRP

The payment for the demand response provided through the TDRP is the product of the three hour ahead pre-dispatch price to a maximum of $500/MWh and the calculated demand reduction (the customer's actual consumption minus the customer's baseline consumption).

Transitional Demand Response Program participants must download and complete IMO-FORM-1567 "Request for Payment for the Transitional Demand Response Program". Completed forms must be uploaded to the MPI no later than 17:00 EST, four *business days* after the last *trading day* of the month following the month in which the demand response was provided. The *IMO* will download the payment data to a database and process the *settlement amounts* on the *settlement statement* for the last *trading day* of the month following the month the demand response was provided.

Payment will be made for demand response provided in a trading hour up to a maximum of 5 MW and $500/MWh. Payments will be based on data provided by the program participant subject to audit and recovery of any overpayment as enabled by section 4.7C.3 of Chapter 9 in the *market rules* (see: MR-00256-R00-R02).

Transitional Demand Response Program participants are responsible for retaining all supporting data and documentation for each request for payment. The *IMO* or its agent may audit the supporting materials at any time.

Payment for demand response that cannot be verified through the audit, and that is determined to be an overpayment, will be recovered by the *IMO* and the TDRP participant may, at the *IMO*'s discretion, be disqualified from further participation in the program.

1.6 Roles and Responsibilities

The roles and responsibilities for the Transitional Demand Response Program are shared between TDRP applicants/participants and the *IMO* and are set out in detail in sections 2 and 3 below.

1.7 Contact Information

Unless otherwise specified in a notice to the applicant, if the applicant wishes to contact the *IMO*, the applicant can contact the *IMO* via email at helpcentre@theimo.com or via telephone, mail or courier to the numbers and addresses given on the *IMO's* Web site (www.theimo.com - or click on 'Have a question?' to go to the 'Contacting the IMO' page). Normal business hours are weekdays 8:00 AM to 5:00 PM. Telephone messages or emails may be left in relevant voice or electronic *IMO* mail boxes, which will be answered next *business day*.

If a specific alternative contact is specified in the notices or communication with the applicant, the applicant should contact such *IMO* staff directly.

– End of Section –

2. Procedural Work Flow

The following diagrams, Figures 2-1 through 2-3 represent the flow of work and information requirements relating to the Transitional Demand Response Program for the *IMO*, the primary external participant involved in the program, and any other parties.

The steps illustrated in the diagram are described in detail in Section 3.

Table 2–1: Legend for Work Flow Diagrams

Legend	Description
Oval	An event that triggers a task or that completes a task. Trigger events and completion events are numbered sequentially within the procedure (01 to 99).
Task Box	Shows reference number, party responsible for performing the task (if "other party"), and the task name or a brief summary of the task. Reference number (e.g., 1A.02) indicates the procedure number within the current *market manual* (1), sub-procedure identifier (if applicable) (A), and task number (02).
Solid horizontal line	Shows information flow between the *IMO* and external parties.
Solid vertical line	Shows linkage between tasks.
Broken line	Links trigger events and completion events to preceding or succeeding task.

2.1 TDRP Application Process

Market participants and other potential program participants must apply to participate in the TDRP. The steps in the following diagram describe the process to apply and to be accepted in the program.

Figure 2-1 is described in detail in Section 3.1, Table 3-1.

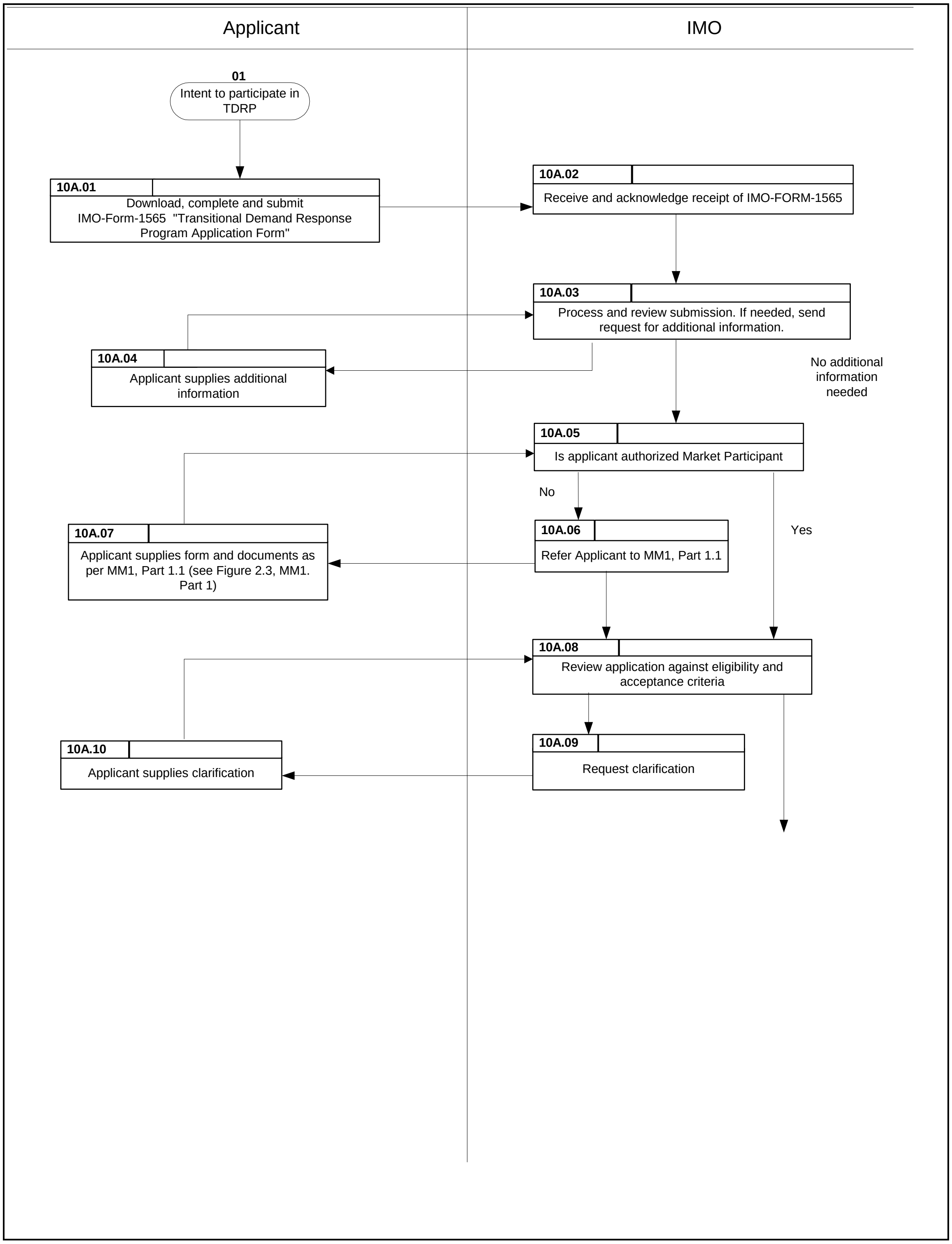

Figure 2–1: Work Flow for TDRP Application Process

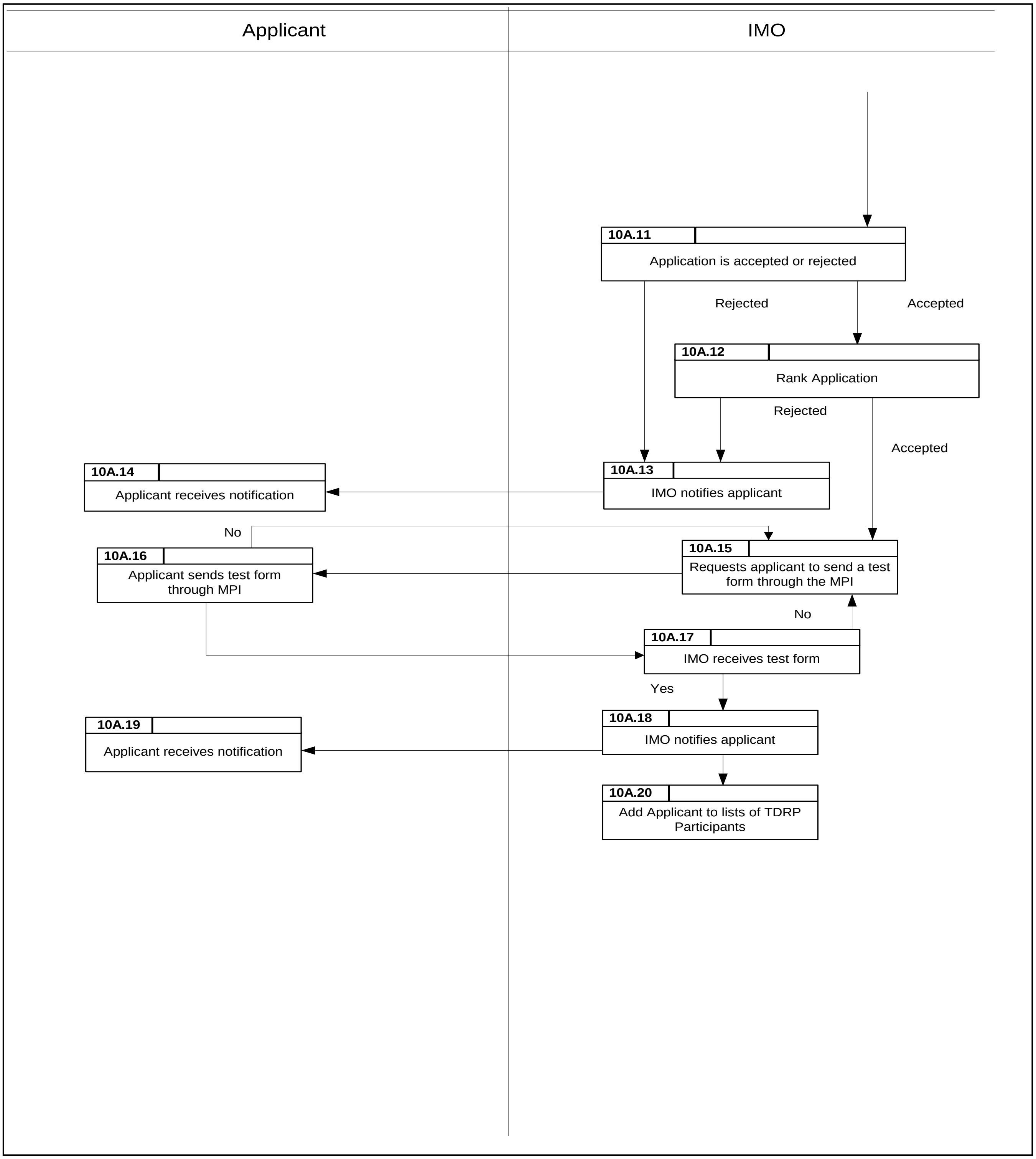

Figure 2–2: Work Flow for TDRP Application Process (continued)

2.2 TDRP Notice of Intent to Provide Demand Response

When the three-hour ahead pre-dispatch price reaches the trigger price of $120/MWh, accepted program participants who wish to participate in the TDRP, must notify the *IMO* of their intent to provide demand response at least two hours prior to the start of the trading hour. The steps in the following diagram describe the process to notify the *IMO* of the program participant's intent to participate in the TDRP in a given trading hour.

Notice must be submitted for each hour in which the participant wishes to participate.

Figure 2-3 is described in detail in Section 3.2, Table 3-2.

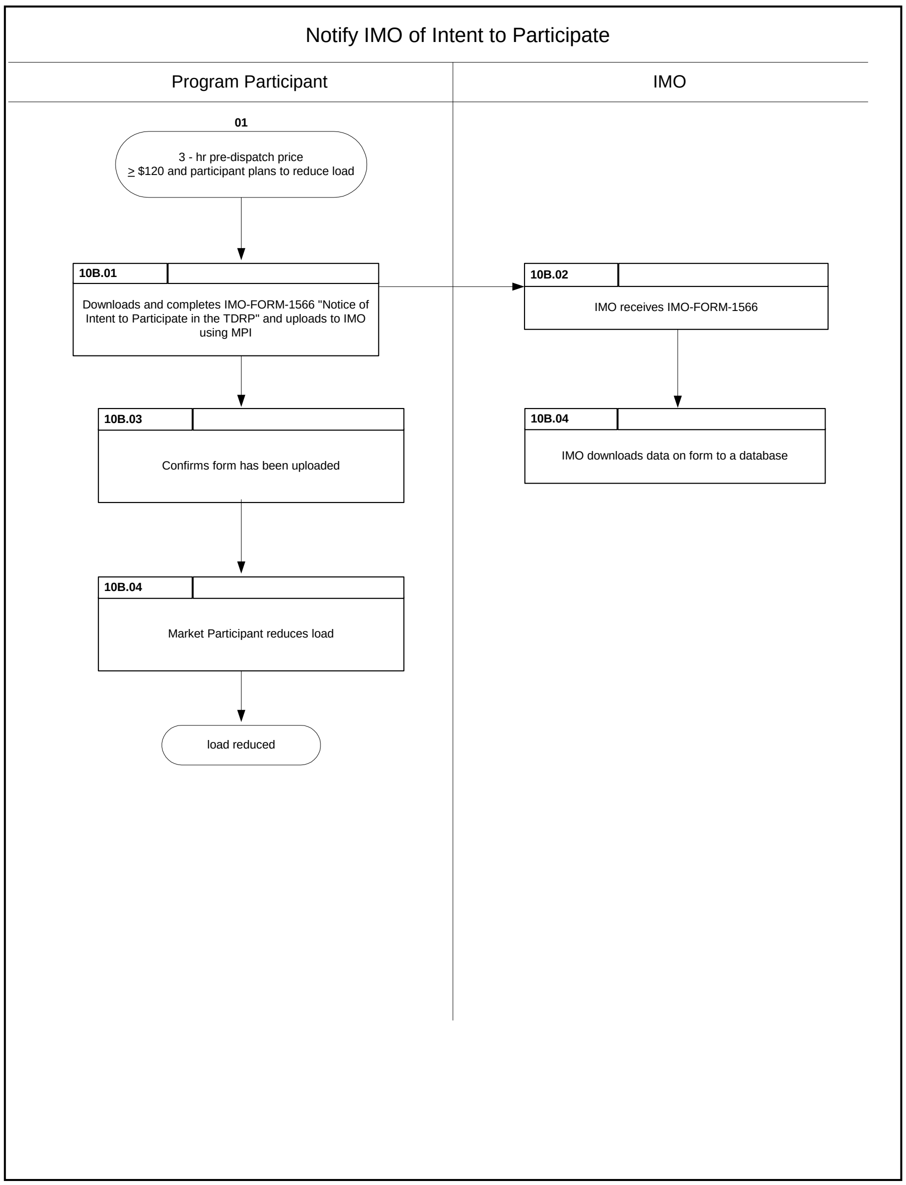

Figure 2–3: Work Flow for TDRP Participation Process

2.3 TDRP *Settlement Process*

Within four *business days* after the last *trading day* of the month following the month in which the demand response was provided, TDRP participants must submit *settlement* data to the *IMO* in order to receive a payment. The steps in the following diagram describe the process to submit *settlement* data to the *IMO*. Figure 2-4 is described in detail in Section 3.3, Table 3-3.

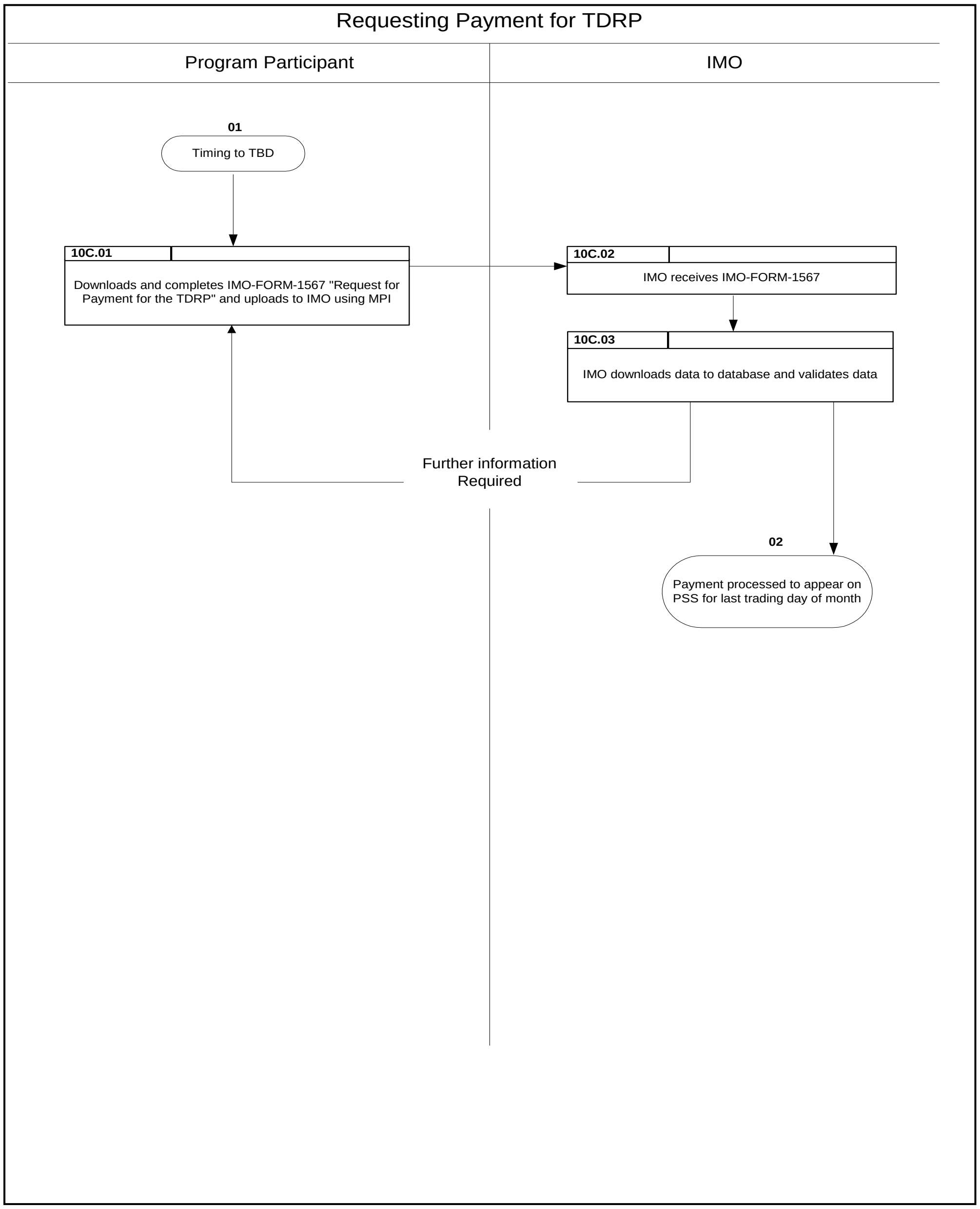

Figure 2–4: Work Flow for TDRP *Settlement Process*

– End of Section –

3. Procedural Steps

This section contains detail on the tasks (steps) that comprise the Transitional Demand Response Program. The steps in the following table are illustrated in Section 2.

The table contains seven columns, as follows:

Ref.

The numerical reference to the task.

Task Name

The task name as identified in Section 2.

Task Detail

Detail about the task.

When

A list of all the events that can trigger commencement of the task.

Resulting Information

A list of the information flows that may or must result from the task.

Method

The format and method for each information flow are specified.

Completion Events

A list of all the circumstances in which the task should be deemed finished.

3.1 TDRP Application Process

Market participants and other potential program participants must apply to participate in the TDRP. The steps shown in the following table are illustrated in Section 2.1, Figures 2-1 and 2-2.

Table 3–1: Procedural Steps for TDRP Application Process

Ref.	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
10A.01	Download, complete and submit IMO-Form-1565.	Applicant downloads "Transitional Demand Response Program Application Form" (IMO-FORM-1565) from *IMO* Web site. The applicant completes the form and assembles any required supporting documents and submits it to the *IMO*.	Prior to deadline for applications.	Applicant has applied to participate in the TDRP.	Mail, courier, fax	Application form submitted.
10A.02	Receive and acknowledge receipt of application form.	*IMO* receives application and supporting documents and send an email acknowledging receipt.	After Step 10A.01	Acknowledgement of receipt of application.	Email	Applicant receives acknowledgement.
10A.03	Process and review application.	*IMO* reviews application. If additional information is required participant is notified.	After Step 10A.02	Application to participate in the TDRP.	Email	Request for information received.

Table 3–1: Procedural Steps for TDRP Application Process

Ref.	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
10A.04	Applicant supplies additional information.	Applicant supplies additional information.	After Step 10A.03 if required.	Additional information to complete application.	Email, fax or mail	Information received.
10A.05 to 10A.07	Determine if applicant is an authorized *market participant*.	*IMO* determines if applicant is an authorized *market participant*. If applicant is not a *market participant*, the *IMO* will refer them to the applicable process documents to become authorized.[1]	After Step10A.03			Authorized *market participant*.
10A.08 to 10A.11	Review applications.	The *IMO* will review the application against the eligibility criteria. If additional information is required, the *IMO* may request that the applicant provide additional information.	After Step 10A.05	Any additional information requested has been received.	Telephone, fax, email	Complete application for review.
				Applications not meeting the eligibility requirements will be rejected and the applicant notified.		Applicants to be notified that application has been rejected.
				Those meeting the requirements will be ranked.		Application ready for ranking.
10A.12	Rank applications.	The *IMO* will rank applications meeting the eligibility requirements.	After Step 10A.08	Applications to be accepted for the TDRP.[1]		Applications to be accepted.
				Applications not accepted for the TDRP.		Applications to be rejected.
10A.13	Notify applicant.	The *IMO* will notify applicants whose applications have not been accepted.	After Step 10A.08 or 10A.12	Notification that application has not been accepted for the TDRP.	Fax and Mail	Applicant receives notification.

[1] An Application to Participate in the TDRP can be conditionally accepted by the IMO pending the authorization of the Applicant to participate in the IMO administered markets.

Table 3–1: Procedural Steps for TDRP Application Process

Ref.	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
10A.14	Applicant receives notification.	The applicant receives notification that application to participate in TDRP has not been accepted.			Fax and Mail	
10A.15	Test form submission using MPI.	The *IMO* will notify the applicant that pending successful upload of test form using MPI application for TDRP has been accepted.	After Step 10A.12 and when applicant is authorized to participate in the *IMO administered markets*.	Applicant notified that application has been accepted pending successful upload of test form.	Fax	
10A.16	Applicant performs test to upload test form using MPI.	Applicant uploads test form using MPI and *IMO* receives form.	After Step 10A.15	Participant can upload forms using MPI.	Uploaded to the MPI	Test to upload test form using MPI was successfully completed.
10A.17	*IMO* receives test form.					Test to upload test form using MPI was successfully completed.
10A.18	Notify applicant.	*IMO* notifies participant that application has been accepted and can now participate in TDRP.	After Step 10A. 16	Participant accepted in TDRP.	Fax and Mail	Participant receives notification. Ready to participate in the TDRP.
10A.19	Applicant receives notification.					Participant receives notification. Ready to participate in the TDRP.
10A.20	Participant added to list of TDRP participants.	*IMO* adds participant to list of accepted participants for the TDRP and files updated list.	After Step 10A.18	Updated internal list of TDRP participants.		

3.2 TDRP Notice of Intent to Provide Demand Response

TDRP participants must submit notice for each hour in which they wish to participate. The steps shown in the following table are illustrated in Section 2.2, Figure 2-3.

Simulation of uploading procedure can be found at:

http:/www.theimo.com/imoweb/marketplaceTraining/systemSims.asp.

Table 3–2: Procedural Steps for TDRP Participation Process

Ref.	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
10B.01	Download and complete, and submit form.	Program participant downloads IMO-FORM-1566, “Notice of Intent to Participate in the TDRP”. Participant completes form and submits to *IMO* by uploading to the MPI.	Participant has been accepted by the *IMO* to participate in the TDRP. 3-hour ahead pre-dispatch price reaches $120.	Notification of intent to provide demand response.	Uploaded to the MPI	Form submitted
10B.02	*IMO* receives form.	IMO-FORM-1566, “Notice of Intent to Participate in the TDRP” has been successfully uploaded using MPI.	After Step 10B.01	*IMO* has notification of program participant’s intent to provide demand response.		Form received.
10B.03	Program participant confirms receipt of form.	Program participant views list of uploaded documents and confirms notification has been uploaded.	After Step 10B.01	*IMO* has notification of program participant’s intent to provide demand response.		Confirmation of notification.
10B.04	Notification data downloaded to database.	*IMO* downloads notification data to database for use in *Settlement process*.	After Step 10B.02	Notification data.		Database updated.
10B.05	Participant reduces					Load reduced

Table 3–2: Procedural Steps for TDRP Participation Process

	load.					

3.3 TDRP *Settlement Process*

TDRP participants must submit *settlement* data to the *IMO* in order to receive a payment. The steps shown in the following table are illustrated in Section 2.3, Figure 2-4.

Simulation of uploading procedure can be found at:

http:/www.theimo.com/imoweb/marketplaceTraining/systemSims.asp.

Table 3–3: Procedural Steps for *Settlement* of the TDRP

Ref.	Task Name	Task Detail	When	Resulting Information	Method	Completion Events
10C.01	Download, and submit form.	Program participant downloads IMO-FORM-1567, "Request for Payment for the TDRP"	No later than 4 *business days* after the last *trading day* of the month following the month in which the demand response was provided	*Settlement* information	Excel spreadsheet uploaded to the MPI	*IMO* receives form
10C.02	*IMO* receives IMO-FORM-1567					
10C.03	*IMO* downloads and validates *settlement* data	*IMO* downloads *settlement* data provided in IMO-FORM-1567, "Request for Payment for the TDRP" *IMO* will validate 3-hour ahead pre-dispatch price,	After Step 10C.01	Validated *settlement* data. *Settlement amount* will appear as a manual line entry (*Charge Type* 134 – Demand Response Credit) on the *settlement statement* for the month	Telephone, email and MPI	*Settlement* ready data

Table 3–3: Procedural Steps for *Settlement* of the TDRP

		confirm notification was received as per Sec. 3.2, review claimed demand response quantity based on baseline data submitted on form. If information is missing or additional information required *IMO* will request participant submit information and provide date by which information is required.		following the month in which the demand response was provided		

– End of Section –

Appendix A: Forms

This appendix contains a list of the forms associated with the Transitional Demand Response Program. These are available on the *IMO* public Web site in the same location as this procedure. The forms included are as follows:

Form Name	Form Number
Transitional Demand Response Program Application Form	IMO-FORM-1565
Notice of Intent to Participate in the Transitional Demand Response Program	IMO-FORM-1566
Request for Payment for Transitional Demand Response Program	IMO-FORM-1567

– End of Section –

Appendix B: Project Eligibility Criteria

1. Participation Must Overcome a Barrier to DR

Participation in the TDRP must help participants to overcome one or more barriers to becoming more demand responsive. The primary barriers are:

- DR is not economic or the benefits are too uncertain
- Existing *market rule*s or regulations impede provision of DR
- There is a lack of infrastructure to enable DR
- Lack of awareness of potential to provide DR

Each of these barriers and the specific information sought from applicants related to these barriers are discussed below.

Proposed DR is not economic without the expected payments from the TDRP

Applicants should substantiate any claim that the proposed DR is not economic without participating in the TDRP. Submissions should include details of the applicant's economic analysis related to the proposed DR, including:

- the capital investment (if any) required for provision of DR
- the internal costs (if any) incurred for the provision of DR (e.g. one-time upfront costs or ongoing per-dispatch costs)
- the expected benefits accruing from the proposed DR under current market conditions and rules (including avoidance of high *energy* costs). These benefits should also reflect the applicant's assumptions regarding the number and duration of high *energy* cost events and the number of these events that could be captured through the proposed DR.
- the applicant's required financial criteria (e.g. target payback, hurdle rate, etc.) that must be satisfied.

Existing *market rule*s or regulations are an impediment to the provision of DR

Applicants should substantiate any claim that *market rule*s or regulations represent a barrier that participation in the TDRP would help overcome. This should include the following at a minimum:

- reference to specific *market rule*s and / or clauses in a code or regulatory instrument.
- a discussion as to how these rules and / or clauses are an impediment to the provision of DR.
- how participation in the TDRP helps to overcome this impediment.

Applicant does not currently have the necessary infrastructure to provide the proposed DR

Applicants should substantiate any claim that lack of infrastructure is a barrier that participation in the TDRP would help overcome. This would likely include the following at a minimum:

- identification of the required infrastructure needed to allow provision of the proposed DR (this could include control equipment, storage capacity to allow certain processes to be temporarily shut down, integration of automation / control equipment with *market price* information, etc.).
- Inventory of any existing infrastructure available to support the provision of the proposed DR.
- How the required infrastructure would complement and augment the existing infrastructure.

Customers are not aware of opportunities to provide DR or do not understand how to do so

Applicants should substantiate any claim that lack of awareness is a barrier that participation in the TDRP would help overcome.

Applicants proposing to aggregate DR from a group of customers should comment on the current level of awareness among the target customer group and discuss how they will overcome any lack of awareness among these customers. This should include the following at a minimum:

- Description of the specific customers being targeted.
- The specific DR these customers could provide.
- Steps the applicant will take to increase DR awareness among this customer group.

Other Barriers

Applicants may face other barriers to becoming more demand responsive, such as insufficient advance notice of high-priced periods. If so, applicants should provide a description of these other barriers and how participation in the TDRP will help to overcome them in their application.

2. Demand Response Activities Must Be Incremental To Any Current Price Response Activities

Applicants should provide evidence that the proposed DR will be incremental to any current price response activities. For applicants with interval metering, this evidence should include the following at a minimum:

- Derivation of a baseline for each of five days (see IMO_FORM_1565) in which three-hour ahead pre-dispatch price exceeded $120/MWh during periods in the one year period prior to April 16, 2004. This baseline should be developed consistent with the methodology described elsewhere in this document.
- Estimation of current price response activities for each of the five days (derived by subtracting the actual load from the baseline).

Applicants representing customers without interval *meters* should describe the target customer's current behaviour and current price response activities, if any.

3. Demand Response Provided Must be Measurable

Participant's DR will be determined based on the baseline less the actual load during a DR event. The baseline for a *trading hour* on a *business day* will be based on the high ten of past eleven same *trading hours* on *business days* immediately preceding the provision of the DR, excluding any hours in which the three hour-ahead pre-dispatch price was equal to or greater than $120/MWh. For Saturdays or Sundays the baseline will be based on the same *trading hour* in the last five Saturdays or Sundays respectively, excluding any days in which the three hour-ahead pre-dispatch price was equal to or greater than $120/MWh.

A variation to the baseline may be proposed by the applicant in the application to participate and will be evaluated by the *IMO* on a case by case basis. Acceptance of the variation will be solely at the discretion of the *IMO*. An example of an acceptable variation might include but not be limited to vacation or maintenance shut downs. The *IMO* will allow applicants to propose the use of a weather correction adjustment to their baseline calculation methodology. Applicants proposing the use of a weather correction adjustment in their baseline calculation in situations where the inclusion of such an adjustment would materially improve the accuracy of the baseline should provide rationale for and details of their proposed adjustment in their application. The *IMO* expects that the number of cooling (or heating) degree days and possibly the relative humidity at a nearby weather station for which data is publicly available would be appropriate input(s) for any weather correction adjustment, but applicants are free to propose alternative weather correction adjustments. Note that it is the *IMO's* intention that any weather correction adjustment should yield unique adjustment factors for each hour of the day even if the weather data upon which the adjustment is based is a daily average (such as cooling degree days). Hence, for any given day the weather correction adjustment for the hour starting at 10 am EST would be different than the weather correction adjustment for the hour starting at 3 pm (EST). Applicants wishing to include a weather correction adjustment in the baseline calculation methodology should compare and contrast 1) the estimated baseline (without weather correction) versus actual load against 2) the adjusted baseline (with weather correction adjustment) versus actual load. Allowance for a weather correction adjustment and selection of the adjustment mechanism will be at the *IMO's* sole discretion.

Measurement and Verification Protocol for Non-Interval Metered Load

Applicants proposing to include DR from non-interval metered loads must provide a proposed measurement and verification (M&V) protocol with their application. Guidelines for development of the M&V protocol are provided in Appendix C. The guidelines were developed by ISO-NE and adapted from its Load Response Manual with ISO-NE's permission.

4. Must Provide Assurance that Proposed DR Will Endure Beyond the Program Period

Applicants must provide assurance that 1) the supporting infrastructure and equipment will remain in place and 2) the proposed DR will extend beyond the duration of the TDRP. Applicants should:

- discuss whether or not the proposed DR capacity would continue following the expiration of the TDRP absent any other changes in *market rule*s, regulatory codes or rate structures
- Estimate the amount and availability, if any, of DR capacity that would be available after the TDRP ends (and absent any changes in *market rule*s, regulatory codes or rates structures) relative to that which would be provided under the TDRP.
- Identify the specific changes in *market rule*s, regulatory codes or rate structures under which the DR would be permanent.

– End of Section –

Appendix C: Measurement and Verification Protocol Development[1]

The following materials were developed by ISO-NE and adapted from its Load Response Program Manual, with ISO-NE's permission.

The guidelines in this Appendix provide an opportunity for Applicants with customers without *facility*-wide interval metering to participate in the TDRP. Applicants must have the ability to cause their customers' electrical loads to be curtailed during a TDRP event and report back their customers' aggregated DR. Examples of potential DR strategies could include:

- Traditional direct load control, such as air-conditioner and electric hot water heater cycling and pool pump reductions
- Permission-based control of thermostat set-points
- Control of lighting circuits and dimmable ballasts
- Compressor controls on vending machines and refrigeration

Applicants have several options for measuring and submitting *energy* usage or load reduction data.

Developing an Acceptable Measurement and Verification (M&V) Plan

The objective of the Applicant's M&V Plan is to describe both the data acquisition procedure and the analysis methodology that will be used by the Applicant to determine their customers' aggregate DR. While unique issues may require attention on a case-by-case basis, all M&V Plans should address the following general issues.

Description of the load reduction measures

The M&V Plan should describe the nature of the load reduction measures, including the type of end-use equipment involved and the manner in which load will be controlled by the Applicant. It should also characterize the nature of the loads under control, with respect to factors such as whether the loads are constant, staged, or continuously variable; are weather or time-dependent; or have interactive effects on other loads. To verify the nature of load characteristics, some short-term monitoring may be necessary and the data included with the submittal of the M&V Plan.

- A constant load device is one that operates at the same demand (kW) whenever it is on, such as a bank of fluorescent lights controlled by a single switch or a single-speed compressor in a packaged air conditioner unit. Since demand is rarely perfectly constant, a load can be considered as constant if it varies by no more than 5-10% from its average value during operation.

- A staged load is one that can operate at several fixed demand levels, such as a two-speed compressor in a packaged air conditioning unit.
- A continuously variable load can operate at any demand within some range – for example, a fan or pump motor with flow controls or a variable speed drive.

The M&V Plan should identify the specifications for each piece of end-use equipment affected by the load reduction strategy at each customer site. Relevant information may include the equipment capacity (kW, tons, horsepower, full-load amps, power factor, etc.), operating schedule, and customer controls (manual operation, *energy* management system, etc.).

Measurement and Monitoring Strategy

The measurement and monitoring activities proposed for calculating *energy* usage or load reduction are a central component of the M&V Plan, and the following set of issues should be addressed.

1. Monitored Parameter(s). At least three general options can be considered:

   a. *Facility*-wide metering of demand (kW). This is the traditional approach allowed in load response programs in which load reductions are estimated based on the whole-premise interval *meters*. This approach is preferred if whole-premise interval metering already exists at a *facility*. However, this approach may not be appropriate if the curtailed loads are small relative to the total *facility* load due to the small "signal-to-noise ratio" or if installing whole-premise interval metering is not economic relative to other monitoring methods.

   b. End-use interval metering of demand (kW). This approach may be more appropriate than Option (a) if curtailed loads are small relative to the building load, a *facility* does not currently have whole-premise interval metering or if end-use demand (kW) data can be readily obtained from a building *energy* management or control's system. However, consideration must be given to the possibility of interactive effects that may significantly alter loads on other end-use equipment. For example, control of dimmable ballasts may lead to higher use of task lighting. Therefore, M&V plans that propose end-use metering must describe why whole-premise interval metering is either not cost-effective or inappropriate.

   c. End-use interval metering of a proxy variable for demand. This method may include measuring something other than demand (kW) such as current (amperage) and voltage or equipment status (on/off, operating time). This approach is characterized by similar attributes as Option (b), but also requires that a correlation be established between the monitored proxy variable and demand (kW). These correlations may be established by conducting short-term monitoring or a series of spot measurements of both parameters, and correlating the data sets (e.g., by performing a regression analysis) to estimate the functional relationship between the two parameters. Alternatively, engineering estimates of this relationship or use of equipment manufacturer's data may be appropriate in some circumstances. For example, current and voltage measurements together with a power factor estimate an end-use's demand (kW). Similar to (b) above, M&V Plans that propose end-use metering of a proxy variable must describe why whole-premise interval metering is either not cost effective or inappropriate.

2. Monitoring Interval and Period. The M&V Plan should specify the period over which monitoring will be conducted and the interval over which monitored values will be averaged, recorded and reported to IMO.

3. Instrumentation. The M&V Plan should identify the type of monitoring and data logging equipment (i.e. manufacturer and model number) to be used, and its accuracy, as indicated by calibration or manufacturer's data. All meters specified must be Measurement Canada approved.

   If alternative methods of measuring demand are proposed (i.e. proxy variables, voltage, current, etc.) the calculated demand (kW) values from the monitoring data should achieve an accuracy of ±2% on the calculated demand (kW).

   If the proposed methods rely on the measured current (amps) and the nominal voltage, the power factor of the end-uses must be included in the demand (kW) calculations. Furthermore, demand measurements for three-phase devices should be conducted on all phases in order to account for any phase imbalance.

   If a *facility*'s *energy* management system (EMS) will be used to record pulse output from a power transducer, the processing accuracy of the EMS must be verified.

4. Sampling. If sampling will be conducted, the M&V Plan should define each population to be sampled, the sample size, and the target level of precision and confidence. The M&V Plan should include all calculations conducted for determining the sample size and describe how the sample points will be selected. For additional information on sampling, refer to the section below titled "Sampling."

Load Reduction Calculation Methodology

The M&V Plan must describe how the Applicant will calculate their DR from the monitored data of individual end-use devices or customers. The Applicant must use the customer baseline methodology described elsewhere in the TDRP rules.

Calculating load reductions from a sample

If *energy* usage or load reductions will be measured for the entire population of controlled loads or customers, then the Applicant's aggregated *energy* usage or load reduction in each measurement interval and zone will be calculated as the sum of all individual measured *energy* usage or load reductions. However, if sampling will be conducted, the Applicant's aggregated *energy* usage or load reduction in each measurement interval and zone must be calculated from the monitoring data of the sample, and the M&V Plan should describe how this calculation will be performed.

The calculation methodology will take one of two general forms:

1. *Energy* usage or load reductions will be determined for each member of the sample and extrapolated to the population in terms of some average normalized value, such as the average kW reduction per unit, per ton of cooling capacity, per kW of connected load, or some other analogous unit.
2. A proxy variable for *energy* usage or load reduction (e.g., change in duty cycle) is determined for each member of the sample, and the *energy* usage or load reduction for the entire population is calculated based on the average measured value of the proxy variable and additional stipulated or measured input parameters for each member of the population (e.g., connected load).

A variety of other critical issues that relate to calculating *energy* usage or load reductions from a sample may also arise and should be addressed in the M&V Plan, including equipment failure and customer over-rides. For control technologies that allow the Applicant to determine over-ride rates and signal failures, better accuracy is possible using these known rates and applying them to the savings for those with successful signal and no over-ride. For example, some thermostat control technologies allow the Applicant to know the signal failure and override for all members of the population. In this case, by separating out all members of the sample with signal failures or overrides, the variation in measured load reduction for the remaining sample points will be generally smaller than it would if the load reduction were calculated for the entire sample. The average load reduction for this subset of the sample can then be extrapolated to the portion of the population that had no signal failure or customer override.

Sampling

If sampling will be conducted, the M&V Plan must define each population to be sampled, the sample size, and the target level of precision and confidence. The M&V Plan must include all calculations conducted for determining the sample size and describe how the sample points will be selected.

Applicants using a Sampling Plan are likely to employ load reduction strategies that involve curtailing similar types of small loads dispersed across a large number of customer sites (e.g., cycling of residential air conditioners) or within a single customer *facility* (e.g., lighting circuits or vending machines). In some cases, it may not be feasible for the Applicant to individually monitor each piece of equipment, and it may be appropriate to monitor a representative sample. To do so, the Applicant must first identify the relevant populations and then determine the appropriate sample size for each population. After monitoring has been conducted, the Applicant must evaluate the distribution of their sample in order to recalculate their sample size for the following year.

Identifying the Relevant Populations

To monitor a sample of end points, the Applicant must first identify populations whose members (e.g., end-use devices, customers, lighting circuits) would be expected to have similar values for the monitored parameter. If the populations are defined too broadly, the sample will be unlikely to provide statistically significant results. Populations should consist of members that are similar with respect to:

1. Type and size of equipment affected by the load reduction strategy;
2. Usage patterns (e.g., residential vs. commercial); and
3. Load control strategy (e.g., duty cycle control vs. thermostat set point control).

Determining the Appropriate Sample Size

The appropriate sample size depends on the target level of precision at some specified confidence interval. For all programs, the default statistical target is 90/10 (10% precision at a one-tailed 90% confidence level) in the load reduction (kW) amount.

A generally accepted methodology for calculating the appropriate sample size is to conduct simple random sampling for each population. To follow this approach, first calculate the sample size corresponding to an infinite population (n'), according to Equation (1):

$$n' = \left(\frac{z \times c.v.}{p} \right)^2 \qquad (1)$$

Where z is the z-factor for a given confidence interval (z = 1.282 for a one-tailed 90% confidence interval); p is the precision (p = 0.1 for 10% precision); and c.v. is the coefficient of variation, which is equal to the ratio of the standard deviation of the sampled variable to its average value. In general, the greater the expected variation in the variable from one device to the next – e.g., due to operational patterns or equipment size – the greater the value of c.v. that should be used to calculate the sample size. If monitoring has already been conducted, the c.v. should be based on the monitored data. Otherwise, a default initial value of c.v. = 0.5 should be used. For load reductions that are likely to have significant variations from one device to the next, a larger c.v. may be necessary.

The sample size (n) for the finite population (N) can then be calculated according to Equation (2):

$$n = \frac{n'}{1 + {}^{n'}\!/_{N}} \qquad (2)$$

Where n is rounded up to the nearest integer.

If an Applicant has multiple populations, as an alternative they may calculate sample sizes based on a stratified sampling approach, applied across all of the populations. This technique involves more complex sample size calculations, but will generally yield a smaller total number of sample points.

If the Applicant believes that the sample sizes corresponding to a 90/10 statistical target would result in onerous M&V costs relative to project benefits, they may propose a reduction in sample sizes. However, the *IMO* will then de-rate the Applicant's DR. To determine the level of de-rating, first calculate the precision at 90% confidence associated with the reduced sample size, according to Equation (3):

$$p = z \times c.v. \times \sqrt{\frac{{}^{N}\!/_{n} - 1}{N}} \qquad (3)$$

The de-rating of load reductions is based on the difference between this precision and the target level of 10%. For example, if the precision associated with a reduced sample size is 15%, load reductions will be de-rated by 15%-10% = 5%.

For any sample calculation methodology, it is advisable that the Applicants over-sample (e.g., by 10%) to compensate for potential data loss due to failures in monitoring equipment or other factors.

Evaluating the Sample Distribution Based on Monitoring Data

During the first year of participation a default value for the coefficient of variation (c.v.) will be set to 0.5. However, after some TDRP events, the Applicant can more accurately estimate the c.v. of the population, based on the monitoring data for these events. For simple random sampling, the procedure for evaluating the c.v. of each population is as follows:

1. For each hour of each load reduction event, calculate the mean value and standard deviation of the sampling variable (e.g., kW reduction per unit).
2. Based on the hourly standard deviation and mean values, calculate hourly values for the c.v., equal to the ratio of the standard deviation to the mean.
3. Calculate the average of the hourly c.v. values for all reduction events during the calendar year.

Based on these calculated c.v. values, the Applicant can re-calculate the appropriate sample size for the following program year, using Equations (1) and (2). If the calculated c.v. values are significantly larger than 0.5, this could indicate either that the population has a wide distribution with respect to the sampling variable, or that the population is composed of two or more distinct groups that should be disaggregated into separate populations. In the latter case, the Applicant should re-calculate the c.v. values for each separate population, based on the existing sample data from each of these groups.

M&V Plan Checklist

Applicants may wish to consult the following checklist to ensure that their M&V Plan addresses the necessary issues and contains adequate detail.

1. The M&V Plan describes the load reduction strategy and related end-use devices, identifying:
   - The type, quantity, and location of end-use devices that will be controlled
   - The manner in which end-use devices will be controlled
   - The general characteristics of the end-use devices, with respect to factors such as load variability, time- or weather-dependence, and interactive effects on other end-use equipment
   - Detailed specifications, to the extent possible, for each end-use device to be controlled, including nameplate capacity, operating schedule, and customer controls
2. The M&V Plan describes the measurements that will be conducted to calculate DR during TDRP events, identifying:
   - The parameters that will be measured
   - The duration over which monitoring will be conducted
   - The interval over which monitoring data will be averaged and recorded
   - The type of monitoring and data logging equipment to be used and their accuracy (include calibration data and/or manufacturer's spec sheets to verify instrumentation accuracy)
   - If applicable, the populations to be sampled, the target level of precision and confidence, and the sample sizes (include all calculations used to determine sample size)
3. The M&V Plan describes the methodology by which aggregate DR for each hour will be calculated from the monitoring data, identifying:
   - How the actual load will be calculated, for M&V strategies that involves the measurement of proxy variables
   - How the baseline load will be calculated, including the period used to calculate baseline loads and adjustments that will be made to account for weather or time of day
   - If sampling will be conducted, the calculation method by which monitored results from the sample will be applied to the entire population, including (if applicable) the effect of customer over-rides and signal or equipment failure

Template – TDRP Monitoring & Verification Plan

1.0 Measurement and Monitoring Strategy

1.1 Monitoring Parameters and Variables

1.2 Monitoring Interval and Period

1.3 Measurement Equipment Specifications

1.4 Measurement Data Collection and Management Plan

1.4.1 Measurement Data Validation, Editing and Estimating Plan

2.0 Statistical Sampling Plan

2.1 Description of Population(s)

2.2 Sample Size Calculations

2.3 Method of Sampling

3.0 Demand Reduction Calculation Methodology

– End of Section –

References

Document Name	Document ID

– End of Document –

UNDERTAKING J3.2

IESO UNDERTAKING J3.2

UNDERTAKING

To calculate a reserve margin for 2023, if the forecast 4,000-plus capacity gap is not reached

RESPONSE

The TCA is intended to assist the IESO to meet its minimum reliability requirements in accordance with NERC reliability standards. If the IESO did not obtain the approximately 4,000-plus megawatts required to meet the 2023 capacity gap through the TCA or any other means the resulting 2023 reserve margin would be approximately -5% and the IESO would not be able to meet the forecast 2023 demand.

UNDERTAKING J3.3

IESO UNDERTAKING J3.3

UNDERTAKING

To provide Reliability Outlook

RESPONSE

The most recent Reliability Outlook is attached.

Reliability Outlook

An adequacy assessment of Ontario's electricity system

FROM OCTOBER 2019 TO MARCH 2021

Connecting Today.
Powering Tomorrow.

Executive Summary

The fall edition of the IESO's Reliability Outlook provides the sector with a big-picture energy overview for the 18-month period from October 2019 to March 2021. This analysis aims to help market participants schedule their outages, while drawing attention to considerations that could affect the reliability of Ontario's electricity system.

Energy demand remains stable

Not much has changed significantly in the three months since the summer Outlook was released. For 10 years, the demand for energy from the grid has remained fairly stable in Ontario, and 2019 is expected to wrap with a small decline in demand. In 2020, a strong U.S. economy, a low Canadian dollar and all the associated economic activity, are foreseen to spur increased demand.

Resources are ready and adequate

The Outlook determined that, under normal conditions, Ontario is well-positioned to meet the demand for electricity over the 18-month forecast period. Any risks arising during this time should be sufficiently managed through rescheduling outages.

Outage requests may face increasing pressure

Coordinating outages is increasingly challenging as significant capital upgrades often coincide with ongoing routine maintenance. Considering firm resources and extreme weather, Ontario's reserve above requirement (RAR) is projected to fall below the 2,000 MW threshold for several weeks in summer 2020. If these conditions materialize, the IESO may need to reject some outage requests during this period. The anticipated completion date for the Darlington Unit 2 refurbishment has been delayed until mid-2020. If the project is pushed back further into the summer, managing outages could become an even greater challenge.

The Independent Electricity System Operator (IESO) ensures the reliability of Ontario's power system on behalf of all Ontarians. Balancing electricity supply and demand depends on comprehensive short- and long-term planning that enables the IESO to continue to meet reliability requirements, while giving market participants the data and insights they need to make informed operational and investment decisions.

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1. Introduction

This Outlook covers the 18-month period from October 2019 to March 2021, which supersedes the Outlook released on June 20, 2019.

The purpose of the 18-month horizon in the *Reliability Outlook* is to:

- Advise market participants of the resource and transmission reliability of Ontario's electricity system
- Assess potentially adverse conditions that might be avoided by adjusting or coordinating maintenance plans for generation and transmission equipment
- Report on initiatives being implemented to improve reliability within this time frame

Additional supporting documents are located on the IESO website.

This Outlook presents an assessment of resource and transmission adequacy based on the stated assumptions, using the methodology described in the accompanying methodology document. Due to uncertainties associated with the assumptions used in this analysis, readers must exercise judgment in applying this information to possible future scenarios.

Security and adequacy assessments are published daily on the IESO website and progressively supersede the information presented in this report.

For questions or comments on this Outlook, please contact us by:

- Telephone: 1-888-448-7777 or 905-403-6900
- E-mail: customer.relations@ieso.ca

2. Updates to This Outlook

2.1 Updates to Demand Forecast

The demand forecast used in this Outlook is informed by actual demand, weather and economic data through to the end of June 2019, and has been updated to reflect the most recent economic projections. Actual weather and demand data for July and August 2019 are included in the tables.

2.2 Updates to Resources

This *Reliability Outlook* considers planned generator outages submitted by market participants to the IESO's outage management system as of September 9, 2019.

2.3 Updates to Transmission Outlook

Transmission outage plans that were submitted to the IESO's outage management system by July 29, 2019, are considered in this Outlook.

2.4 Updates to Operability Outlook

The outlook for surplus baseload generation (SBG) conditions over the next 18 months is based on generator outage plans submitted by market participants to the IESO's outage management system as of September 9, 2019.

3. Demand Forecast for 18-Month Period

Grid-supplied energy demand is expected to dip in 2019, as some of the weakness in the latter half of 2018 carried over into 2019. For 2020 and early 2021, demand is expected to see positive gains beyond the bump that comes with the additional day of a leap year. Continued economic and demographic growth will push demand higher.

The IESO is responsible for forecasting electricity demand on the IESO-controlled grid. This demand forecast covers the period from October 2019 to March 2021 and supersedes the previous forecast released in June 2019. Tables of supporting information are contained in the 2019 Q3 Outlook Tables spreadsheet.

Electricity demand is shaped by a number of factors. These can:

- Increase the demand for electricity, e.g., population growth, economic expansion and the increased penetration of end-uses
- Reduce the need for grid-supplied electricity, e.g., conservation and embedded generation
- Shift demand, e.g., time-of-use rates and the Industrial Conservation Initiative (ICI)

How each of these factors impacts electricity consumption varies by season and time of day – and is reflected in the demand forecast.

Grid-supplied energy demand has been fairly flat since the 2009 recession with small increases and decreases year-to-year. Based on the actuals to date, a small decline is expected in 2019. Going forward, a strong U.S. economy and low Canadian dollar will help boost demand in the industrial sector, while population growth and consumer activity should help increase electricity demand in the residential and commercial markets. These combined effects, along with the additional leap year day, will lead to positive growth in 2020. As well, embedded generation capacity has stopped growing and conservation savings are forecast until the end of 2020, eliminating downward pressure on electricity demand later in the forecast.

Peak demands are subject to the same forces as energy demand, though the impacts vary. This is true when comparing energy demand to peak demand, and summer to winter peaks. Recent history has seen lower summer peaks, thanks to growth in embedded-generation capacity and the ICI. The majority of embedded generation is provided by solar-powered facilities that generate high output during traditional summer peak-hour periods and no output during the winter peak-hour periods. In addition to reducing summer peaks, higher embedded solar output has also pushed the peak to later in the day. As before, with the amount of embedded solar capacity plateauing and no incremental conservation savings beyond 2020, the downward pressure on peaks is forecast to ease, allowing for an overall increase in the demand forecast.

The following tables show the seasonal peaks and annual energy demand over the forecast horizon of the Outlook.

Table 3-1 | Historical and Forecast Energy Summary

Year	Normal Weather Energy (TWh)	% Growth in Energy
2006	152.3	-1.9%
2007	151.6	-0.5%
2008	148.9	-1.8%
2009	140.4	-5.7%
2010	142.1	1.2%
2011	141.2	-0.6%
2012	141.3	0.1%
2013	140.5	-0.6%
2014	138.9	-1.1%
2015	136.2	-1.9%
2016	136.2	0.0%
2017	132.3	-2.8%
2018	135.2	2.2%
2019 (Forecast)	134.9	-0.2%
2020 (Forecast)	135.9	0.7%

Table 3-2 | Forecasted Seasonal Peaks

Season	Normal Weather Peak (MW)	Extreme Weather Peak (MW)
Winter 2019-20	21,115	22,288
Summer 2020	22,138	24,500
Winter 2020-21	21,160	22,456

3.1 Actual Weather and Demand

Since the last forecast, actual electricity demand and weather data for June, July and August have been recorded.

June

- In June, the weather was much colder than normal, with average temperatures putting it in the coldest quartile of the past 50 years. The peak temperature for the month was also in the coldest quartile.

- The monthly peak occurred on Thursday, June 27, the hottest day of the month. The afternoon high was 28.9°C (at Toronto), the coolest June peak since 2015, when the June peak (19,339 MW) was the lowest since market opening.
- The weather-corrected peak for the month was 21,043 MW. This is consistent with the past several years where the weather-corrected peak has averaged 21,200 MW since the 2009 recession.
- Energy demand for the month was 10.4 TWh (10.5 TWh weather-corrected), lower than the last several years which averaged roughly 11.0 TWh weather-corrected.
- The minimum demand for the month was 10,564 MW, in line with June values since the 2009 recession. The minimum occurred in the early hours of Sunday, June 9.
- Embedded generation for the month was 602 GWh, an increase of 0.1% compared to the previous June. Hydro (27.6%) and non-contracted (94.4%) output were up, but reductions in solar (-9.1%) and bio (-6.5%) output offset those increases.
- Wholesale customer consumption increased 0.9% year over year. Most of the growth came from petroleum refining (45.2%) and chemicals (2.6%). Other major sectors were flat.

July

- This year, the weather was warmer than normal for July. The warmer weather didn't occur during peak periods, but instead over the remainder of the month when the weather is usually cooler. The peak temperature was the 18th highest over the past 50 years, but the average temperature was the 7th highest.
- The peak occurred on July 29, the third warmest day of the month, during a modest heat wave. The peak-day high was 31.4°C, which was slightly warmer than normal. The actual peak was 21,791 MW (21,069 MW weather-corrected). The observed July peak was the fourth-lowest since market opening.
- Similar to last July, energy demand for the month was 12.7 TWh (12.3 TWh weather-corrected)
- Minimum demand was 11,565 MW – a high value by recent historical standards – and occurred in the early morning of the Canada Day holiday.
- Embedded generation for July topped 607 GWh, which represents a 20.1% increase over last July. Bio-gas output was down slightly (-1.3%) over the previous July, while all other types increased – solar (2.4%), wind (12.6%) and hydro (24.2%).
- Wholesale customer load fell 0.4% year over year. While iron and steel (4.5%) rebounded with the removal of U.S. tariffs, and petroleum refining (0.3%) and chemicals (4.3%) continued to perform strongly, declines in pulp and paper (-9.3%) and other sectors brought the numbers down for the month.

August

- This year, the weather for August was near normal. Although average temperatures were representative, peak temperatures were cooler than normal and minimum temperatures were higher than normal. This means that energy demand was typical but peak demand was low. The peak temperature was the 45th highest over the past 50 years, while the average temperature was the 26th highest.

- Peak demand occurred on August 21, which was the hottest day of the month and came at the end of a moderate heat wave. The peak-day high was 30.2°C, which was cooler than normal. The actual peak was 21,354 MW (22,100 MW weather-corrected).
- Without the high temperatures of last year, actual demand was 11.8 TWh, much lower than last year's 12.7 TWh. With near normal average temperatures, the weather-corrected value was also 11.8 TWh.
- Minimum demand of 11,280 MW and occurred in the early morning of the Sunday, August 11.
- Embedded generation for August topped 557 GWh, representing a 6.7% increase over last August. Increases in wind (28.5%) and hydro (39.0%) output more than offset the decline in solar (-4.9%) and bio-gas (-5.5%) output.
- Wholesale customer load fell slightly (-0.1%) in August. Pulp and paper (-9.3%) and iron and steel (-8.6%) showed declines that outweighed growth in mining (10.4%) and chemicals (3.1%). Wholesale customer load continues to bounce around without a clear and sustained pattern.

Overall, energy demand for the three summer months from June to August was down 3.6% compared with the previous summer. After adjusting for the weather, demand for the three months showed a decline of 2.0%.

Embedded generation for the three months increased by 8.5% over the same time a year ago. Most of the increase came from wind and hydro generation.

For the three months, wholesale customer consumption posted a 0.1% decrease over the same months a year prior. Pulp and paper and iron and steel showed declines where the other large sectors – mining, refining, chemicals and motor vehicle production showed an increase.

The 2019 Q3 Outlook Tables spreadsheet contains several tables with historical data. They are:

- Table 3.3.1 Weekly Weather and Demand History Since Market Opening
- Table 3.3.2 Monthly Weather and Demand History Since Market Opening
- Table 3.3.3 Monthly Demand Data by Market Participant Role

Table 3-3 | Weekly Energy and Peak Demand Forecast

Week Ending	Normal Peak (MW)	Extreme Peak (MW)	Load Forecast Uncertainty (MW)	Normal Energy Demand (GWh)
06-Oct-19	17,091	17,334	786	2,398
13-Oct-19	16,936	16,952	507	2,422
20-Oct-19	17,186	17,593	392	2,377
27-Oct-19	17,365	17,843	318	2,460
03-Nov-19	17,559	18,193	416	2,477
10-Nov-19	18,521	18,946	601	2,573
17-Nov-19	18,717	19,533	342	2,591
24-Nov-19	19,318	20,022	607	2,678
01-Dec-19	19,597	20,619	409	2,708
08-Dec-19	19,924	21,033	555	2,754
15-Dec-19	20,307	21,173	690	2,791
22-Dec-19	20,086	21,165	362	2,782
29-Dec-19	18,512	19,560	528	2,626
05-Jan-20	19,859	20,856	570	2,755
12-Jan-20	21,115	22,288	547	2,913
19-Jan-20	20,694	21,320	483	2,889
26-Jan-20	20,548	21,502	404	2,889
02-Feb-20	20,573	21,658	734	2,905
09-Feb-20	19,853	21,449	635	2,841
16-Feb-20	19,490	20,841	581	2,773
23-Feb-20	19,245	20,903	501	2,740
01-Mar-20	19,764	20,956	531	2,784
08-Mar-20	19,318	20,091	649	2,716
15-Mar-20	18,214	18,867	611	2,628
22-Mar-20	17,543	18,448	569	2,532
29-Mar-20	17,526	18,494	567	2,529
05-Apr-20	17,257	17,811	471	2,487
12-Apr-20	16,616	17,485	496	2,375
19-Apr-20	15,985	16,142	531	2,358
26-Apr-20	16,179	16,715	721	2,353
03-May-20	17,207	19,509	849	2,335
10-May-20	16,497	19,247	845	2,340
17-May-20	18,002	21,097	1,175	2,361
24-May-20	17,648	21,341	1,330	2,313
31-May-20	18,482	20,800	1,292	2,376
07-Jun-20	19,209	23,331	1,055	2,550
14-Jun-20	20,278	23,723	835	2,567
21-Jun-20	21,347	23,789	754	2,630

Week Ending	Normal Peak (MW)	Extreme Peak (MW)	Load Forecast Uncertainty (MW)	Normal Energy Demand (GWh)
28-Jun-20	21,477	23,793	1,016	2,686
05-Jul-20	20,481	23,246	814	2,646
12-Jul-20	22,138	24,500	838	2,749
19-Jul-20	20,683	23,994	1,035	2,620
26-Jul-20	21,232	24,194	841	2,710
02-Aug-20	21,890	24,042	958	2,707
09-Aug-20	21,234	23,634	985	2,673
16-Aug-20	20,478	23,450	1,362	2,655
23-Aug-20	21,320	23,094	1,413	2,702
30-Aug-20	19,926	22,346	1,370	2,550
06-Sep-20	18,330	23,143	680	2,442
13-Sep-20	18,788	20,493	781	2,417
20-Sep-20	17,556	19,734	420	2,422
27-Sep-20	16,783	18,057	554	2,362
04-Oct-20	17,109	17,141	786	2,407
11-Oct-20	16,746	16,794	507	2,424
18-Oct-20	17,042	17,451	392	2,384
25-Oct-20	17,225	17,720	318	2,468
01-Nov-20	17,477	18,111	416	2,495
08-Nov-20	18,470	18,796	601	2,576
15-Nov-20	18,617	19,332	342	2,596
22-Nov-20	19,168	19,851	607	2,668
29-Nov-20	19,583	21,044	409	2,730
06-Dec-20	19,880	20,889	555	2,757
13-Dec-20	20,271	21,240	690	2,798
20-Dec-20	19,991	21,070	362	2,785
27-Dec-20	18,740	19,587	528	2,742
03-Jan-21	20,182	21,072	528	2,731
10-Jan-21	21,160	22,456	570	2,938
17-Jan-21	20,826	21,752	547	2,909
24-Jan-21	20,680	21,836	483	2,909
31-Jan-21	20,704	21,987	404	2,933
07-Feb-21	20,179	21,577	734	2,860
14-Feb-21	19,815	21,164	635	2,792
21-Feb-21	19,571	21,230	581	2,759
28-Feb-21	20,108	21,294	501	2,811
07-Mar-21	19,670	20,244	531	2,744
14-Mar-21	19,009	19,465	649	2,674
21-Mar-21	17,866	18,567	611	2,551

Week Ending	Normal Peak (MW)	Extreme Peak (MW)	Load Forecast Uncertainty (MW)	Normal Energy Demand (GWh)
28-Mar-21	17,850	18,614	569	2,548
04-Apr-21	17,877	18,207	567	2,474

3.2 Forecast Drivers

3.2.1 Economic Outlook

Economic fundamentals remain generally positive for the Ontario economy. Strong U.S. growth, a low Canadian dollar and low interest rates are conducive to growth in Ontario's export-oriented, energy-intensive manufacturing sector. The economy will continue to face significant downside risk during the forecast period due to trade tensions, climate impacts, and global political uncertainty. As long as these risks do not materialize, Ontario should experience increasing economic output over the forecast period. Table 3.3.4 of the 2019 Q3 Outlook Tables presents the economic assumptions for the demand forecast.

3.2.2 Weather Scenarios

The IESO uses weather scenarios to produce demand forecasts. These scenarios include normal and extreme weather, along with load forecast uncertainty, which is a measure of uncertainty in demand due to weather volatility. Table 3.3.5 of the 2019 Q3 Outlook Tables presents the weekly weather data for the forecast period.

3.2.3 Demand Measures and Load Modifiers

Both demand measures and load modifiers can impact demand but differ in how they are treated within the Outlook. Demand measures are not incorporated into the demand forecast and are instead treated as resources. Load modifiers are incorporated into the demand forecast.

As demand measures are dispatched like generation resources, they are included in the supply mix, and added back into the history when forecasting demand. Therefore, the impacts of demand measures are not included in the demand forecast.

Load modifiers include conservation (energy-efficiency programs, codes and standards and fuel switching), price impacts (time-of-use rates and the Industrial Conservation Initiative), and embedded generation. Each impacts demand differently in terms of level and timing, but together have the net effect of reducing the demand for grid-supplied electricity. Conservation affects both the height of peaks and the energy consumed, prices reduce demand during peak periods, and embedded generation impacts vary by fuel type.

4. Resource Adequacy for 18-Month Period

The IESO expects to have sufficient generation supply for winter 2019/2020 as well as winter 2020/2021. Potential risks in summer 2020 are expected to be mitigated by outage rescheduling and by the capacity that will be acquired in the IESO's upcoming capacity auction. Over the next 18 months, 1,500 MW of new generation are planned to come into service, while approximately 38 MW of generation will reach the end of its contract life.

This section provides an assessment of the adequacy of resources to meet the forecast demand. Resource adequacy is one of the key reliability considerations used for approving outages. When reserves are below required levels, and could adversely affect the reliability of the grid, the IESO will reject outage requests based on their order of precedence. Conversely, when reserves are above required levels, additional outages can be considered, provided other factors, such as local considerations, operability, or transmission security do not pose a reliability concern. In those cases, the IESO may place a planned outage at risk, signaling to the facility owner to consider rescheduling the outage.

The existing installed generation capacity is summarized in Table 4-1. This includes capacity from new projects that have completed the IESO's market registration process since the previous Outlook. The forecast capability at the Outlook peak is based on the firm resource scenario, which includes resources currently under commercial operation, and takes into account deratings, planned outages, and allowance for capability levels below rated installed capacity.

Table 4-1 | Existing Grid-Connected Resource Capacity

Fuel Type	Total Installed Capacity (MW)	Forecast Capability at Outlook Peak (MW)	Number of Stations	Change in Number of Stations	Change in Installed Capacity
Nuclear	13,009	11,258	5	0	0
Hydroelectric	9,065[1]	4,995	76	0	0
Gas/Oil	10,277	8,439	31	0	0
Wind	4,486	611	39	0	0
Biofuel	295	254	7	0	0
Solar	424	58	9	0	0
Demand Measures	-	794	-	-	-
Firm Imports (+) / Exports (-) (MW)	-	0	-	-	-
Total	**37,555**	**26,411**	**167**	**0**	**0**

[1] Hydroelectric installed capacity has been revised upward since the previous outlook due to a change in calculation methodology; there has been no new hydro capacity installed since the last outlook. The effective MW contribution of hydro at peak remains unchanged.

4.1 Assessment Assumptions

4.1.1 Generation Resources

All generation projects that are scheduled to come into service, or to be upgraded or shut down within the Outlook period are summarized in Table 4-2. This includes generation projects in the IESO's connection assessment and approval process (CAA), those under construction, and contracted resources. Details regarding the IESO's CAA process and the status of these projects can be found on the Application Status section of the IESO website.

The Estimated Effective Date column in Table 4-2 indicates the best estimated date of the completion of market registration available to the IESO as of September 9, 2019.

Two scenarios are used to describe project risks.

- The **planned scenario** assumes that all resources scheduled to come into service are available over the assessment period.
- The **firm scenario** assumes resources are restricted to those that have achieved commercial operation status.

Planned shutdowns or retirements of generators that have a high certainty of occurring in the future are considered in both scenarios.

Table 4-2 | Committed Generation Resources Status

Project Name	Zone	Fuel Type	Estimated Effective Date	Project Status	Capacity Considered Firm (MW)	Capacity Considered Planned (MW)
Loyalist Solar	East	Solar	2019-Q4	Commissioning	0	54
Henvey Inlet Wind Farm	Essa	Wind	2020-Q1	Commissioning	0	300
Napanee Generating Station	East	Gas	2020-Q1	Under Development	0	985
Nation Rise	East	Wind	2020-Q1	Under Development	0	100
Romney Wind Energy Centre	West	Wind	2020-Q1	Under Development	0	60
Calstock	Northeast	Biofuel	2020-Q2	Expiring Contract	-38	-38
Total					**-38**	**1,461**

Notes on Table 4-2:

The total may not add up due to rounding and does not include in-service facilities. Project status provides an indication of project progress, using the following terminology:

• Under Development – projects in approvals and permitting stages (e.g., environmental assessment, municipal approvals, IESO connection assessment approvals) and projects under construction.

• Commissioning – projects undergoing commissioning tests with the IESO.

• Commercial Operation – projects that have achieved commercial operation status under the contract criteria, but have not met all of the IESO's market registration requirements.

• Expiring Contract – generators whose contracts expire during the Outlook period are included in both scenarios only up to their contract expiry date. Generators (including non-utility generators) that continue to provide forecast output data are also included in the planned scenario for the rest of the 18-month period.

4.1.2 Generation Capability

Hydroelectric

A monthly forecast of hydroelectric generation output is calculated based on median historical values of hydroelectric production and contribution to operating reserve during weekday peak demand hours. Through this method, routine maintenance and actual forced outages of the generating units are implicitly accounted for in the historical data (see the first row in Table 4-3). To reflect the impact of hydroelectric outages on the reserve above requirement (RAR) and allow the assessment of hydroelectric outages as per the outage approval criteria, the hydroelectric capability without accounting for historical outages is also calculated (see the second row of Table 4-3). Table 4-3 uses data from May 2002 to March 2019, which are updated annually to coincide with the release of the Q2 Outlook.

Table 4-3 | Monthly Historical Hydroelectric Median Values for Normal Weather Conditions

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Historical Hydroelectric Median Contribution (MW)	6,338	6,276	6,102	6,035	6,139	5,958	5,876	5,522	5,273	5,643	5,882	6,336
Historical Hydroelectric Median Contribution without Outages (MW)	6,851	6,846	6,609	6,555	6,594	6,465	6,270	6,047	6,104	6,449	6,616	6,846

Thermal Generators

Thermal generators' capacity, planned outages and deratings are based on market participant submissions. Forced outage rates on demand are calculated by the IESO based on actual operations data. The IESO will continue to rely on market participant-submitted forced-outage rates for comparison purposes.

Wind

For wind generation, monthly wind capacity contribution (WCC) values are used at the time of weekday peak. The specifics on wind contribution methodology can be found in the Methodology to Perform the Reliability Outlook. Figure 4-1 shows the monthly WCC values, which are updated annually to coincide with the release of the Q2 Outlook.

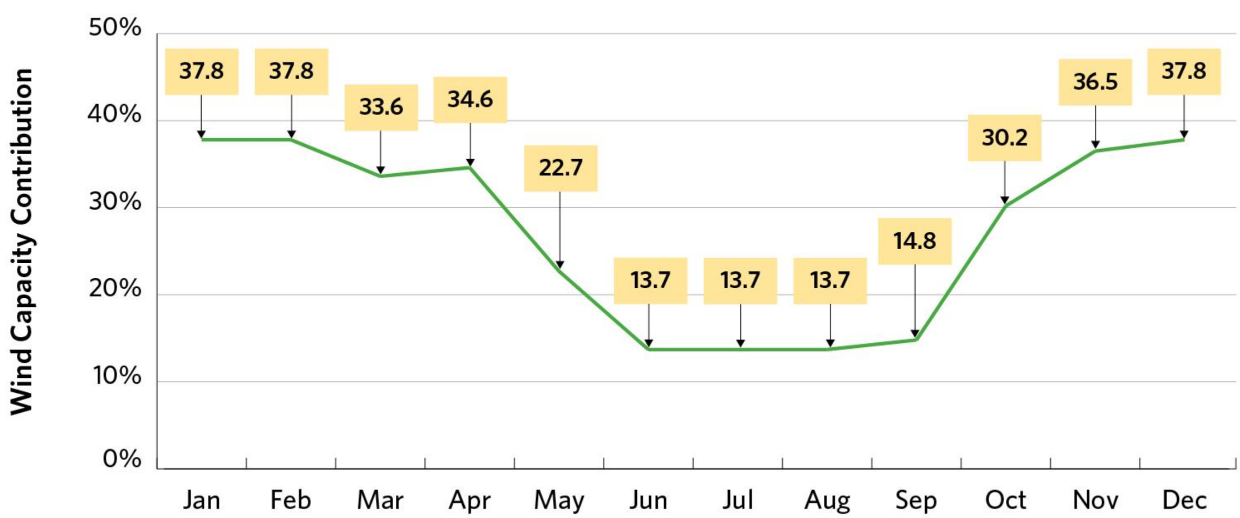

Figure 4-1 | Monthly Wind Capacity Contribution Values

Solar

For solar generation, monthly solar capacity contribution (SCC) values are used at the time of weekday peak. The specifics on solar contribution methodology can be found in the Methodology to Perform the Reliability Outlook. Figure 4-2 shows the monthly SCC values, which are updated annually to coincide with the release of the Q2 Outlook.

Due to the increasing penetration of embedded solar generation, the grid demand profile has been changing, with summer peaks being pushed to later in the day. As a consequence, the contribution of grid-connected solar resources at the time of peak Ontario demand has declined.

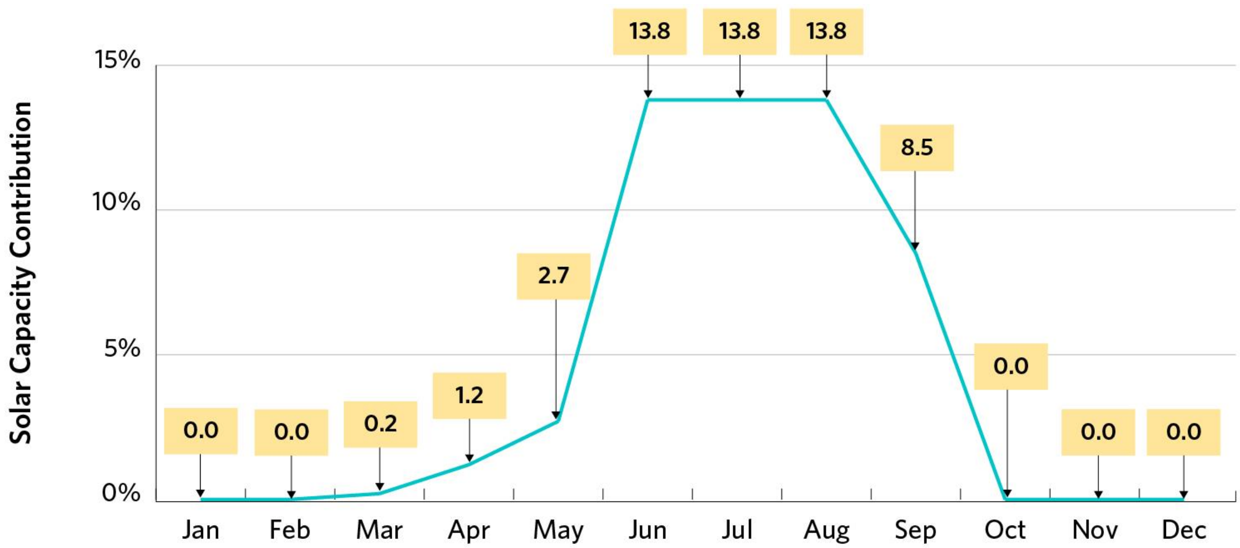

Figure 4-2 | Monthly Solar Capacity Contribution Values

4.1.3 Demand Measures

Both demand measures and load modifiers can have an impact on demand, but they differ in how they are treated within the Outlook. Demand measures, such as dispatchable loads and demand response procured through the IESO's capacity auction, are not incorporated into the demand forecast and are instead treated as resources. Load modifiers are incorporated into the demand forecast, as explained in 3.2.3 (Demand Measures and Load Modifiers). The impacts of actual activations of demand measures are added back into the demand history prior to forecasting demand for future periods.

4.1.4 Firm Transactions

Capacity-Backed Exports

The IESO allows Ontario resources to compete in the capacity auctions of some neighbouring jurisdictions, provided Ontario is adequately supplied. Capacity-backed exports of up to 128 MW of installed capacity were successful in the New York Independent System Operator (NYISO) auctions for delivery between May and October 2019.

System-Backed Exports

As part of the electricity trade agreement between Ontario and Quebec, Ontario will supply 500 MW of capacity to Quebec each winter from December to March until 2023. In addition, Ontario will receive up to 2.3 TWh of clean energy annually, scheduled economically via Ontario's real-time markets. The imported energy will target peak hours to help reduce greenhouse gas emissions in Ontario. The agreement includes the opportunity to cycle energy.

As part of this capacity-exchange agreement, Ontario can call on 500 MW of capacity during summer before September 2030, based on the province's needs.

4.1.5 Summary of Scenario Assumptions

To assess future resource adequacy, the IESO must make assumptions about the amount of available resources. The Outlook considers two scenarios: a firm scenario and a planned scenario, as described in section 4.1.1.

The starting point for both scenarios is the existing installed resources shown in Table 4-1. Generator-planned shutdowns or retirements that have a high certainty of occurring in the future are considered in both scenarios, as are planned outages submitted by generators. Table 4-4 shows a snapshot of the forecast available resources, under the two scenarios in normal weather conditions, at the time of the summer and winter peak demands during the Outlook.

Table 4-4 | Summary of Available Resources under Normal Weather

		Winter Peak 2020		Summer Peak 2020		Winter Peak 2021	
Notes	**Description**	**Firm Scenario**	**Planned Scenario**	**Firm Scenario**	**Planned Scenario**	**Firm Scenario**	**Planned Scenario**
1	Installed Resources (MW)	37,555	37,609	37,555	39,054	37,555	39,054
2	Total Reductions in Resources (MW)	12,257	12,311	11,980	12,490	10,370	10,727
3	Demand Measures (MW)	924	924	794	794	924	924
4	Firm Imports (+) / Exports (-) (MW)	-500	-500	0	0	-500	-500
5	Available Resources (MW)	25,722	25,722	26,369	27,358	27,609	28,751
6	Bottling (MW)	1,996	1,996	42	42	426	426
7	Available Resources without Bottling (MW)	27,718	27,718	26,411	27,400	28,036	29,178

Notes on Table 4-4:

1. Installed Resources: the total generation capacity assumed to be installed at the time of the summer and winter peaks.
2. Total Reductions in Resources: the sum of deratings, planned outages, limitations due to transmission constraints and allowance for capability levels below rated installed capacity.
3. Demand Measures: the amount of demand expected to be available for reduction at the time of peak.
4. Firm Imports/Exports: the amount of expected firm imports and exports at the time of summer and winter peaks.
5. Available Resources: Installed Resources (line 1) minus Total Reductions in Resources (line 2) plus Demand Measures (line 3) and Firm Imports/Exports (line 4). This differs from the Forecast Capability at System Peak shown in Table 4-1 due to the impacts of generation bottling (transmission limitations).
6. Available Resources without Bottling: Available resources after they are reduced due to transmission constraints.

4.2 Capacity Adequacy Assessment

The capacity adequacy assessment accounts for zonal transmission constraints resulting from planned transmission outages assessed as of July 29, 2019. The planned generation outages occurring during this Outlook period have been assessed as of September 9, 2019. Note that the reserve above requirement (RAR) charts shown below reflect changes in the refurbishment schedule for Darlington G2. The return-to-service date has changed from February 2020 to June 2020.

4.2.1 Firm Scenario with Normal and Extreme Weather

The firm scenario incorporates all capacity that had achieved commercial operation status as of September 9, 2019.

Figure 4-3 shows RAR levels, which represent the difference between available resources and required resources. The latter equals the demand plus required reserve. The reserve requirement in the firm scenario under normal weather conditions is met throughout the entire Outlook period.

The IESO's revised outage approval methodology, using the extreme weather scenario with up to 2,000 MW of imports, has been in effect since May 1, 2019. In the extreme weather scenario, the reserve is lower than the requirement for a total of four weeks in 2020. Under the current outage schedule, the RAR is below the

- 2,000 MW threshold for three weeks in June 2020 and one week in September 2020. This potential shortfall is largely attributed to planned generator outages scheduled during those weeks. If extreme weather conditions materialize, the IESO may reject some generator maintenance outage requests to ensure that Ontario demand is met during the summer peak periods.

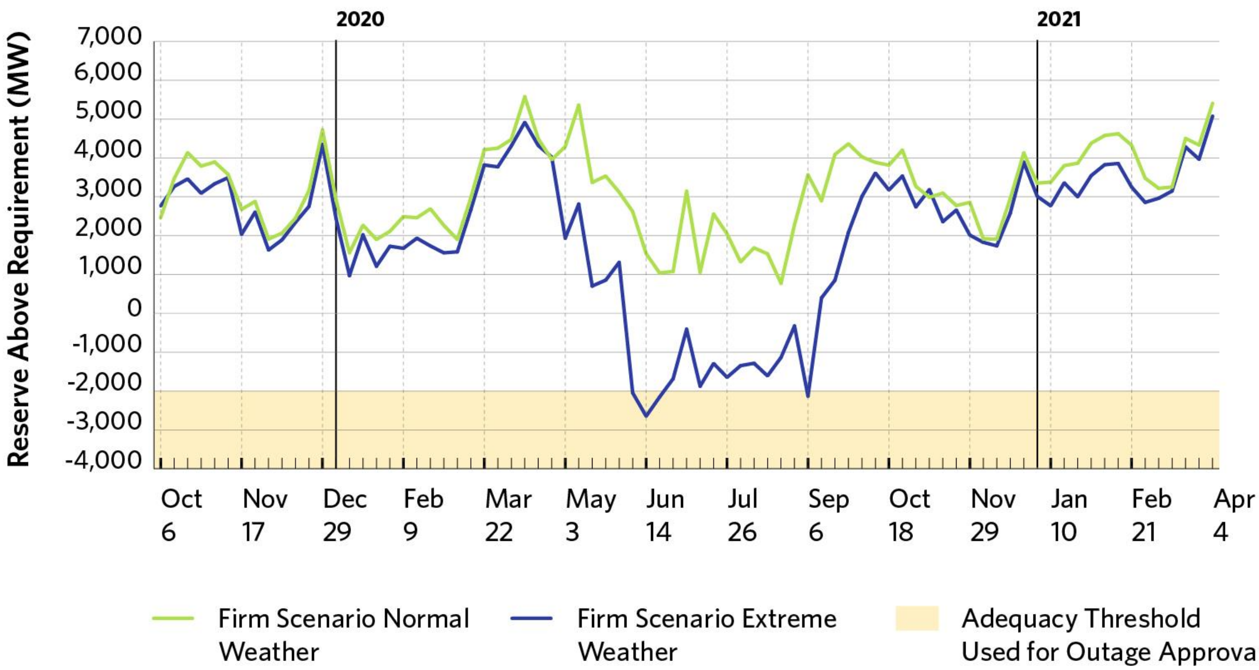

Figure 4-3 | Comparison of Normal and Extreme Weather: Firm Scenario Reserve Above Requirement

4.2.2 Planned Scenario with Normal and Extreme Weather

The planned scenario incorporates all existing capacity plus all capacity coming into service. Figure 4-4 shows RAR levels under the planned scenario, with the reserve requirement being met throughout the Outlook period under normal weather conditions.

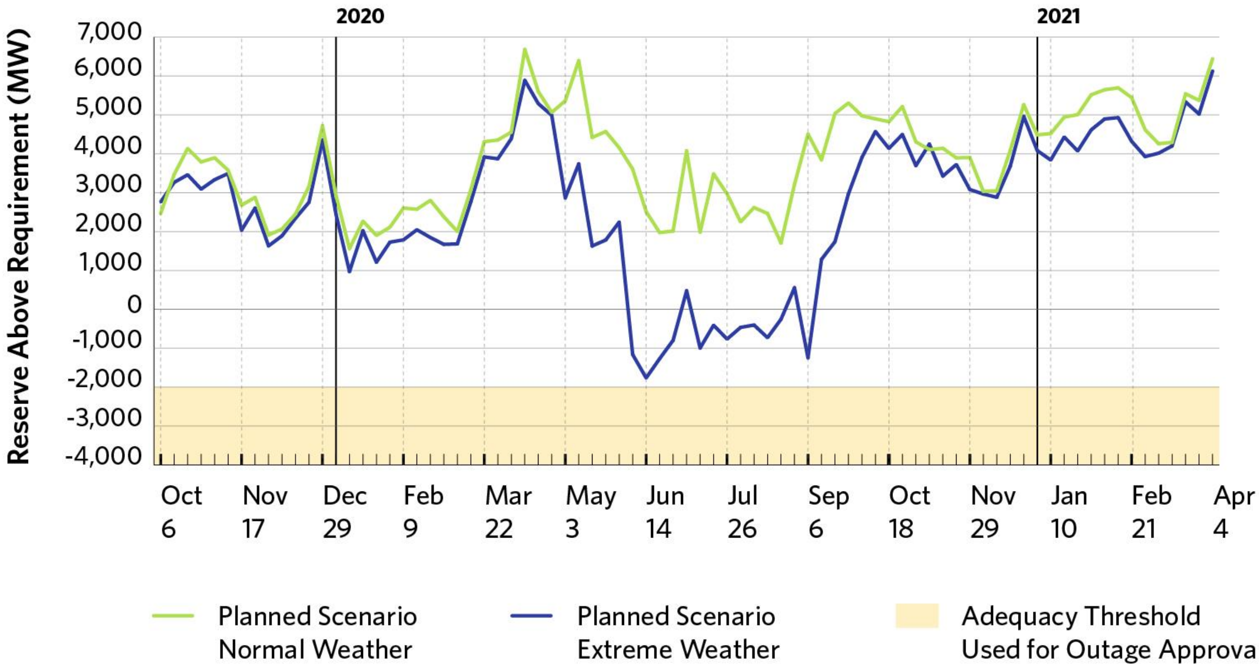

Figure 4-4 | Comparison of Normal and Extreme Weather: Planned Scenario Reserve Above Requirement[2]

4.2.3 Comparison of the Current and Previous Weekly Adequacy Assessments for the Firm Extreme Weather Scenario

Figure 4-5 compares forecast RAR values in the current Outlook with those in the previous Outlook published on June 20, 2019. The difference is primarily due to changes to planned outages and the expected in-service dates of new resources.

[2] Note that the "Planned" scenarios are not used for outage approval, and the adequacy threshold is shown in this chart for illustrative purposes only.

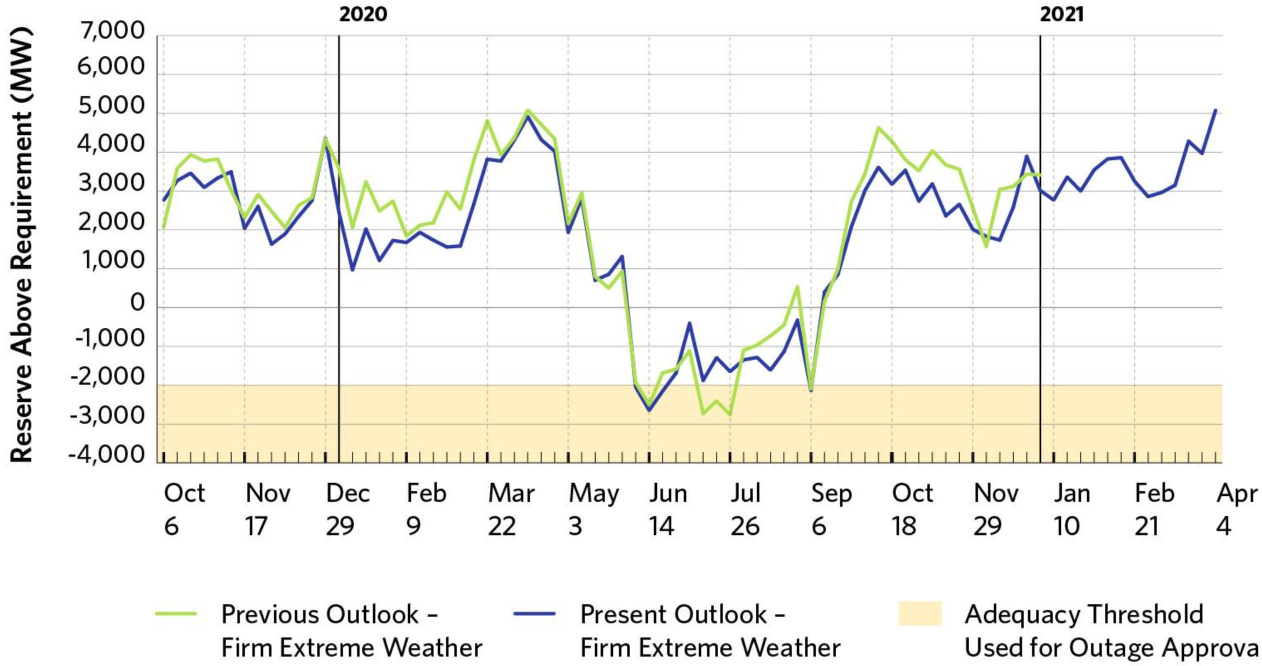

Figure 4-5 | Comparison of Current and Previous Outlook: Firm Scenario Extreme Weather Reserve Above Requirement

Resource adequacy assumptions and risks are discussed in detail in the Methodology to Perform the Reliability Outlook.

4.2.4 Capacity Auction

For this Outlook, the capacity adequacy assessment assumes that existing off-contract resources will continue to be available. The IESO's first capacity auction is expected to begin this December and will enable competition between dispatchable generators with expired contracts and demand response resources for delivery of auction capacity over two obligation periods: summer and winter (beginning May 1, 2020 and November 1, 2020, respectively). The pre-auction report will be published on September 26.

4.3 Energy Adequacy Assessment

This section provides an assessment of energy adequacy to determine whether Ontario has sufficient supply to meet its forecast energy demand and to highlight potential adequacy concerns during the Outlook time frame. The assessment also estimates aggregate production by resource category to meet the projected demand based on the assumed availability of resources.

4.3.1 Summary of Energy Adequacy Assumptions

The energy adequacy assessment (EAA) uses the same set of assumptions as the capacity assessment, as outlined in Table 4-1 and Table 4-2, pertaining to resources expected to be available over the next 18 months. The monthly forecast of energy production capability, based on the energy modelling results, is included in the 2019 Q3 Outlook Tables.

For the EAA, only the firm scenario in Table 4-5 with normal weather demand is considered. The key assumptions specific to this assessment are described in the Methodology to Perform the Reliability Outlook.

4.3.2 Results – Firm Scenario with Normal Weather

Table 4-5 summarizes the energy simulation results over the next 18 months for the firm scenario with normal weather demand for Ontario and each transmission zone.

Table 4-5 | Summary of Zonal Energy for Firm Scenario Normal Weather

	18-Month Energy Demand		18-Month Energy Production		Net Inter-Zonal Energy Transfer	Zonal Energy Demand on Peak Day of 18-Month Period	Available Energy on Peak Day of 18-Month Period
Zone	**TWh**	**Average MW**	**TWh**	**Average MW**	**TWh**	**GWh**	**GWh**
Bruce	1.0	79	65.4	4,970	64.4	1.4	129.6
East	14.0	1,065	13.6	1,032	-0.4	28.9	71.5
Essa	12.1	920	3.5	269	-8.6	24.8	13.6
Niagara	5.8	438	20.2	1,539	14.4	14.0	51.5
Northeast	16.5	1,252	16.1	1,224	-0.4	28.0	37.6
Northwest	6.2	473	7.1	539	0.9	10.1	22.1
Ottawa	15.0	1,144	0.3	20	-14.7	25.2	1.3
Southwest	42.2	3,208	8.8	672	-33.4	92.2	24.1
Toronto	74.6	5,673	57.0	4,337	-17.6	176.7	160.6
West	20.9	1,586	16.2	1,234	-4.7	48.8	74.6
Ontario	**208.3**	**15,837**	**208.3**	**15,837**	**0.0**	**450.1**	**586.5**

4.3.3 Findings and Conclusions

For the firm scenario with normal weather demand, the EAA results indicate that Ontario is expected to have sufficient supply to meet its energy forecast during the next 18 months without support from external jurisdictions. The figures and tables in this section are based on simulation of the province's power system, using the assumptions presented within the Outlook to confirm that Ontario will be energy adequate.

Figure 4-6 breaks down projected production by fuel type to meet Ontario's energy demand for the next 18 months, while Figure 4-7 shows the production by fuel type for each month. The province's energy exports and imports are not considered in this assessment. Table 4-6 summarizes these simulated production results by fuel type, for each year.

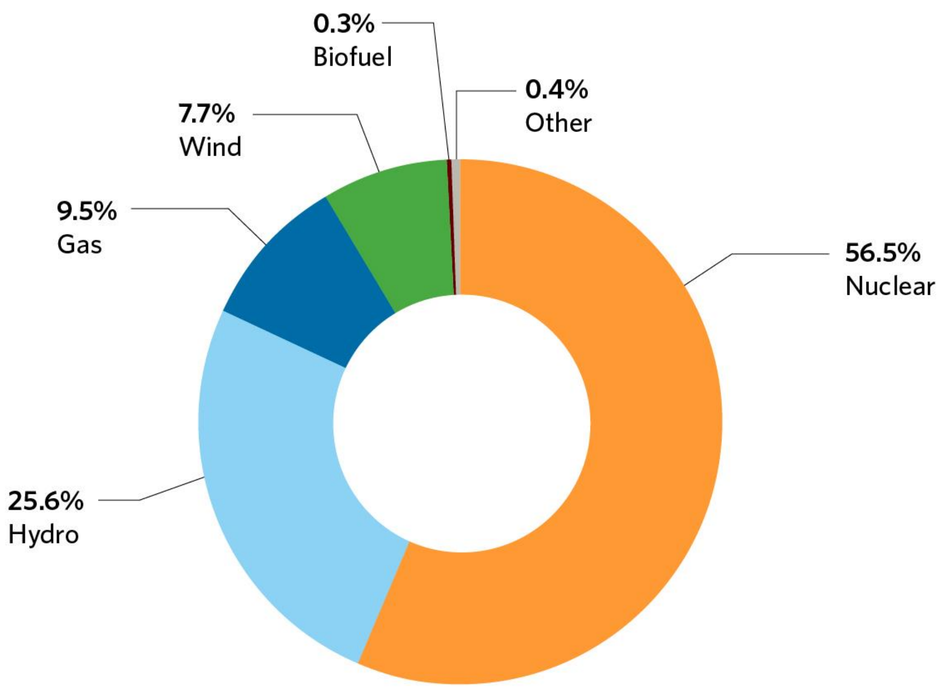

Figure 4-6 | Forecast Energy Production by Fuel Type

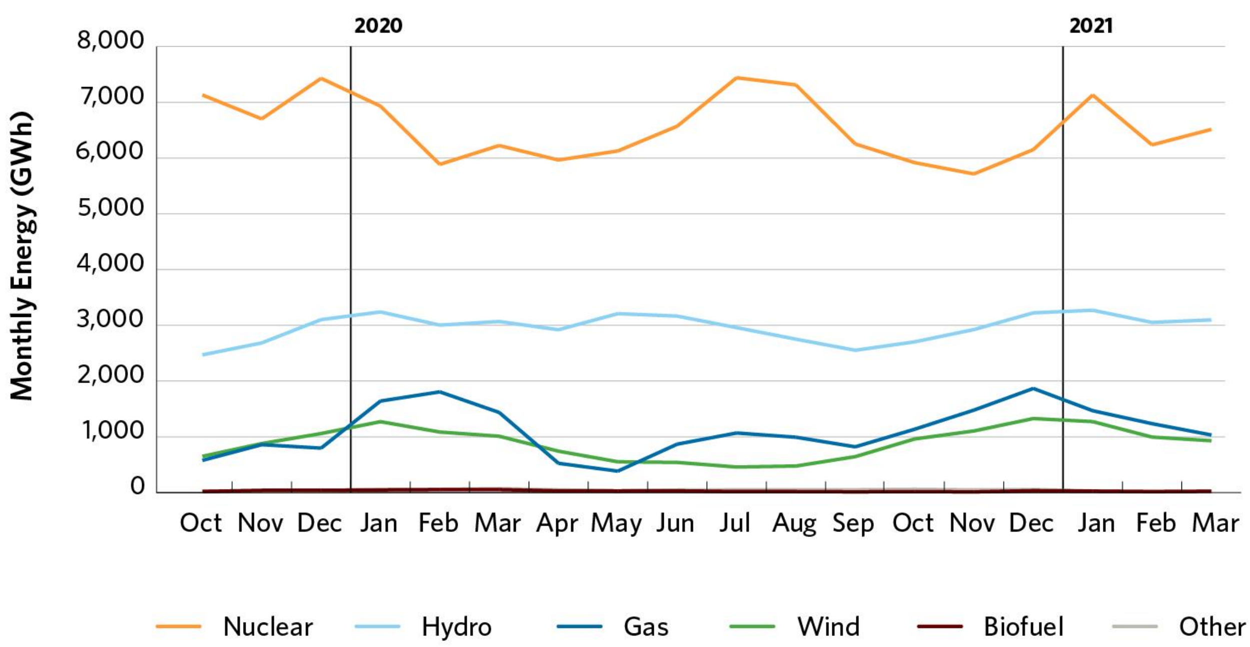

Figure 4-7 | Forecast Monthly Energy Production by Fuel Type

Table 4-6 | Ontario Energy Production by Fuel Type for the Firm Scenario Normal Weather

Fuel Type (Grid Connected)	2019 (Oct 1 - Dec 31) (GWh)	2020 (Jan 1 - Dec 31) (GWh)	2021 (Jan 1 - Mar 31) (GWh)	Total (GWh)
Nuclear	21,263	76,495	19,881	117,639
Hydro	8,256	35,720	9,419	53,396
Gas & Oil	2,234	14,029	3,737	20,000
Wind	2,588	10,177	3,198	15,964
Bio Fuel	101	355	66	523
Other (Solar & DR)	85	613	73	770
Total	**34,528**	**137,389**	**36,374**	**208,291**

5. Transmission Reliability Assessment

Ontario's transmission system is expected to continue to reliably supply province-wide demand, while experiencing normal contingencies defined by planning criteria for the next 18 months. However, some combinations of transmission and/or generation outages could create operating challenges.

The IESO assesses transmission adequacy using a methodology based on conformance to established criteria, including the Ontario Resource and Transmission Assessment Criteria (ORTAC), NERC transmission planning standard TPL 001-4 and NPCC Directory #1 as applicable. Planned system enhancements and known transmission outages are also considered in the studies.

5.1 Transmission Projects

For the purpose of this section, the information that transmitters provide, with respect to transmission projects that are planned for completion within the next 18 months, is considered. The list of transmission projects is provided in Appendix B1.

5.2 Transmission Outages

The IESO's assessment of transmission outage plans is shown in Appendix C, Tables C1 to C11. The methodology used to assess the transmission outage plans is described in the Methodology to Perform the Reliability Outlook. This Outlook contains transmission outage plans submitted to the IESO as of July 29, 2019.

5.3 Transmission Considerations

The purpose of this section is to highlight select projects and outages that may significantly affect the scheduling of other outages and/or may significantly affect reliability (i.e., in terms of limiting transfer capabilities in the system). These considerations are categorized by zone.

Bruce and Southwest Zones

Hydro One’s replacement of aging infrastructure at the Bruce 230 kV switchyard is underway and requires careful coordination of transmission and generation outages. This project is scheduled to be completed by Q2 2021.

A planned three-week outage on circuit B560V starting November 4, 2019 will reduce the transfer capability out of the Bruce Zone.

Niagara Zone

On August 30, 2019 the Niagara Reinforcement Project was completed. This project increases the summertime transfer capability out of the Niagara area to the rest of Ontario by up to 800 MW.

A number of non-contiguous planned outages from September 4, 2019 until November 11, 2019 will impact circuits out of Beck #2 TS, reducing the transfer capability out of the Niagara area during this time.

West Zone

Significant growth in the greenhouse sector has led to a number of customer connection requests in the Windsor-Essex region that are expected to exceed the capacity of the existing transmission system in the area. A new switching station at the Leamington Junction is currently proceeding toward a planned Q4 2022 in-service date. Outages may become more challenging to facilitate starting in late 2019, when new loads are connected and required transmission reinforcements are being implemented.

A planned two-week outage on circuit B569B starting October 5, 2020 will reduce the transfer capability into the West Zone.

Toronto, East and Ottawa Zones

Operational challenges due to high voltages in Eastern Ontario and the Greater Toronto Area continue to occur during periods of low demand. The IESO and Hydro One are currently managing this situation by removing one of the 500 kV circuits in Eastern Ontario during those periods. To address this issue on a longer-term basis, two 500 kV line-connected shunt reactors will be installed at Lennox TS with a target in-service date of Q4 2020 for the first reactor and Q4 2021 for the second reactor.

A number of non-contiguous planned outages impacting circuits E510V and E511V from October to December 2019 will reduce transfer capability north from the Toronto Zone to the Essa Zone.

Northwest and Northeast Zones

Reinforcements to the system in the Kapuskasing area, including upgrades to circuit H9K and installing reactive compensation, are planned for Q1 2020 and Q1 2021 respectively. During the construction of these reinforcements, outages in the area may be restricted.

Multiple outages impacting circuit X504E between September and November 2019 will reduce transfer capability on the North-South Tie.

A planned two-week outage starting November 30, 2019 impacting circuit M23Lwill reduce transfer capability across the East-West Tie.

Interconnections

The early 2018 failure of the phase angle regulator (PAR) connected to the Ontario-New York 230 kV interconnection circuit L33P continues to hinder the province's ability to import from New York through the New York-St. Lawrence interconnection and from Quebec through the Beauharnois interconnection. This has required enhanced coordination with affected parties and more focused management on St. Lawrence area resources in real-time. Careful coordination of transmission and generation outages will be required in the area. PARs are unique pieces of equipment and replacements are not readily available. Replacement options for the unit are currently being investigated jointly with the IESO, Hydro One, NYISO and the New York Power Authority. The preferred replacement option is a new PAR with a +/- 50-degree angle range, based on the recommendation by the joint NY/ON team to Hydro One for tendering. If all goes well, the return to service date for the L33P PAR would be November 2021.

Intermittent planned outages will impact interconnection circuit PA302 from September to November 2019 and will reduce the import and export transfer capacity between Ontario and New York at Niagara ties.

A planned three-week outage starting November 18, 2019 will impact circuit L51D, reducing import and export transfer capability between Ontario and Michigan.

6. Operability

During the Outlook period, Ontario will continue to experience potential surplus baseload conditions, much of which can be managed with existing market mechanisms, such as exports and curtailment of variable generation. Nuclear curtailments may be required in spring and early fall 2020.

This section highlights existing or emerging operability issues that could impact the reliability of Ontario's power system.

6.1 Outage Management Concerns

Market participants are reminded that outage coordination is becoming more challenging as significant capital upgrades are underway such as refurbishment outages, station rebuilds, etc., at the same time as ongoing routine maintenance. The Reliability Outlook informs market participants about critical periods, allowing the market the opportunity to reschedule outages and minimize the risk of outages being revoked by the IESO in the operating timeframe.

6.2 Grid Voltage Control

During low demand periods, including the overnight period, it can be challenging to maintain system voltages within the prescribed limits in certain parts of the system. Increased supply from distribution connected resources results in the displacement of centralized generation facilities and, consequently, in reduced transfers across the transmission system. Lightly loaded lines are a source of reactive power and result in high system voltages. The IESO and Hydro One are currently managing this situation with day-to-day operating procedures and plan to address this issue on a longer-term basis (refer to section 5.3 – Toronto, East and Ottawa Zones).

6.3 Surplus Baseload Generation

Baseload generation is made up of nuclear, run-of-the-river hydroelectric and variable generation, such as wind and solar. When baseload supply is expected to exceed Ontario demand, market signals reflect these conditions through lower prices. Resources and activity at the interties respond accordingly to the prices. The resulting outcomes from the market include higher export schedules, dispatching down of hydroelectric generation and grid-connected renewable resources, and nuclear maneuvering or shutdown. For severe surplus conditions, which may affect reliability of the system, the IESO may take out-of-market actions such as manual curtailments of resources and/or imports. Significant SBG conditions were observed last quarter as a result of lower demand due to cooler weather and minimal nuclear outages. A number of control actions, including nuclear generation manoeuvers and shutdowns were required to manage SBG.

Ontario will continue to experience potential surplus baseload conditions during the Outlook period. Figure 6-1 highlights the periods during which curtailment of nuclear generation may be expected.

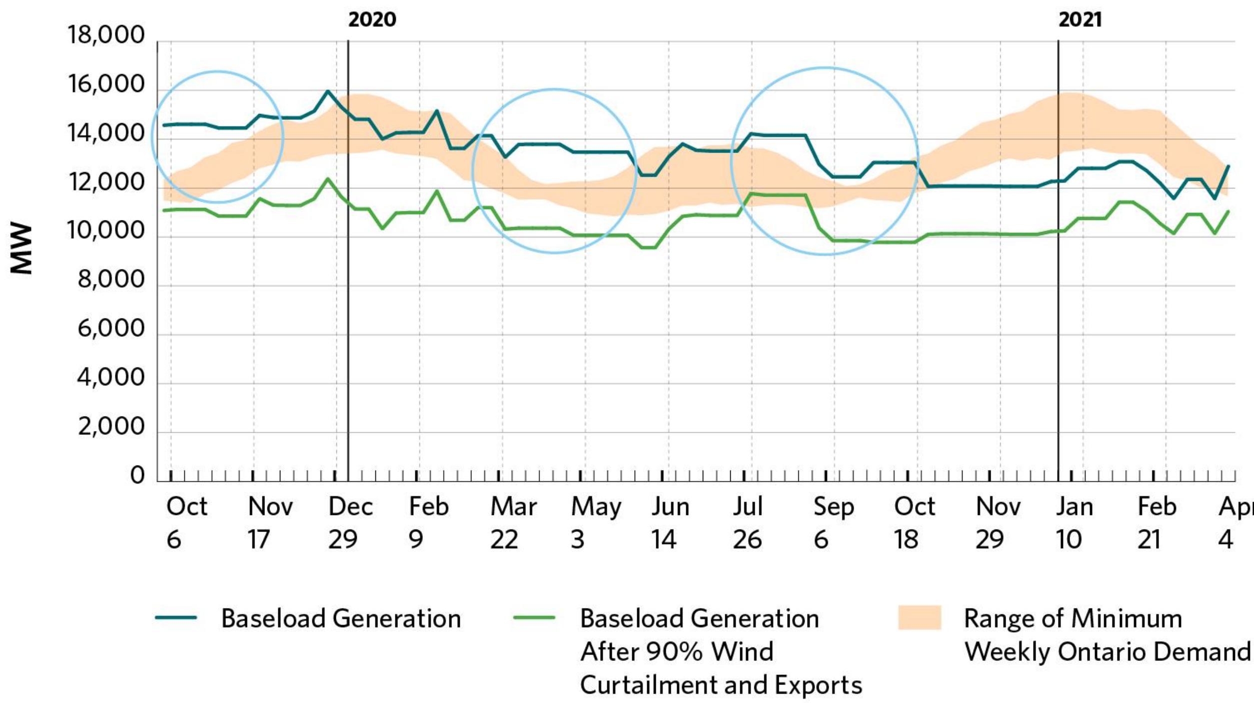

Figure 6-1 | Minimum Ontario Demand and Baseload Generation

Much of the surplus baseload conditions can be managed with existing market mechanisms signaling for exports, and curtailment of variable and nuclear generation. Going forward, as shown in Figure 6-2, existing mechanisms will be sufficient for managing SBG.

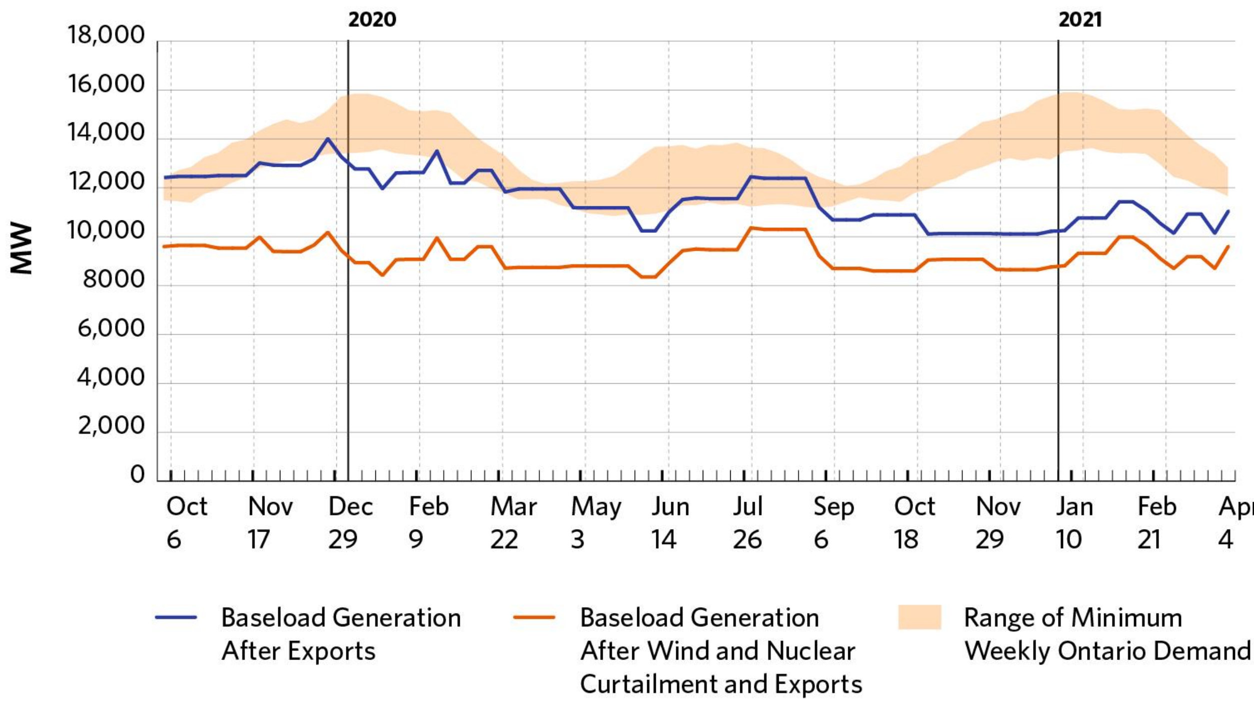

Figure 6-2 | Minimum Ontario Demand and Baseload Generation

The baseload generation assumptions include expected exports and run-of-river hydroelectric production, the latest planned outage information, and in-service dates for new or refurbished generation. The expected contribution from self-scheduling and intermittent generation reflects the latest data. Information on the dispatch order of wind, solar and flexible nuclear resources can be found in Market Manual 4 Part 4.2. Output from commissioning units is explicitly excluded from this analysis due to uncertainty and the highly variable nature of commissioning schedules. Figure 6-3 shows the monthly off-peak wind capacity contribution values calculated from actual wind output up to March 31, 2019. These values are updated annually to coincide with the release of the summer Outlook.

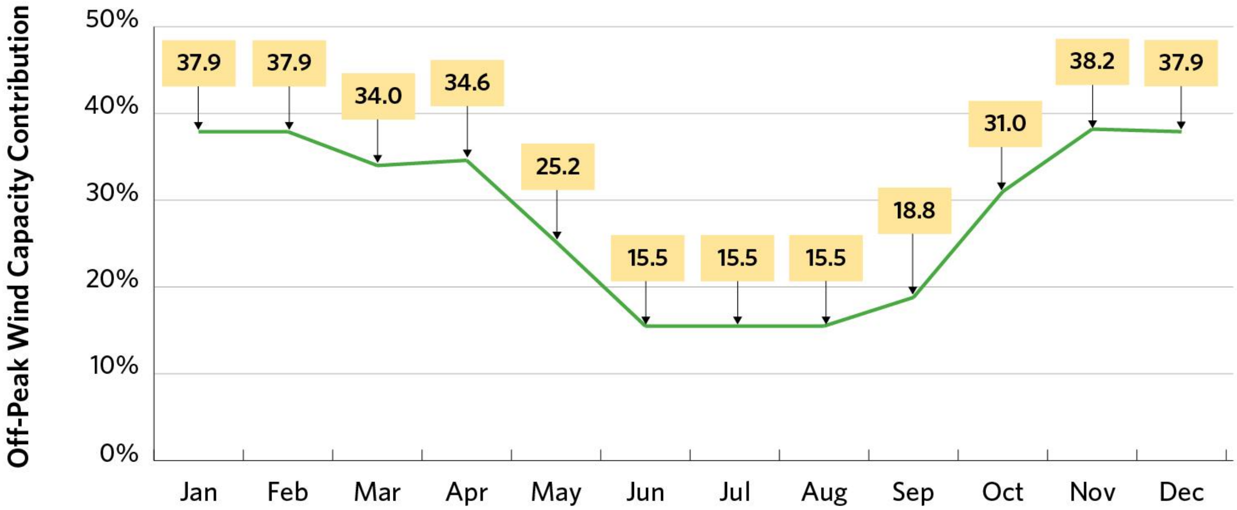

Figure 6-3 | Monthly Off-Peak Wind Capacity Contribution Values

7. Resources Referenced in Report

The table below lists resources in the order they appear in the report.

Table 7-1 | Additional Resources

Resource	URL	Location in This Report
Reliability Outlook Webpage	http://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Reliability-Outlook	Introduction
Security and Adequacy Assessments	http://www.ieso.ca/power-data/data-directory	Introduction
2019 Q3 Outlook Tables	http://www.ieso.ca/-/media/files/ieso/document-library/planning-forecasts/reliability-outlook/ReliabilityOutlookTables_2019Sep.xls	Throughout
Connection Assessments and Approval Process	http://www.ieso.ca/en/sector-participants/connection-assessments/application-status	Assessment Assumptions
Methodology to Perform the Reliability Outlook	http://www.ieso.ca/-/media/files/ieso/document-library/planning-forecasts/reliability-outlook/ReliabilityOutlookMethodology2019Sep.pdf	Throughout
Capacity Auction	http://www.ieso.ca/Sector-Participants/Engagement-Initiatives/Engagements/Capacity-Auction	Demand Measures
Enabling Capacity Exports	http://www.ieso.ca/en/Sector-Participants/Market-Renewal/Capacity-Exports	Firm Transactions
Ontario Resource and Transmission Assessment Criteria	http://www.ieso.ca/-/media/files/ieso/Document%20Library/Market-Rules-and-Manuals-Library/market-manuals/market-administration/IMO-REQ-0041-TransmissionAssessmentCriteria.pdf	Transmission Considerations
NERC Transmission Planning Standard TPL-001-4	http://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-4.pdf	Transmission Considerations
NPCC Directory #1	https://www.npcc.org/Standards/Directories/Directory_1_TFCP_rev_20151001_GJD.pdf	Transmission Considerations
Market Manual 4 Part 4.2	http://www.ieso.ca/-/media/Files/IESO/Document-Library/Market-Rules-and-Manuals-Library/market-manuals/market-operations/mo-dispatchdatartm.pdf?la=en	Surplus Baseload Generation
Grid-LDC Interoperability Standing Committee	http://www.ieso.ca/Sector-Participants/Engagement-Initiatives/Standing-Committees/Grid-LDC-Interoperability-Standing-Committee	Distributed Energy Resources

8. List of Acronyms

CAA	Connection Assessment and Approval
CROW	Control Room Operations Window
DER	Distributed Energy Resource
DR	Demand Response
EAA	Energy Adequacy Assessment
ESAG	Energy Storage Advisory Group
FETT	Flow East Toward Toronto
GS	Generating Station
GTA	Greater Toronto Area
ICI	Industrial Conservation Initiative
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
MW	Megawatts
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NYISO	New York Independent System Operator
ORTAC	Ontario Resource and Transmission Criteria
PAR	Phase Angle Regulator
RAR	Reserve Above Requirement
RAS	Remedial Action Scheme
SBG	Surplus Baseload Generation
SCC	Solar Capacity Contribution
TS	Transmission Station
TWh	Terawatt-hours
WCC	Wind Capacity Contribution

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Connecting Today.
Powering Tomorrow.

UNDERTAKING J3.4

IESO UNDERTAKING J3.4

UNDERTAKING

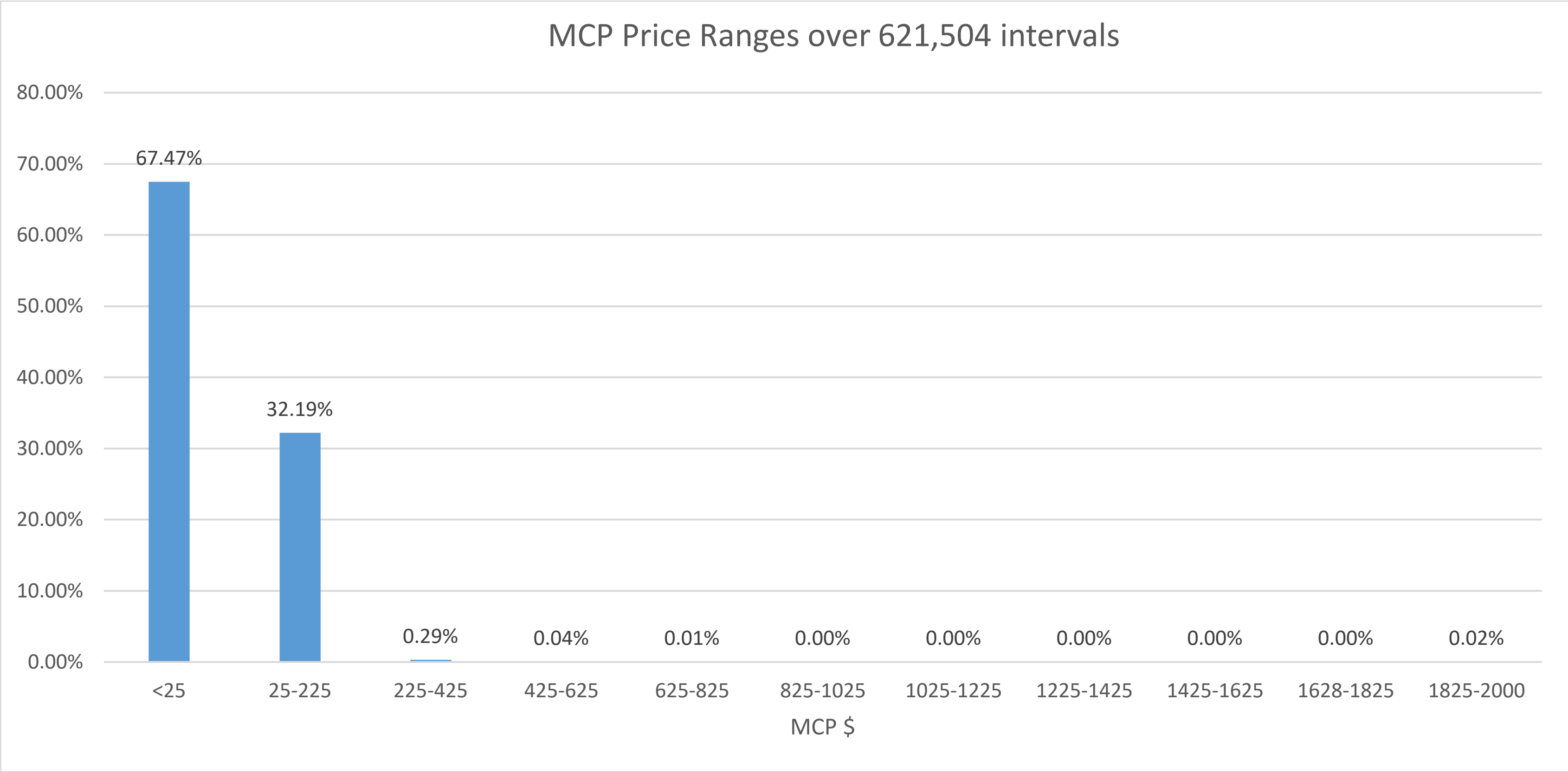
To produce a distribution graph of five-minute-interval real-time energy prices in $200 increments, between $25 and the maximum over the last five years

RESPONSE

The distribution graph for the over 621,000 5-minute intervals over the last five years is attached.

UNDERTAKING NO. J3.4:

TO PRODUCE A DISTRIBUTION GRAPH OF FIVE-MINUTE-INTERVAL REAL-TIME ENERGY PRICES IN $200 INCREMENTS, BETWEEN $25 AND THE MAXIMUM OVER THE LAST FIVE YEARS.



UNDERTAKING J3.7

IESO UNDERTAKING J3.7

UNDERTAKING

With reference to the list of demand response participants at tab 1 of the Post-Auction Summary Report, to indicate the virtual DR participants and total megawatt capacity for the group and whether it differs from the Post-Auction Report.

RESPONSE

A table with the requested information is attached. These numbers do not differ from the Post Auction Report that was posted on the 3rd of May 2019.

DR Auction Results - Participant Details

ZONE	Demand Response Auction Participant	Summer Commitment Period (May 01, 2018 - Oct 31, 2018)	Winter Commitment Period (Nov 01, 2018 - Apr 30, 2019)
		Cleared DR (MW)	Cleared DR (MW)
EAST	ENEL X CANADA LTD.	26.7	29.2
	NRG CURTAILMENT SOLUTIONS CANADA, INC.	5.4	4.6
	RODAN ENERGY SOLUTIONS INC	25.4	37.4
ESSA	ENEL X CANADA LTD.	5.7	9
	GC PROJECT LP	2.5	2.2
	NRG CURTAILMENT SOLUTIONS CANADA, INC.	2.2	2.1
	RODAN ENERGY SOLUTIONS INC	2.8	8.1
NIAGARA	ENEL X CANADA LTD.	16.7	14.2
	NRG CURTAILMENT SOLUTIONS CANADA, INC.	1	1
	RODAN ENERGY SOLUTIONS INC	2.5	5
NORTHEAST	ENEL X CANADA LTD.	1.7	-
	RODAN ENERGY SOLUTIONS INC	24.5	26.2
NORTHWEST	NRG CURTAILMENT SOLUTIONS CANADA, INC.	1	0
OTTAWA	ENEL X CANADA LTD.	5.4	4.9
	GC PROJECT LP	1.1	1
	NRG CURTAILMENT SOLUTIONS CANADA, INC.	1.8	1
	RODAN ENERGY SOLUTIONS INC	15	17.1
SOUTHWEST	ENEL X CANADA LTD.	35	31.8
	GC PROJECT LP	3.4	3
	NRG CURTAILMENT SOLUTIONS CANADA, INC.	14.3	46.5
	NRSTOR C&I L.P.	-	4.5
	RODAN ENERGY SOLUTIONS INC	21.4	36
TORONTO	ALECTRA UTILITIES CORPORATION	1	-
	ENEL X CANADA LTD.	41.7	34.4
	GC PROJECT LP	6	5
	NRG CURTAILMENT SOLUTIONS CANADA, INC.	27	34
	NRSTOR C&I L.P.	-	2.5
	OHMCONNECT, INC	2	0
	RODAN ENERGY SOLUTIONS INC	64	71
	TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	10	-
WEST	ENEL X CANADA LTD.	17.1	20.2
	GC PROJECT LP	2.5	2.3
	NRG CURTAILMENT SOLUTIONS CANADA, INC.	7.4	2.5
	NRSTOR C&I L.P.	-	1.2
	RODAN ENERGY SOLUTIONS INC	12.8	14.1

Total MWs	**407**	**472**
Total contributing Virtual resources	**32**	**30**
List of organizations	ENEL X CANADA LTD.	ENEL X CANADA LTD.
	NRG CURTAILMENT SOLUTIONS CANADA, INC.	NRG CURTAILMENT SOLUTIONS CANADA, INC.
	RODAN ENERGY SOLUTIONS INC	RODAN ENERGY SOLUTIONS INC
	GC PROJECT LP	GC PROJECT LP
	ALECTRA UTILITIES CORPORATION	NRSTOR C&I L.P.
	OHMCONNECT, INC	
	TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	

ENEL X CANADA LTD.
NRG CURTAILMENT SOLUTIONS CANADA, INC.
RODAN ENERGY SOLUTIONS INC
GC PROJECT LP
NRSTOR C&I L.P.
ALECTRA UTILITIES CORPORATION
OHMCONNECT, INC
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED