April 20, 2020

IESO Stakeholder Engagement (Delivered via email)

Re: Market Rules:

- **Appendix 4.2 – Requirements for Generation Facilities Connected to the IESO-Controlled Grid**
- **Appendix 4.3 – Requirements of Connected Wholesale Customers and Distributors Connected to the IESO-Controlled Grid**

OPG's comments are:

<u>Appendix 4.2 – Requirements for Generation Facilities Connected to the IESO-Controlled Grid</u>

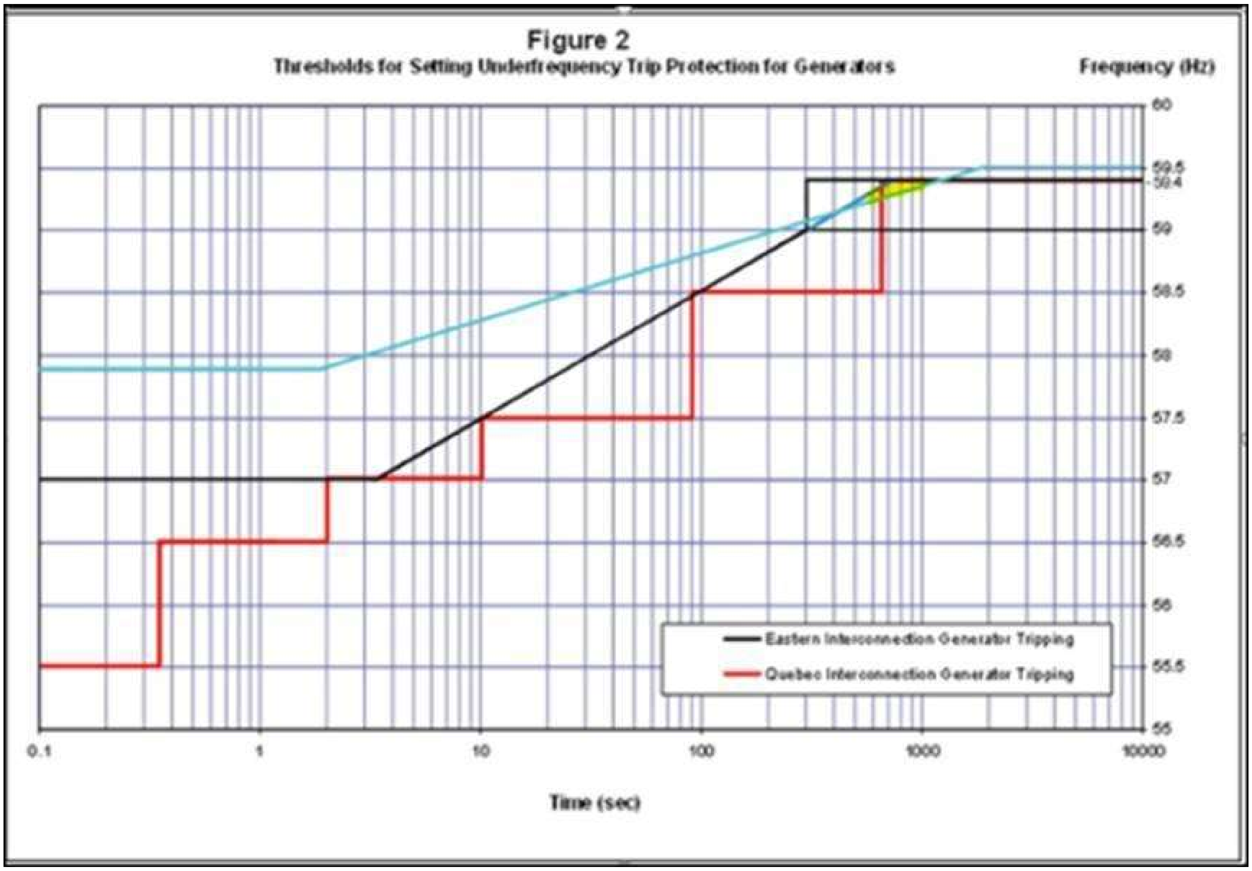
1) Category #1 Off – Nominal Frequency Operation

OPG is of the opinion that additional clarifications with respect to the intent of the amendment for Off-Nominal Frequency Operation are required, per the observations below.

There is a gap in the area for continuous operation and there can be cases where market participants will follow the IESO Market Rule yet will not be in compliance with the NERC Reliability Standard requirements pertaining to frequency protective relay settings.

The area highlighted in yellow on the graph below illustrates where the IESO requirements are less stringent than NERC requirements. By tripping the generating units in this area, Market Participants are compliant with the IESO Market Rules and non-compliant with the NERC requirements.

OPG would like clarification on why the IESO is introducing Market Rule requirements that are less stringent than the NERC Reliability Standard requirements pertaining to frequency protective relay settings.



Notes:

- Functional equation for the curve in NPCC Directory #12

Time	Frequency
t ≤ 3.3 sec	f = 57 Hz
3.3 Sec ≤ t ≤ 300 sec	f = 1.021 x log (t) + 56.471 Hz
t ≥ 300 Sec	f = 59 Hz

- IESO Market Rule - Chapter 4 - Grid Connection Requirements – Appendix 4.2 – Generation Facility Requirements

1. Off-Nominal Frequency Operation	Operate continuously between 59.4 Hz and 60.6 Hz and for a limited period of time in the region above bounded by the straight lines on a log-linear scale defined by the points (0.0 s, 57.0 Hz), (3.3 s, 57.0 Hz), and (300 s, 59.0 Hz) and the straight lines on a log-linear scale defined by the points (0.0 s, 61.8 Hz), (8 s, 61.8 Hz), and (600 s, 60.6 Hz).

- NERC Standard PRC-024-2 — Generator Frequency and Voltage Protective Relay Settings

Eastern Interconnection

High Frequency Duration		Low Frequency Duration	
Frequency (Hz)	Time (Sec)	Frequency (Hz)	Time (sec)
≥61.8	Instantaneous trip	≤57.8	Instantaneous trip
≥60.5	$10^{(90.935-1.45713*f)}$	≤59.5	$10^{(1.7373*f-100.116)}$
<60.5	Continuous operation	> 59.5	Continuous operation

Additionally the Market Manual 2: Market Administration Part 2.20: Performance Validation, 3.1 Off-Nominal Frequency Operation should be revised to reflect the "do not trip region" that cannot be defined by colored graphs without properly defining the mathematical functions for the boundaries of the domain region.

2) Category #3 Voltage Ride Through

The terms "momentary current cessation" and "momentary cessation" are not defined, nor commonly understood.

Significant reduction of the amount of current being injected has a similar effect to momentary current cessation; they both deprive the grid of much needed support during the disturbance which negatively impacts grid reliability. Understanding the compounded effect on the grid of a multitude of inverters having similar design is important and accurate modelling may not be possible without adequate information regarding the current-limiting behavior of inverter-based resources.

OPG recommends instead of the proposed change "Momentary current cessation is not permitted without IESO approval." to use the following proposed language: "For inverter-based systems, momentary current cessation or reduction of output during system disturbances is not permitted without IESO approval."

3) Category #4 Active Power

OPG understands and appreciates the IESO’s explanation given in response to OPG’s previous comments on Category 4 (IESO feedback posted on the ESAG webpage on August 6, 2019). OPG agrees with the IESO’s intention to ensure an adequate supply of reactive power, and wishes to have the Market Rules clearly elaborate the reactive power requirements in relation to the operating voltage range. OPG notes, however, that it may not be necessary to address this concern in Category 4 and so suggests suitable improvements elsewhere.

A much deeper discussion associated with OPG's previous comment (submitted September 9, 2019) about the +/-5% voltage range is now included with Category 5. It may be meaningful for the IESO to revisit the associated phrasing in Category 4 in conjunction with the recommendations OPG is making for Category 5.

OPG recommends defining here in Category 4, in addition to the term 'Rated Active Power', the terms 'Maximum Continuous Active Power', and 'Maximum Active Power Capability', which are used in IESO Online, and have some correlation to the terms 'Maximum Generation Resource Active Power Capability (MGC)' and 'Pmax' which are used in the IESO's MOD-025 test form (form 56). It would help bring clarity to all if these terms were defined and used consistently across the IESO's documents and procedures. Where particular terms are attached to requirements, it would be useful to clearly elaborate those requirements here in Appendix 4.2.

Another suggestion for the IESO's consideration is to incorporate the idea that multiple generators (or resources) could be connected to the low voltage terminal of a main output transformer. Each of them may have its own 'rated active power' value, and there needs to be a concept of the 'aggregated' or sum total amount of 'rated active power' that is attached to the MOT. In the proposed new language in Category 5, the reactive obligation at the high-voltage side of the MOT is based on RAP – which OPG assumes is intended to be the aggregated sum of all the connected resources’ 'RAP' values for a system that has one MOT and many generators/resources (where there is not a single generator with its own RAP value). The phrasing could be clarified to acknowledge this, and better align with the shift away from requirements specified at the terminals of individual generators (on the low-voltage side of the MOT) to a joint requirement being specified at the high-voltage side of the MOT.

4) Category #5 Reactive Power

See associated **Background and Discussion** section at the end of the document for a more thorough discussion of the changes recommended by OPG, and their basis.

Here are OPGs recommended changes to the language in Category 5:
Have the capability to inject or withdraw continuously (i.e., dynamically) at the high voltage terminal of the main output transformer reactive power up to 33% of its rated active power, when operating at all levels of active power output and at the nominal terminal voltage of the equipment connected to the low voltage side of the main output transformer, except where a lesser continually available capability is permitted by the IESO. It will not be expected to operate equipment connected to the low-voltage side of the main output transformer outside a +/- 5% range of its rated terminal voltage to satisfy these reactive power requirements.

As in Category 4, the phrasing here could be made to better acknowledge the likelihood of having multiple generators (resources) connected on the low-voltage side of the MOT, and that 'rated active power' probably means the sum of all the individual generators' RAP values taken in aggregate (unless this is made obvious by revised phrasing in Section 4).

Regarding the new proposed wording related to Reactive Compensation:
OPG believes that this term 'reactive compensation' should be defined, as the generic use of these words (rather than a defined term) may mean a variety of things, e.g., load current compensation within the AVR controls such as line-drop compensation; static capacitor banks; FACTS controllers, etc. What is intended here?

If the intent is load current compensation within the AVR, the default state here (**reactive compensation shall be provided**) may be considered contradictory to the default state in Section 6 (regulate voltage at the generator terminals & **AVR reference compensation shall not be enabled**), though OPG acknowledges that both clauses make reference to requiring IESO approval, which presumably would be the mechanism for establishing what the requirement would ultimately be and for resolving any apparent contradiction.

This provides the IESO with the required control, but does not provide Market Participants with the much needed direction/indication about what criteria the IESO will use to determine acceptability.

Many systems will require case-by-case decisions by IESO. OPG recommends IESO provide more explicit/transparent expectations to facilitate independent decision making by Market Participants.

5) Category #6 Automatic Voltage Regulator (AVR)

See associated **Background and Discussion** section at the end of the document for a more thorough discussion of the changes recommended by OPG, and their basis.

Regarding removal of language pertaining to AVR setpoint compensation:
For stations that have multiple generating units sharing a Main Output Transformer (MOT), it is absolutely necessary to have some kind of AVR setpoint compensation, usually 'reactive droop compensation', to achieve acceptable voltage control of the shared terminals.

OPG acknowledges that the IESO is typically reasonable with granting permission for use of load current compensation (usually reactive droop compensation within AVRs on generators with shared terminals), but OPG's previous comment (submitted September 12, 2019) on this section was intended to provide Market Participants with certainty that IESO ***would*** approve the configuration, and that only the **settings** would be subject to approval. OPG believes that this comment is still relevant, and that it would be valuable to Market Participants to have the IESO be more transparent about what criteria it would use to grant permission, if it is not made explicit that the IESO will grant approval for configurations in which it is certain that such functions will be needed. The way this requirement is presently written could be interpreted as enabling the IESO to disallow configurations where multiple generators share a common terminal bus - is this the IESO's intent?

OPG still believes that IESO should adopt standard IEEE 421.1 terminology (i.e., Load Current Compensation, including: reactive droop compensation, reactive differential compensation, and line drop compensation).

OPG proposes that the IEEE term that would be equivalent to the phrase used is 'load current compensator', and is defined as follows**:** A function that acts to influence the voltage regulator action to control voltage at a point other than where the synchronous machine voltage is measured. Specific uses are reactive droop compensation, reactive differential compensation, and line drop compensation.

The three types of compensation mentioned in the above definition are defined as follows:

- **reactive droop compensator**: A function that causes a reduction of terminal voltage proportional to reactive current. Generally used to obtain reactive current sharing among synchronous machines operating in parallel.
- **reactive differential compensator**: A function used to obtain reactive current sharing among synchronous machines operating in parallel without causing reduction of terminal voltage. Requires interconnection of voltage regulators or current transformers of the machines.
- **line drop compensator**: A function that modifies the machine terminal voltage to compensate for the impedance drop to a fixed point external to the synchronous machine terminals.

OPG proposes that the following language be used in this category:
AVR load current compensator functions shall not be enabled without IESO permission. IESO shall allow use of load current compensator functions where necessary to achieve acceptable voltage control of a shared terminal bus, with configuration subject to IESO approval.

OPG believes it is inappropriate to specify a requirement for main output transformer impedance in this section (and perhaps it is not appropriate at all).

The reactive power obligation now specified in Section 5 to apply at the HV side of the transformer already implies that it will be necessary to have an acceptable combination of transformer impedance and reactive power capability/operating voltage range at the generator terminals (such as the presently specified combination of power factor range from 0.9 lagging to 0.95 leading at RAP, with a transformer impedance not exceeding 13% - though this is not the only combination that would achieve the reactive requirement at the HV terminal of the MOT). OPG has commented in detail in Section 5 about the reactive power obligations and voltage range, and this consideration (transformer impedance) should be harmonized with whatever decisions are taken there, since these three considerations are all related, and only two of the three can be directly specified before the other becomes fully determined (e.g., if voltage range and reactive power range at the LV side of the main output transformer are specified, along with the reactive obligation at the HV side of the MOT, then the maximum transformer impedance is determined).

Further, if the IESO insists that it is necessary to limit the transformer impedance, it should be done in a stand-alone section that pertains to Main Output Transformers, rather than in the AVR section. If such a specification is made, it should be accompanied by a compatible requirement specifying the suitable range of reactive power/operating voltage at the generator terminals (or more generically at the LV terminals of the main output transformer) to achieve the reactive power requirements specified at the HV side of the MOT.

Additionally, if impedance must be restricted to some maximum value (and stated in per unit or in percent on some basis), it will be necessary to have stated in the Market Rules a meaningful **basis** on which the *per unit* impedance is to be specified.

MVA Base:
OPG would contend that the base MVA value should NOT be the aggregated *apparent power* (MVA) values of the generators connected to the MOT, since the generators' MVA values may not have a sensible relationship to the *active power* that the generator and its turbine are intended to produce. Specifically, the MVA values may be MUCH LARGER than would be needed for the achievable active power output, with a reasonable amount of reactive power support, such as 0.9 lagging PF. For example, if the achievable active power were only 50 MW, an apparent power rating of 56 MVA would allow 0.9 lagging power factor operation at this active power, and would be a suitable basis

for specifying the MOT impedance. If the rated apparent power of the generator were much larger than this, say 100 MVA, then the way this requirement is written would demand an abnormally small per unit impedance (if the transformer were sensibly sized at approximately 56 MVA) or a similarly over-sized transformer with an impedance in the normal range for power transformers (around 0.10 p.u.). This will have cost implications, and other negative side effects (available fault currents through the transformer will be larger than necessary if the transformer impedance is made abnormally small).

As a more appropriate alternative, OPG would propose that the MVA basis on which the transformer impedance might be specified (again, if the IESO deems it necessary at all) could be the MVA value that corresponds to 'the aggregated Rated Active Power values' or even the aggregated 'Maximum Active Power Capabilities' of all the generators connected to the transformer, with the group operating jointly at 0.9 lagging power factor, i.e.:

MVA_base = (aggregated MW)/0.9 = 111% (aggregated MW).

It would also be easy to state a proportionally smaller base impedance on an MVA base that is equal to the aggregated MW value (e.g., rather than, say, 13% on the MVA base that is equal to 1/0.9 times the aggregated MW value, it could be stated equivalently as 0.9*13% = 11.7% on the aggregated MW base.

Voltage Base

The **voltage** basis for the impedance should also be specified. It is common practice to have main output transformer LV windings rated differently (lower) than the nominal terminal voltage of the generator to which it is connected. The reason for this difference is to compensate for the 'regulation' of the transformer when loaded. Given that there may be two different pieces of equipment attached to the same bus - each with its own, different 'nominal' voltage rating - either the MOT’s LV winding's nominal voltage or the generator's nominal terminal voltage would be sensible choices for calculating the base impedance of the main output transformer (and most people would probably choose the transformer's own equipment base). The lack of a specified basis would result in a choice having to be made, and this would also make it difficult to determine compliance with this rule.

6) Category #7 Excitation System

While OPG appreciates to see its previous comment addressed, it is now recognized that there may still be some ambiguity in the phrasing in this draft (i.e., that the generator is on open circuit but its field is to be supplied by the exciter, rather than the exciter itself being on open circuit), and proposes that the intended operating conditions be further clarified as follows:
Provide (a) Positive and negative ceilings not less than 200% and 140% of rated field voltage, respectively, while supplying the field winding of the generator operating at nominal voltage under open circuit conditions.

This would imply that the excitation transformer secondary voltage must be adequate to provide 200% of the rated field voltage while overcoming the voltage drops that would result when the generator's 'open-circuit field current' is flowing in the excitation transformer, bridge, cables, generator slip-ring brushes, etc., and that idealized calculations that convert the AC secondary voltage of the excitation transformer to a theoretical DC equivalent value without accounting for voltage drops, actual minimum bridge firing angle, etc., would not be adequate. Is this what the IESO intends?

Regarding the new proposed language that defines rated field current:
"Rated field current is defined at rated voltage, rated active power, and the maximum continuous reactive power required under Category 5 of this Appendix."

The proposed changes in Section 5 no longer has a specific reactive power obligation stated at the terminals of the generator; there are implications to this, and it is not obvious that the possible change of the requirement was intended by the IESO. The main scenario where this change in language would create a different requirement is where a main output transformer's low voltage bus is shared by several generators.

The following reasoning applies:

- The 'rated field current' of a generator is now tied to an amount of reactive power that must be delivered on the HV side of its possibly-shared MOT (where previously, the obligation would usually have been defined by the machine's own RAP and 0.9 PF at the machine terminals).
- The machine's 'rated field voltage' is dependent on the 'rated field current' and field winding resistance at nominal temperature, and
- The machine's required ceiling voltage is dependent on the 'rated field voltage'.
- The required secondary voltage (low-side voltage) for a given machine's excitation transformer is therefore tied to the reactive power obligation at the HV side of the MOT, and this obligation may be ***shared with other generators***.

For a group of generators that share a bus, the 'rated field current' is no longer well-defined based on the machine's own ratings (namely, its own RAP and 0.9 PF), but rather must be determined jointly with all the other units that share its terminal bus. This would probably be done through some apportioning of the joint requirement to each generator within the group. There are several sensible ways this may be done.

E.g.,

- Each generator gets apportioned an ***equal share*** of the joint reactive power obligation; OR
- Each generator gets a ***proportional share*** of the obligation, perhaps based on its MVA rating as a fraction of the total MVA connected to the MOT, or based on its RAP as a proportion of the total aggregated RAP values connected to the MOT; OR
- Each generator gets a ***share of the joint obligation defined by its ability to deliver it*** (in which case, not all units would have the same obligation to operate with a particular power factor range at its terminals, and ceiling voltages would have to be defined by the amount of reactive power apportioned to that particular machine).
- Etc.

Depending on how apportioning was done, it would no longer be simple to determine the steady state reactive power requirements for a machine based on its own characteristics and ratings, but would have to be specified within its group and tracked. Forcing capabilities would also no longer be simple to determine based on the machine's own characteristics.

Unintuitive situations may result if some sub-set of the connected generators are operating and the other was shut down - e.g., say three generators are connected to a shared main output transformer LV bus, and the reactive power obligation was apportioned to them as: 60% / 20% / 20%, while they all had the same active power capability. When the unit with 60% of the reactive power capability was not in service, the remaining ones would have a disproportionately low reactive capability relative to the active power output (with lower ceiling voltage capabilities, as determined by the apportioning of the reactive power). Would this be acceptable to the IESO?

7) Category #9 Phase Unbalance
IESO should clarify what is 2% requirement at the high voltage terminal of MOT? Is it for Phase Unbalance Current? If so, the proposed language is:
"Provide an open circuit phase voltage unbalance not more than 1% and operate continuously with a phase unbalance <u>current</u> as high as 2% at the high voltage terminal of its main output transformer".

8) Category #10 Armature and Field Limiters
For synchronous machines, and salient-pole hydro generators in particular, the continuous capability may commonly be limited by the saliency circle in the under excited region, in addition to field current and armature current (while core-end heating mainly affects turbo-generators). OPG suggests adding the saliency circle to the list of recognized limits that will affect the continuous operating range:
"Provide short-time capabilities specified in IEEE/ANSI 50.13 and continuous capability determined by either field current, armature current, ~~or~~ core-end heating, or the saliency circle. More restrictive limiting functions, such as steady state stability limiters, shall not be enabled without the IESO approval."

Background and Discussion:

OPG appreciates the intention the IESO has described in response to OPG's previous comments (submitted September 12, 2019) on Category 4, and understands the importance of adequate reactive power support and agrees with including strong requirements to ensure Market Participants will provide it.

However, OPG observes that there has been a trend in the Market Rules revisions (from before 2010 to now), in which the requirements that oblige conventional synchronous generators to provide reactive support have become less explicit and less direct. Because of these well-intended changes, some of the clarity in the requirements has been lost. Obviously, this has been driven by the need to accommodate new technologies and make the rules more generic and applicable to all types of Generation Facilities. As the requirements have continued to evolve, OPG has noticed that some of the long-standing practices and expectations that have been taken for granted are not represented clearly in the newest version of these requirements, and that it would be advantageous to all Market Participants if these practices were renewed and clarified in this update to the Appendix.

OPG understands that the following concepts are intended by the IESO, but observes that it would not be possible to come to the following understanding based only on the wording contained in the current draft of the requirements in Appendix 4.2:

In order to be allowed to offer active power into the Market, a generator must be able to deliver a minimum amount of reactive power at all achievable active power outputs.

The minimum range of lagging MVAr the generator needed to produce used to be (before 2010) defined *at its terminals*, and was explicitly stated to be the based on *nominal generator terminal voltage*. The reactive power obligation corresponded to the range of reactive power present when the generator was operating at Rated Active Power (RAP) and with a power factor between 0.9 lagging and 0.95 leading:

> "A synchronous generation unit shall have the capability to supply, at its terminal, reactive power within the range 90% lagging (overexcited) to 95% leading (underexcited) power factor, based on rated active power at rated voltage."

Additionally, Appendix 4.2 previously stated that generators must be able to operate continuously "at full output" within ±5% of its rated terminal voltage, but was explicit that generators would not be expected to operate outside a range of ±5% terminal voltage range in order to satisfy reactive power requirements:

> Each *generation facility* shall be capable of operating continuously at full output within ± 5% of the *generation facility's* rated terminal voltage. All plant auxiliaries shall be capable of running continuously within this range.
> Each *generation facility* shall not be expected to operate continuously outside this voltage range to satisfy reactive power requirements.

In 2010, the location at which the reactive power obligation was defined moved from the generator terminals to the 'connection point'. The main requirement became that the generator must be able to inject or withdraw at the connection point an amount of reactive power that was equal to 33% of the RAP, but an equivalence between the previous requirement and the new requirement was identified.

This update to the Market Rules stated that a generator that met the pre-existing requirement at the generator terminals would also be acceptable according to the new requirement, if the Main Output Transformer impedance did not exceed 13% based on the generator apparent power. (It is notable that the notion of the MOT impedance being limited to 13% was introduced to elaborate the equivalency between old and new reactive power requirements).

It is OPG's opinion that a number of these changes, taken together, have made the relationship between reactive power obligations and terminal voltage for conventional generators less clear. The particular changes that have created uncertainty include the following:

- The clear statement that the reactive power obligation was specified *at the generator's nominal terminal voltage* was removed in 2010
- The statement that generators would not be required to operate outside their terminal voltage range of ±5% to deliver their reactive power obligation was also removed in 2010.
- The statement that the generator must operate continuously *at full output* within ±5% terminal voltage became the requirement that presently exists in Section 4 to "Supply continuously all levels of ***active power*** [OPG emphasis] output for 5% deviations in terminal voltage", removing the association between *reactive power* and the *voltage range*. The phrase 'full output' could have reasonably been interpreted as 'rated MVA and rated power factor' (consistent with requirements placed on generator design by the two common industry standards for generators – C50.12 & C50.13) and included reactive power capability. The current phrasing does not allow this interpretation.

Though these changes were made back in 2010, OPG observes that through the last 10 years both OPG and the IESO have been tacitly operating as though these requirements have remained in place (since no alternative requirements replaced them, and the prior requirements were sensible).

Examples supporting this observation:

- Reactive Capability Curves are still the primary tool used to describe reactive power capability of conventional generators (at the generator terminals), and the curves are shown at nominal terminal voltage.
- MOD-025 reactive capability testing is still carried out with the measure of a successful test being that the reactive power obligation – defined by the power factor range of 0.9 lagging to 0.95 leading at RAP, *at the generator terminals* – has been achieved.
- A valid stopping criterion for such testing (MOD-025) has continued to be that the generator has reached a 5% deviation from its nominal terminal voltage.
- It is still expected that limiters, such as over-excitation limiters, be set so that the reactive power obligations can be met at *nominal* voltage for all achievable levels of active power output.

To close these gaps and provide improved certainty and clarity for Market Participants, OPG recommends the following changes (OPG recommendations in red text; IESO existing text/proposed change in underlined or ~~strikethrough red text~~):

> Have the capability to inject ~~Inject~~ or withdraw ~~reactive power~~ continuously (i.e., dynamically) at the high voltage terminal of the main output transformer ~~a connection point~~ reactive power up to 33% of its rated active power, when operating at all levels of active power output and at the nominal terminal voltage of the equipment connected to the low voltage side of the main output transformer, except where a lesser continually available capability is permitted by the IESO. It will not be expected to operate equipment connected to the low-voltage side of the main output transformer outside a +/- 5% range of its rated terminal voltage to satisfy these reactive power requirements.

Even with these proposed changes, OPG would point out that the obligation is not fully determined. To completely specify the reactive power obligation, it will be necessary to specify at least one more variable – either the transmission system voltage at which the obligation applies, or the main output transformer impedance (or a maximum value, as is done now).

These comments have bearing on Categories 4, 5, 6 and 7 of the Proposed Market Rules Appendix 4.2

Appendix 4.3 – Requirements of Connected Wholesale Customers and Distributors Connected to the IESO-Controlled Grid

OPG appreciates the opportunity to provide comments. OPG is content with the previously provided comments disposition by the IESO, and has no further comments regarding the proposed modifications to Appendix 4.3.

For additional discussion please do not hesitate to contact Mr. Mike Cooke.

Regards,

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