Single Schedule Market – Phase 2, Session 2
August 17, 2017

Minutes of Meeting

Date held: August 17, 2017	**Time held:** 9 am – 3 pm	**Location held:** Crowne Plaza Toronto Airport
Company	**Name**	**Attendance Status** (A)ttended; Attended via Webex
Amp Solar Group Inc.	Luukkonen, Paul	WebEx
AMPCO	Anderson, Colin	A
AMPCO	Dottori, Paul	A
AMPCO (behalf of)	Wright-Hilbig, Rhonda	A
APPrO	Butters, David	A
Bruce Power	Whitehead, Paul	A
Bruce Power	Dalzell, Pat	A
CanWEA	Giannetta, Brandy	WebEx
Capital Power Corporation	Yuan, Yining	WebEx
Centre Lane Trading Ltd.	Deaves, Michael	A
Centre Lane Trading Ltd.	Nikkel, Jonathan	A
Customized Energy Solutions	Tinkler, Mark	A
Enbridge	Chin, Edith	WebEx
Enbridge	Jayaraman, Jay	A
EnerNOC, Inc.	Griffiths, Sarah	WebEx
FTI Consulting	Harvey, Scott	A
FTI Consulting	Pope, Susan	A
Gerdau	Forsyth, Dave	WebEx
H2O Power	Somerville, Stephen	A
Hydro Quebec	Belanger, Frederic	WebEx
Ministry of Energy	Weir, Ben	WebEx
Nalcor Energy	Martin, Davie	WebEx
Northland Power Inc.	Samant, Sushil	A
Northland Power Inc.	Khan, Shahid	WebEx
Ontario Power Generation	Wizniak, Lynn	A
Ontario Waterpower Association	Norris, Paul	WebEx
Power Advisory LLC	Cumming, Alison	A
Powerful Solutions	Inman, Peter	A
RBC Capital Markets	Doolittle, Robin	WebEx
Resolute Forest Products	Degelman, Cara	A
Rodan Energy Solutions	Goddard, Rich	WebEx
Tembec	Dottori, Paul	A
TransAlta	Nguyen, Thanh	A
TransCanada Energy	Kuntz, Margaret	A

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Company	**Name**	**Attendance Status** (A)ttended; Attended via Webex
Whisker Labs	King, Robert	A
Workbench Corp.	Sears, Heather	WebEx
IESO	Agavriloai, Ioan	A
IESO	Ellard, Barbara	A
IESO	Kandola, Shan	A
IESO	King, Ryan	A
IESO	Louw, Brennan	A
IESO	Matsugu, Darren	A
IESO	Sapona,Ingrid	A
IESO	Scratch, Jonathan	A

Scribe: Ingrid Sapona. Please email any corrections, additions or deletions e-mail to the scribe (ingrid.sapona@ieso.ca).

Meeting Started at 9 a.m.

Introduction – Ryan King, IESO

The IESO welcomed participants to Phase 2, Session 2: design element options and preliminary decisions.

The IESO noted it has created three tools to assist stakeholders and to bring greater transparency on how actions/issues are being addressed: SSM Actions Log; SSM Issues Lot; SSM Design Element Tracker, all of which can be found at: http://www.ieso.ca/en/sector-participants/market-renewal/market-renewal-single-schedule-market

Agenda – Jonathan Scratch, IESO

The IESO updated stakeholders on the SSM workplan and provided a summary (Slide 8) of who will likely be affected by today's main topic: Load Pricing. The IESO also reiterated that the purpose of today's session is to continue to present options, not make decisions about design elements.

Introduction to Load Pricing Options (Slides 4 - 41) – Susan Pope, FTI

FTI presented seven options for pricing loads, focusing on three choices:

- Choice 1 – charging the marginal or average cost of losses and congestion;
- Choice 2 – using the same or different pricing methodologies for dispatchable and non-dispatchable load; and,
- Choice 3 – the level of price granularity (nodal, zonal or uniform).

A participant remarked that when other markets opened, they only had operating telemetry for metering to calculate nodal congestion on the supplier side. If ISOs have started using zonal prices, how have they done so?

FTI indicated that some markets were using prices at supplier nodes, but they were using them as proxies for load prices. Such markets had prices available in their telemetry system for suppliers located right next to the load, so the supplier prices provided a good approximation of the marginal losses and congestion for the load. FTI noted that doing that is different from saying we're going to use the supplier price if a percentage of the supply is coming from someplace that's very different from the load's location.

The participant commented that if the IESO "went marginal on the losses", the participant didn't think the IESO would ever have all the loads with telemetry, so some calculations would have to be based on estimation or some sort of proxy data.

FTI agreed, noting that it assumes there will be some way of approximating or measuring prices at load locations, whether through metering or proxying the price through a supplier location. FTI cautioned not to blur the distinction between calculation of prices at a location and metering of the load – they are separate ideas. Some of the issues being discussed relate to the fact that the software is built, in general, to calculate shift factors for generator locations and not for load locations.

A participant asked whether there is any software currently capable of calculating shift factors.

FTI said all software is capable of it but, at this point, it's unknown how difficult it may be to do.

A participant wondered if it is different for dispatchable loads, for example, if there is an energy storage facility or a pump facility whose main purpose is to provide system support and uniform pricing is used for dispatchable load, could there be a carve out for that kind of load?

FTI said those kinds of carve outs exist and the blended option will be explained later. The key will be how dispatchable load is defined.

A participant asked if such carve outs drive marginal cost of congestion and losses. If there are special cases, you must ensure that losses and congestion are calculated on marginal not average.

FTI agreed, noting that blended alternatives are used in systems where zonal pricing is also based on marginal cost of congestion and losses.

A participant asked if zonal and uniform pricing are the same if there's only one zone.

FTI said yes.

A participant asked whether a dispatchable load can provide operating reserve (OR) and get paid nodally for the OR?

FTI agreed to take this back. The alternative for that load is going to be a trade-off between providing an energy price zonally or uniformly vs. a nodal price for OR; it will be important to make sure the proper incentives are in place.

Load pricing - Option 1 (Slides 8-12) – Nodal for all loads with marginal congestion and loss.

FTI noted that this choice represents a big change from the current situation and there's a stark contrast between efficiency on one hand and the degree of change/impacts on the other hand.

A participant asked whether there are any jurisdictions allow load to opt in/opt out. The participant noted that until the modeling is done, it may be hard for a load to make a recommendation.

FTI said US jurisdictions allow opt/in and opt/out, but they basically have nodal pricing. Opting in means the nodal price is paid; opting out means the nodal price gets rolled into the price the residual zone pays. There would be metering costs and other things to be taken into account.

A participant wondered whether the settlement process is a potential problem if people are opting in and out and asked whether, in such cases, it is settled daily, weekly, monthly, or yearly?

Usually the opt-in/out is offered on an annual basis. FTI indicated that in some systems that are zonal and that have co-optimization for energy and reserves, there are options for loads that might want to be dispatchable. There is no difference in the time step for the settlement of the two. FTI cautioned, however, that steps must be taken so costs don't get shifted onto other loads. Also, those ISOs require participants to periodically elect to be priced nodally.

The IESO clarified that in the US jurisdictions described by FTI, "optionality" is where participants have the option to be priced nodally; otherwise, they would be settled based on a zonal price. No ISO's include option to elect to pay a uniform price vs. a nodal price.

A participant noted that they would like to see some additional analysis in terms of comparisons. For example, additional data regarding shadow pricing near their location as well as information over longer periods than is provided on the IESO website. In additional the information could be aggregated differently, for example, by average, by season, by comparison to Market Clearing Price (MCP), and so on. The participant indicated that they would be submitting this type of request through an official stakeholder engagement submission.

The IESO welcomed the information request and encouraged the participant to make the request as specific as possible to allow the IESO to respond.

A participant asked if for certain periods of time a dispatchable load goes non-dispatchable, whether the load can switch from uniform pricing to nodal pricing and be settled differently based on their choice.

FTI said that it's a question of equity and fairness. As the market gets more dispatchable load on the system, should a subset of load choose between two prices and choose the lower of the two? FTI pointed out that by doing that, there could be consequences for the remaining load on the system.

The participant followed up, noting that load could be adding a lot of risk here. Dispatchable loads may opt to have a bilateral contract with a generator, and non-uniform pricing could add additional complexity.

FTI agreed this needs to be addressed. Financial Transmission Rights (FTRs) might be a solution if dispatchable load wants to be able to contract with a different supplier and there is a desire to preserve the marginal incentive for dispatchable load to participate in this market while also allowing them to manage their risk and control cost shifting.

The IESO noted that this discussion is intimately tied to a day-ahead market, which is a discussion that will begin this fall.

A participant asked how "efficient" (as used in Slide 11) is defined.

FTI indicated it means setting up a market that will operate day-to-day, hour-to-hour to supply power to load at the least supplier cost. In other words, it is the economic definition, not a cost/benefit analysis at transition.

Load Pricing - Option 2 (Slides 13-16) – Zonal pricing for all loads.

A participant noted that setting up zones is straightforward if one is looking at all elements and in service. The problem comes when there are transmission outages. If someone wants to put in place a new east/west tie, for example, there's going to be a number of outages and there might be a bubble with a relatively consistent price but now more congestion is introduced within the zone. The participant asked if ISO's take that into account that when zones are developed. Do they say, we're going to have an outage at least once a year so we're going to make that zone two zones instead of one, or do they just live with it?

FTI said other ISOs don't factor outages. But, in places that use zones, the boundaries tend to be where interconnections are weak within the zone, so there is less likely to be impact from an outage.

A participant noted the empirical data and modelling is based on data from the past, but the future can't be predicted from the past. The participant asked how other ISOs factor into their design the loss of a generator or loss of a large load. For example, do they ask the control room's opinion on how many zones they should have from a technical perspective?

FTI said ISOs have procedures – market rules – for how they create new zones and about when zones might be merged. FTI explained it can be complicated. In some ISOs the decision is up to the market participants; in others the ISO analyzes congestion patterns and uses forward-looking transmission analysis to inform the decision..

The participant asked what is being recommended in terms of zones.

FTI reiterated that today isn't about policy choices, it is just about considering the options.

Load Pricing - Option 3 (Slide 17-20) – uniform for all loads, with marginal congestion and losses.

FTI noted that because of the difference between schedules and uniform settlement price, this option would require rents and loss residuals.

A participant asked what is typically the settlement horizon for such a variance account.

FTI said that congestion rents for load are often settled monthly, though it's calculated hour-by-hour.

Load Pricing - Option 4 (Slides 21-24) — Dispatchable load charged at node, all other load charged zonally with marginal congestion and losses

FTI explained that congestion hedges may be needed to ensure efficient participation by dispatchable loads. But, if there are enough zones, there probably won't be much difference between the nodal and zonal price.

Option 5 (Slides 25-28) – Nodal price for dispatchable and uniform price for non-dispatchable load with marginal congestion and losses

FTI indicated this option would require congestion hedges or some payment to ensure efficient participation by dispatchable load.

A participant said they would like to see some analysis on what impact this would have on the market. They noted that they didn't see why giving an option of uniform price to loads that are non-dispatchable is necessarily a bad thing. The participant expects that in some locations, some loads are just going to do the math and determine if their OR revenue is going to match the extra they'll be paying to stay dispatchable and nodal. And, if that calculation yields a negative number, the load will just decide to become a uniform load. In such a case, the IESO may lose some OR participation and there's probably a market cost to that. But, there may also be some other ways those loads can participate in the market, so they aren't necessarily being cut from the market completely. The participant noted that she would like to see some analysis from the IESO as to why providing people more options might be inadvisable.

A participant agreed, noting that the fact a load's dispatchable should mean they can avoid the high prices because they can drop some load.

FTI pointed out that even though a participant can drop some load, the price is still going to be higher there in some periods. Of course, the calculation also includes consideration of OR revenue and operating reserve participation. So, the question is whether this type of system can be made to work so there's efficient incentives for dispatchable load to be providing energy and OR. It's possible to design congestion hedges or side payment to make this work and FTRs can potentially help.

The IESO the purpose today is to merely present the seven options. Once the choice has been narrowed a bit, optionality can be considered.

FTI noted that if there are particular variants participants would like to see discussed, it would be helpful if participants would let FTI know so they can be looked at in a systematic way.

Load Pricing - Option 6 (Slides 29-32) – Zonal price for dispatchable load, uniform for dispatchable, taking into account marginal congestion and losses.

FTI noted that whether this option is efficient would depend on the design of congestion hedges or payments to address incentive issues for dispatchable load. How these payments are designed could, in effect, make this the option virtually the same as option 3.

Load Pricing - Option 7 (Slides 33-34) – Uniform for all loads with average congestion and losses.

FTI explained that the main downside of this option is that loads are not being given a price signal that allows them to react to the marginal cost of transmission congestion and losses.

Load Pricing Summary (Slide 36)

FTI presented a chart to begin the analysis of which choices might be put aside, or put aside subject to some analysis, to allow the group to narrow the choices somewhat.

A participant asked whether Option 5 (nodal/uniform) could be used if there was only one zone in Ontario. The participant also wondered why this option is not being used in the US, noting that there might be a reason to use it here.

FTI indicated that the difference is qualitative – if the option is nodal/zonal, the difference between the dispatchable price and non-dispatchable price would be smaller, while with nodal/uniform the difference *would be larger. Conceptually, nodal/uniform is pretty much the same as nodal/zonal except there will be bigger differences between the price.*

A participant asked if the IESO has any idea about of number of zones that might be used.

The IESO said that at the next meeting it will bring some quantitative information on congestion and losses to help begin identifying the degree and magnitude of the potential separation between the zones.

After a discussion of Option 7, a participant noted that one of the reasons the dispatchable load model has been problematic since market opening may be because the dispatch software is not determining a shift factor for these resources. The participant indicated there are a lot of things the dispatchable load model lacks now that needs to be part of this project. They cautioned that care should be taken to avoid making a decision at an early stage that prevents achieving improvements later.

FTI clarified that the IESO doesn't calculate shift factors for non-dispatchable loads. FTI noted that the software can calculate shift factors for dispatchable loads and dispatchable generation where it is required.

A participant noted that she believed that dispatchable load resources in the current market are not modelled like a generator. There was some concern that the modelling differences may lead to difficulties as the project progresses. The participant suggested that the IESO check to see if there is any difference between how dispatchable loads and generators are modelled.

A participant commented that no options involving a uniform price should be eliminated until there's greater understanding of how many zones there might be and what they look like because that has the biggest impact.

The IESO agreed, reiterating that all options are still on the table. Once the choices start to narrow, the IESO will provide more information on each of the options.

FTI then presented a list of potential questions it believes merit empirical analysis (slide 41).

A participant noted that along with the empirical analysis, it will be important to consider what role the IESO wants dispatchable load to have in the future. The participant pointed out that currently dispatchable loads are primarily OR providers and dispatchable price takers of energy. But, changes to penalty factors may change the way they operate in the future.

In a follow-up comment the participant wondered how decisions made regarding the pricing of load may constrain the day-ahead design and whether that's been considered. The participant warned that every decision taken may close some doors in other market renewal streams.

The IESO indicated that FTI will be working with them on the day-ahead design. They also noted that both the IESO and FTI are aiming to be mindful of linkages, both known and potential.

Another participant noted that about one-third of the Market Renewal Working Group is comprised of market participants that work on new technology and on bringing new opportunities to market, so the participant is hopeful that market renewal will be robust enough to allow future market alternatives to develop.

Financial Transmission Rights – Susan Pope, FTI (Slides 42-70)

A participant asked if FTRs can be used for generators.

FTI confirmed there can be FTRs for either load or generators, but today it is focusing on them only with respect to load. FTI affirmed that, in the evolution to SSM, if reasons emerge as to why generators might need FTRs in evolution to SSM, FTRs would be considered.

A participant asked if the reason FTRs for load are being considered relates to the fact that so much of Ontario's supply is either regulated or contracted.

FTI confirmed that's a reason as Ontario doesn't have competitive retailers.

A participant sought clarification about whether make-whole payments are just to return a high price LMP load to uniform and not for taking a uniform price load down to their lower LMP?

FTI indicated they can be for both. When designing these payments there are choices about how far to go to pay loads to achieve the efficient constrained dispatch.

A participant sought clarification that with respect to the items on slide 51-52, the difference between B (Alternative (non-FTR) Mechanism: Payments and charges to loads so that the sum of the payment and their energy price is approximately uniform) and F (Payments to dispatchable loads – and possibly to loads responsive to price day-ahead – in locations with average LMPs higher than zonal price) is basically that B would be for all loads and F would be just dispatchable load.

FTI confirmed that is correct.

Market Power Mitigation – Scott Pope, FTI (Slides 1- 47)

A participant asked if the market power mitigation test is only applied to a supplier that was dispatched. If a generator never got dispatched, would the reference price test be applied?

FTI explained that with the pivotal supplier test, which can be after the fact, if the generator is never dispatched up and they aren't going to get any CMSC payments, then there is no need for mitigation. That's a fundamental difference between the way the market power mitigation works in Ontario and the *way it works in other markets. In the latter case, they look at what dispatch was and then they apply mitigation.*

In a follow-up comment, the participant noted that if a market participant had offered a more market-based price, they might have been dispatched and the power system might have been dispatched a little differently. But, if they weren't dispatched, they would just be left alone?

FTI said that this is how the IESO's current market power mitigation system operates , explaining that the current regime is focused on clawing back unwarranted Congestion Management Settlement Credits (CMSC), not necessarily on efforts to influence the MCP.

The IESO agreed that, in the current system, if a supplier isn't scheduled, it wouldn't be subject to mitigation because there would not be any CMSC to claw back. IESO staff added that in an SSM, it is important to determine market power before the dispatch is finalized because there can be an impact on the dispatch and the prices subsequent to that.

FTI noted that in SSMs, offers affect the price of everything; not just the quantity of CMSC. Applying market power mitigation after the fact would mean completely re-settling the market, which would be a huge disruption to the market.

Key Design Choices to be Made (Slides 16-18)

A participant asked for the pivotal supplier test, you talk about the supplier's output being pivotal to managing transmission congestion. Would you be raising or lowering their offer if you thought they had market power?

FTI responded that the suppliers on the constrained up side would be raising their offer price, they know the system needs them to clear that constraint. With that knowledge the generator can exercise market power by increasing their offers (to $500 or $1000 for example) and the pivotality test would say: Is it such that the system operator will have to take some of that $1000 power in order to solve this constraint?

FTI added as an example suppose there's a congestion constraint and there's only one generator who is able to serve the load on that side of the transmission constraint. That load would be pivotal because there's no way the system operator can serve that load without taking some of that generator's output. Then you can imagine there's also two small generators there, but they're so small, that even if the system operator takes all their output, there'll still be a need to take some of the high priced generator's output to meet that load.

A participant followed up that in that scenario, if the bid by that pivotal supplier is high, you would lower it, is that correct? So that it would be constrained on.

FTI responded that the system operator would dispatch it down as far as you could, but the fact that it's pivotal means you have to buy at least some of its power, so if it offered at $1000, you'd dispatch as little as you could, but it would still set the price at $1000.

In a follow up question, the participant asked if, in that scenario, do the congestion rent and losses that occur go back to the supplier or do they go to the load?

FTI responded that the congestion rent that would be collected would be the value of the power that flowed over the transmission system. So in an example where we had 100 MW of transmission into that load pocket the IESO would collect the difference between the price – let's say it was $10 outside the constrained area and $1000 in it – which would be $990 times the 100 MW of transmission, that would be the congestion rent. To take the example further, suppose we also had to take 250 MW of that generator's power – suppose load in the pocket was 350 MW and we met 100 MW of it with imported power on the transmission system but we had to buy 250 MW of power at $1000. That supplier would get $1000 for the 250 MW sold, unless mitigated.

A participant followed up by asking with respect to the congestion rent, would that be allocated to the load?

FTI responded that the congestion rent would go back to the load but that would only hedge them on that 100 MWs. If the total load was 350 MW and it was met using 100 MW by power flowing over the system and 250 MW with the power generated by the high cost supplier, they'd still be exposed to the high price on 250 MW. FTI added that if we are dealing with a small amount of MW being bought at the high price and most of it is flowing over the transmission system, there's much less of an impact on the cost of power to the loads.

IESO added that in that example, that third resource that's offering up to $1000 is taking advantage of the fact you have to take at least some of its output (that is, it is exercising market power). The whole point of this mitigation is to be able to say if that test does reveal that they are the pivotal supplier, that we wouldn't allow the market to clear that node at $1000. Through mitigation we would be replacing their offer with something that is more reflective of actual marginal value if market power was not present.

A participant asked how market power mitigation might apply if a generator's offer seems high but, in fact, it represents its true cost and the generator is not trying to exercise market power. How do you know whether someone's trying to manipulate the market or they're just reflecting their true costs?

The IESO noted the question hones in on the fact that the purpose is not to try to replace generators' actual costs, but to address situations where someone exercises market power and their offer deviates due to this knowledge.

FTI noted that the idea isn't just to replace high costs with something arbitrarily low. First the market power test is applied and if the supplier doesn't have market power, there's no need to evaluate their cost. Next the offer price is compared to the reference price, to see if the offer price is inflated. Offers that are reasonably in line with the estimated cost are not mitigated.

In a follow-up, the participant asked if ISOs contact pivotal suppliers before applying market power mitigation to try to find out what's going on, or is the test applied unilaterally?

FTI said that virtually all ISOs have rules that allow the market participant to contact the market monitor proactively to explain the situation before it is going to get mitigated.

A participant asked whether market power mitigation also applies for OR.

FTI said yes and that other ISOs routinely apply the conduct and impact test is to OR.

A participant asked if market power mitigation is ever applied where a supplier might try bid very low to suppress market prices.

FTI said yes, some ISOs have rules that apply mitigation. For those that do, there is a concern about market buying power.

Market Power Test Design (slides 19-35)

FTI described how the various tests fundamentally differ.

A participant wondered whether another approach that would work would be to determine whether a market participant did something unusual and then after the fact have the system operator issue a warning.

FTI said that ISOs don't do this because they're concerned it would lead to high prices and then it would be too late to mitigate.

Another participant brought up the idea of having a primary test and a change test with pattern recognition software being used to recognize deviations. The participant suggested doing it this way would be easier to manage than to try to redress the problem after the fact.

FTI indicated that other ISOs currently do something similar to that when they are developing reference prices. When a specific offer price is used for a considerable amount of time, in general, there's no problem. But when the pattern changes, then the ISO needs to look at it.

A participant asked if a generator unit doesn't get a capacity market obligation, are they still subject to the pivotal supplier test, or can they just bid what they want?

FTI indicated that the interaction between this market and the capacity stream is one of the things that will have to be considered.

A participant asked about the relationship between the number of nodes and how long a market run takes.

FTI said that in real-time it takes a number of minutes, which means it's a real constraint because you don't want to add five or six minutes to the lag time in the real-time dispatch. In the day-ahead market, it may only add 15 minutes or so, but that's a consideration when trying to reduce the run-time of the day-ahead market.

A participant asked is it possible in a market like ours, when you have a pre-dispatch that runs every hour, even if you were to do it before your last run of pre-dispatch, there are a number of things that happen between PD minus 1 and PD minus 2 that the control room is busy doing. So if pre-dispatch normally takes about 15 minutes, that eats up a lot of time if you have to run it twice, let alone three times.

FTI responded that while this is true, it might not involve running every step of pre-dispatch three times, so maybe adds 10 minutes or so – but it is a factor. The practice is evolving towards running it before the day-ahead market because you want to make those commitments based on mitigated prices. You don't want to run it on prices that are not going to pass that test. If you're doing intra-day commitments on an economic basis, even if it's 3 hours out, you want that economic evaluation to reflect mitigated prices. In that instance if the IESO says we're going to mitigate you day ahead, and then we clear the day-ahead market based on those offers, the participant has locked in that output and if they get scheduled and raise the offer price, they'll be penalized, so there is a discipline there. But if we're talking about output that didn't clear the day ahead, we may want to mitigate the intra-day commitment as well to make sure we're making any commitments based on mitigated prices.

A participant asked for a real life example that shows offers and some made-up threshold.

Action Item: *The IESO agreed to provide an example.*

Test and Mitigation Timing (Slides 36-39)

FTI described why the introduction of a SSM will require application of market power mitigation before the fact (*ex ante*)

Determining Ex Ante Reference Prices (Slides 40-45)

FTI described the threshold high-level tests that can be considered.

Margins and Thresholds (Slides 46-47)

FTI described how the application of either market mitigation test will require the specification of a variety of cost margins, conduct thresholds, and impact thresholds.

A participant asked what happens if the IESO is a pivotal supplier? For example, if the IESO enters into a long-term energy contract and it's actually exercising some kind of market power? How would that be resolved?

The IESO responded that with any long-term agreements, it puts participation in the market onto the party supplying the energy and requires that the participant abide by the market rules, independent of the IESO being a counter-party.

Conclusion
The IESO thanked participants and reminded them it is preparing quantitative analyses related to price formation elements for further discussion and a quantitative look at load pricing and market power mitigation. The IESO also reminded participants to submit questions and comments on matters they might want additional analysis of.

Meeting was adjourned at 3:30 p.m.

Next Meeting: September 21, 2017

Action Item Summary

Date	Action	Status	Comments
	The IESO agreed to provide a real life example that shows offers and some made-up threshold to demonstrate how the pivotal supplier test would work.		
	FTI agreed to consider whether dispatchable load can provide operating reserve (OR)and get paid nodally for the OR		
	The IESO agreed to bring some quantitative information on congestion and losses		

Date	Action	Status	Comments
	to help identify the degree and magnitude of the potential separation between zones.		
	The IESO will find out whether shift factors are used when calculating dispatchable load nodal pricing.		