Work Stream	Design Element	Options	Options Overview	Common Practice	Considerations	Interdependent Elements	Preliminary Decision	Rationale	Decision Date	Slide Reference	Overview of Options not selected
Energy - SSM	Energy Price - Congestion Component	1) Include Congestion in Pricing	- A foundational choice for moving to SSM.	Option 1		The Congestion Component design element is linked to SSM DE2 (Energy Reference Price) and, DE3 (Energy Loss Component) and collectively these components form the LMP.	1) Include Congestion in Pricing	Including the cost of congestion in the energy price is a foundational element of a SSM		http://www.ieso.ca/-/media/files/ieso/document-library/engage/ssm/ssm-20171113-preliminary-decisions.pdf?la=en , Pages 5-7 http://www.ieso.ca/-/media/files/ieso/document-library/engage/ssm/ssm-20170921-price-formation-options.pdf?la=en Paees 7 - 15	There is only one viable option for this design element.
Energy - SSM	Energy Reference Price	1) Continue to use Richview (status quo) 2) Use another location	• LMP Price does not depend on the choice of the reference location • Since market open, Richview has been used as the reference location without any adverse impacts on dispatch solutions	N/A		N/A	1) Continue to use Richview as the reference location.	Richview is close to the load centre and has a strong connection to the rest of the system. Richview has been used as the reference location for many years without any adverse impacts on dispatch solutions.		http://www.ieso.ca/-/media/files/ieso/document-library/engage/ssm/ssm-20170921-price-formation-options.pdf?la=en Pages 16 - 23	The IESO evaluated 10 potential reference locations across the Ontario grid using the following metrics: - Proportion of Ontario's peak load that is in the same electrical zone as the potential reference location - Fault level - an indication of the robustness of the voltage at a station following a disturbance; and - Number of connections to the rest of the system - an indication of the strength of the connection to the rest of the grid The IESO concluded that Richview continues to be an appropriate choice for the reference location. SSM - September 21, 2017: p. 20
Energy - SSM	Energy Price - Loss Component	1) Include cost of marginal losses in the dispatch but exclude from prices (Status Quo), 2) Exclude the cost of marginal losses from the dispatch, and 3) Include the cost of marginal losses in both the dispatch and prices Secondary Options - Calculation of Loss Factors: 1) Static Loss Factors, 2) Dynamic Loss Factors, and 3) Quasi-dynamic Loss Factors	Option 1 is complex and would require a 2- schedule and CMSC; Option 2 will increase the cost of meeting load and require changes in the design & implementation of the constrained software schedule; and Option 3 will minimize cost of meeting load without need for CMSC, improve efficiency of market price signal and reduce uplift. It would also be consistent with the IESO's current constrained schedule. Secondary Options - Calculation of Loss Factors: 1) Calculated in advance using historical data and fixed for a period of time; 2) Calculated at the same time as the schedules and prices are determined; and 3) Calculated using near-term historical data prior to the schedules and prices being determined.	Option 3, Secondary Options: Option 2	Secondary Option Considerations: • Dispatch volatility occurs when a resource's 5-minute dispatch changes frequently due to minor changes in power flow solutions without providing any economic or reliability improvements to the grid • If the issue remains, the IESO will evaluate potential solutions - which could include: -. Calculating loss factors at station or area levels (not nodally) -. Calculating loss factors in DA and PD but fix them in RT • Variable generation tie-breaking rules are linked to loss factor values. This logic must be reassed.	The energy loss component is linked to the SSM design elements for load settlement and uplift recovery.	3) Include the cost of marginal losses in both the dispatch and prices. Secondary Options - Calculation of Loss Factors: 2) The IESO should pursue more dynamic loss factors to more accurately calculate losses	• Including losses in the dispatch of generation minimizes the cost of meeting load. It also eliminates the need for make-whole payments (like CMSC) due to losses pricing and is consistent with the goal of SSM (aligning prices with dispatch). • Dynamic loss factors will provide the most accurate representation of the cost of losses for the schedule and power flow outcome. They are determined for each dispatch interval. More accurate losses means that dispatch and pricing are also more accurate.		http://www.ieso.ca/-/media/files/ieso/document-library/engage/ssm/ssm-20180523-presentation.pdf?la=en , Pages 9-20 http://www.ieso.ca/-/media/files/ieso/document-library/engage/ssm/ssm-20170921-price-formation-options.pdf?la=en Pages 24 - 34	IESO data supports the need to include marginal loss costs in dispatch & market prices:Cost of marginal losses alone accounts for a difference in average generation value of at least $5/MWh between northwest and southern regions in ~8% of all hours. Incorporating marginal loss costs into dispatch but not prices (Option 1) could create slightly less inefficient incentives, but still similar to the current 2-schedule market. Exclusion of marginal loss costs (Option 2) would ignore a factor that makes certain generators significantly more expensive and could lead to uneconomic dispatch and higher costs to Ontario. Secondary Option 1 was not selected as: Static loss factors reflect loss costs within historical sample set used to calculate the factors. Under an SSM, potential inaccuracies from static losses would directly impact energy LMPs (SSM - September 21, 2017: pp. 32-33, SSM - May 23, 2018: p. 13).
Energy - SSM	Ex Post vs. Ex Ante Pricing	1) Ex Post Pricing 2) Ex Ante Pricing	• IESO currently uses a form of Ex Post (Option 1) in the unconstrained • Option 1 is complex to implement in a way to ensure it does not lead to pricing anomalies; past implementations have sent inefficient price signals during reserve shortages or ramp constrained periods • Option 2 is consistent with the IESO's current constrained schedule and avoids sending inefficient price signals during reserve short or ramp constrained periods	Option 2		Make-whole payments (DE18), Multiple Interval Optimization (DE11)	2) Ex-Ante pricing: use the same inputs that were used to determine schedule / dispatch.	Ex-ante pricing aligns pricing with dispatch (the goal of SSM). Virtually all ISOs have adopted Ex-ante pricing. Ex-ante pricing avoids problems identified by MISO and ISO-NE with inconsistencies between ex-post pricing and dispatch requiring increased make-whole payments.			• Regardless of the option, dispatch instructions will continue to be determined on an ex-ante basis • Determining prices on a different basis than that which determines dispatch (Option 1 - Ex-post pricing) would not be consistent with the aim of aligning prices with dispatch. – Ex-post pricing can introduce discrepancies between the value at which resources are dispatched and the market clearing price. May require additional make whole payments to address differences between dispatch and settlement price SSM - September 21, 2017: p. 39
Energy - SSM	Intertie Congestion Pricing	Option 1: RT intertie settlement price for intertie transactions that differ from DAM schedules would be equal to: a) The RT internal node LMP if there is no congestion, b) When export constrained - the higher of the internal nodal LMP in RT or PD intertie LMP, and c) When import constrained - the lower of the internal nodal LMP in RT or PD intertie LMP. Option 3: RT intertie settlement price for intertie transactions that differ from DAM schedules would be equal to: a) RT internal nodal LMP if there is no congestion in PD, b) PD intertie congestion price (ICP) plus RT internal node LMP (from Option 1) if export congested, and c) Lower of RT internal node LMP or final PD intertie LMP (from Option 2) if import congested.	• Option 1 is similar to the status quo. It allows the intertie settlement price to increase or decrease relative to the pre-dispatch price determined when scheduling the intertie transactions. • Option 2 is similar to what has recently been used in the New York ISO. When the intertie is import/export congested in pre-dispatch: exports would have a price floor equal to the pre-dispatch intertie LMP, and imports would have a price cap equal to the pre-dispatch intertie LMP. • Option 3 would calculate the RT ISP using the Option 1 method in the case of export congestion, to enable traders to clear export transactions in PD by bidding above the expected value of exports. Option 3 would utilize the Option 2 method in the case of import congestion to incentivize traders to bid according to their willingness to pay. It would settle DAM schedules at a price consistent with offers of RT import supply scheduled in PD.	• Approach varies among ISOs • In other jurisdictions, ISO/RTOs offer financial transmission rights (FTR) to allow intertie traders to hedge against congestion risk in the day-ahead market. FTRs are not offered to hedge against real-time congestion.	• The introduction of a DA market will significantly reduce the volume of intertie transactions subject to RT price congestion and volatility by allowing traders to lock in prices and quantities in the DA market. • With implementation of SSM & new PO optimization, differences between PD & RT prices may not be predictable. • Option 1 method will be used to settle differences between DAM & PD schedules for exports. Deviations may be settled at prices much lower than the PD export bid.	Energy Price - Congestion Component (SSM DE1)	Revised Decision 1) The IESO has determined that it will use Intertie Congestion Pricing (ICP) Option 3, which will apply the Option 1 methodology to RT settlement in export congested hours. RT intertie settlement will be equal to the RT internal node LMP plus the PD ICP (i.e., RT Internal Node LMP + PD ICP). Option 3 will apply the Option 2 methodology to RT settlement in import congested hours. RT intertie settlement will equal the lesser of the final PO intertie LMP and the RT internal node LMP (i.e., Minimum (PD Intertie LMP , RT Internal Node LMP)).	Rationale for Revised Decision: Settlement rule will enable exporters to bid in a manner that allows them to be scheduled in PO and pay the RT intertie price (+ static ICP). This decision should help avoid foregone efficient exports while PD prices remain persistently higher than RT prices. The IESO will monitor the price difference between PD and RT after implementation.The decision will encourage importers to offer according to expected marginal value of a transaction in RT to ensure efficient scheduling results. The decision will be consistent with internal resource pricing under internal transmission constraints. Option 3 will also reduce costs associated with IOG payouts and DAM buybacks. The import offer guarantee (IOG) program in place for reliability will continue to protect importers from downside risk in RT.	#####		Option 1: Status quo approach to charge intertie transactions based on the ICP in the constrained PO and the RT internal node LMP in Ontario. The approach would not provide the best incentives to offer at the expected marginal value of a transaction. Option 1 is inconsistent with internal constrained resource settlement. Imports scheduled in RT may be eligible for RT-IOG payments, which provide reliability to Ontario by protecting imports from downside settlement risk in RT. IOGs ensure that importers are paid no less than RT offer prices. Under Option 1, increased costs can result (relative to Option 2) due to interactions between a static ICP, DAM, & RT-IOG. Option 2: Dynamic approach to charge intertie transactions based on: a) RT internal node LMP if there is no congestion, b) when export constrained - higher of internal nodal LMP in RT or PD intertie LMP, and c) when import constrained - lower of internal nodal LMP in RT or PD intertie LMP. Based on stakeholder feedback for exports about predictable high PD prices in many hours, Option 2 carries potential risk that efficient exports may be foregone when exporters' willingness to buy is not priced high enough to become scheduled. In export congested hours, a static ICP allows bidding economic export transactions at high prices to clear PD for scheduling in RT.
Energy - SSM	Supplier Pricing	1) Zonal Prices 2) Nodal Prices	• Zonal pricing would mean retaining a certain amount of constrained on and off payments• Other ISOs that previously had zonal have moved to nodal pricing for suppliers.• Nodal pricing for Suppliers is used in all other SSM ISOs• Would improve market efficiency, reduce uplift and enable improvements such as a day-ahead market	Option 2	This recommendation is inherently linked to most of the SSM, DAM and ERUC design elements around price formation and settlement.		2) Nodal Pricing	• Analysis showed significant nodal price dispersion in the NW, NE • Mixed nodal-zonal approach not recommended due to added complexity • All US ISOs pay generation nodal price for energy • Nodal pricing allows for greatest efficiency gains through stronger alignment between price and dispatch – Nodal pricing will better support operability by providing spot market incentives to provide the required flexibility		http://www.ieso.ca/-/media/files/ieso/document-library/engage/ssm/ssm-20171113-preliminary-decisions.pdf?la=en , Pages 17-19 http://www.ieso.ca/-/media/files/ieso/document-library/engage/ssm/ssm-20170921-price-formation-options.pdf?la=en Pages 58 - 70	• Reliance on a zonal pricing design for suppliers would continue to provide a barrier to implementation of a day-ahead market and hinder providing efficient incentives for the supply of flexible capacity. • For a zonal system to be workably efficient, it requires a low degree of price dispersion within all zones, not just a subset of zones as would be likely for Ontario, per the data. • The IESO analysis shows that regions such as the Northwest and Northeast would have large and relatively frequent differences between nodal and zonal prices if they were defined as zones • Some regions could be priced as zones for suppliers with very little price variation between the nodal and zonal prices • It would likely be complicated and impractical to operate an SSM with some suppliers settled nodally and some zonally to accommodate the pattern of price dispersion shown in the IESO data • A zonal pricing design for suppliers would require some mechanism to incent supply resources to follow dispatch instructions in the Northwest and Northeast • Some of the same problems with make whole payments and incentives that are present in the current design would occur, although possibly somewhat reduced in scale depending on how zonal prices were calculated. SSM - September 21, 2017: p. 68-70
Energy - SSM	Operating Reserve Reference Price	1) Co-optimize energy and operating reserve	• Only one viable option which is also the status quo			Since the OR reference price formation will have impacts on energy LMP formation in both the day-ahead and real-time markets, this recommendation is linked to the Day-Ahead Market (DAM) two settlement design.	1) Continue to jointly optimize Energy and Operating Reserve.	The IESO's current design is best practice for SSM markets.		http://www.ieso.ca/-/media/files/ieso/document-library/engage/ssm/ssm-20170921-price-formation-options.pdf?la=en , Pages 71 - 75 http://www.ieso.ca/-/media/files/ieso/document-library/engage/ssm/ssm-20171113-preliminary-decisions.pdf?la=en , Pages 20-22	There is only one option for Operating Reserve Reference Price.
Energy - SSM	Operating Reserve Price - Congestion Component	1) Include Congestion in Pricing	• Only viable option for SSM	Option 1	• This will provide a more efficient price signal for investments that would allow demand-side and storage resources to provide reserves in higher-priced regions.	This recommendation affects how OR prices will be determined and hence is inherently linked to most of the SSM, Day Ahead Market ("DAM") and Enhanced Real-time Unit Commitment ("ERUC") design elements around price formation and settlement.	1) Include the cost of congestion in Operating Reserve Prices.	Including the cost of congestion in pricing is a foundational element of a SSM		http://www.ieso.ca/-/media/files/ieso/document-library/engage/ssm/ssm-20170921-price-formation-options.pdf?la=en Pages 76 - 84 http://www.ieso.ca/-/media/files/ieso/document-library/engage/ssm/ssm-20171113-preliminary-decisions.pdf?la=en , Pages 23-25	There is only one option for Operating Reserve Price - Congestion Component.
Energy - SSM	Constraint Violations	1) Apply current penalty prices in the constrained schedule, but relax violated constraints and determine settlement prices based on incremental energy and/or operating reserve offer prices (status quo) 2) Use the same set of penalty prices for both dispatch and pricing a) Use current penalty prices b) Create a hierarchy of new penalty prices c) Create a demand curve for penalty prices 3) Apply current penalty prices in dispatch, but use a different set of penalty prices for settlement a) Create a hierarchy of new penalty prices b) Create a demand curve for penalty prices	Under all options, OR and Energy prices would continue to be capped at $2,000/MWh. ISOs operating single schedule markets have evolved away from using arbitrarily large penalty prices and towards choosing penalty values that are consistent with the cost ("reliability value") of actions the ISO would take to resolve those conditions.	Most ISOs have moved toward using transmission and operating reserve demand curves in RT dispatch.	• Having a different set of penalty prices in the dispatch and pricing run allows the dispatch to ensure compliance with reliability standards while ensuring prices are settlement ready and reflect market values. • A key driver is to ensure that operators don't have to manually make these decisions; the prices need to be set correctly to ensure the software makes the right commitment decisions. • ISOs moving toward penalty values that more closely reflect the cost or 'reliability value' of control actions.	Make-whole payments (DE18), Multiple Interval Optimization (DE11)	1) For reliability based constraints apply the current penalties in dispatch, but use a different set of penalty prices in pricing, and 2) For non-reliability based constraints, apply a new set of penalty prices in dispatch and in pricing. Constraint Violations Guidelines: 1. Constraint violation prices are determined based on either estimated cost of the service interruption that would result from the violation, the costs of resources that are typically used or could be used to avoid the violation, or the intersection of cost and willingness to pay to avoid the violation; 2. The hierarchy of constraint violation penalty prices is consistent with the order that constraints are violated by dispatch; 3. Graduated penalty pricing is used where appropriate so that as the MW value of a violation increases, the price of that constraint violation increases to reflect the increased cost and value of avoiding that violation; 4. Extreme violations that could lead to load shedding result in $2000 settlement prices; 5. Extreme violations where manual operator actions are necessary to maintain reliability will result in $2000 settlement prices; 6. For transmission limit violations that have significant impacts on system reliability, the constraint violation price should be high; and 7. For transmission limit violations that have lesser impacts on system reliability, the constraint violation price should be low.	Decision consistently and appropriately signals violations to the market at prices determined with stakeholder input and provides viable scheduling results in all timeframes. Decision also avoids violations of reliability constraints which can be resolved. Decision provides flexibility by allowing non-reliability based constraints to be exceeded, and provides prices that reflect the impact caused by scheduling.		http://www.ieso.ca/-/media/files/ieso/document-library/engage/ssm/ssm-20180718-presentation.pdf?la=en , Pages 45-46 http://www.ieso.ca/-/media/files/ieso/document-library/engage/ssm/ssm-20180523-presentation.pdf?la=en , Pages 55-69 http://www.ieso.ca/-/media/files/ieso/document-library/engage/ssm/ssm-20180329-presentation.pdf?la=en , Pages 10 - 29 http://www.ieso.ca/-/media/files/ieso/document-library/engage/ssm/ssm-20170921-price-formation-options.pdf?la=en Pages 85 - 94	• Penalty prices are favoured over constraint relaxation – Constraint relaxation results in less consistency and less appropriate pricing – Constraint relaxation can under-represent occurrence of violations • Consistency and appropriateness is improved with penalty pricing relative to relaxation, especially when it is graduated – Ensures that all violations are signaled to the market – Graduated prices consistently signal the magnitude of violation to the market – Graduated pricing avoids large price swings for minor/transient violation events SSM - March 29, 2018: pp.17-18
Energy - SSM	Out-of-market Operator Actions	1) Prevent impact of out-of-market control actions on price determination 2) Use pre-determined prices when implementing out-of-market control actions 3) Allow impact of out-of-market control actions on price determination	1. Prevent impact of out-of-market control actions on price determination Prevent control actions from distorting market prices during scarcity/surplus conditions in Ontario. 2. Use pre-determined prices when implementing out-of-market control actions Predetermined prices may be out of sync with cost of actions taken. 3. Allow impact of out-of-market control actions on price determination Price is aligned with dispatch. No special treatment is required for pricing run to differ from the dispatch run.	A scan of several other jurisdictions operating an SSM market shows that there is no single common approach with respect to allowing/preventing impact of actions on prices exists. While some jurisdictions have established rules, in most jurisdictions, no special treatment is utilized and the operator actions are allowed to impact prices which can be a distortion to market outcomes. Varies	–Price signal should accurately reflect supply/demand conditions and the capability of the transmission system –Avoid masking prevailing conditions or producing counterintuitive prices	1- The recommendation for control actions involving imposing operational restrictions on a resource is consistent with the recommendation for SSM design element: Price Setting Eligibility 2- The recommendation for control actions taken following the issuance of dispatch instructions is consistent with the recommendation for SSM design element: Ex-post vs. Ex-ante pricing	The IESO recommends that for: • For control actions taken to address scarcity conditions inside Ontario, market prices should show the scarcity condition inside Ontario that triggered the control action. The pricing pass will therefore differ from the dispatch run in these instances • For the curtailment of imports taken to address surplus conditions within Ontario, the prices should show the surplus condition inside Ontario that triggered the control action. The pricing pass will therefore differ from the dispatch run in these instances. • For control actions that change system inputs to better reflect prevailing system conditions or transmission system capability, they should be consistently modeled in both pricing and dispatch. • For control actions involving imposing operational restrictions on a resource should be prevented from setting price. This is consistent with the recommendation for SSM design element: Price Setting Eligibility • For control actions that signal resources to not follow a given dispatch, do not allow the control action to affect prices.			• The prices should avoid masking prevailing scarcity/surplus conditions inside Ontario; it applies to cases where an out-of-market action can distort market prices • The prices should align with dispatch and should reflect prevailing system conditions; it applies to actions that inform the market based dispatch solution • Control action pricing should be consistent with other SSM decisions • Properly pricing the scarcity condition encourages efficient market responses to the current and future scarcity events	#####		A single high level choice (Option 1, 2 or 3) is inappropriate for all control action types. Better addressed when considering all of the details. SSM - December 11, 2017: p. 105
Energy - SSM	Multi-Interval Optimization	1) Use MIO to determine schedules but use single interval optimization for prices (similar to status quo) 2) Use MIO to determine schedules and prices	Option 1: Similar to current design but SSM would take actual ramp rates, transmission congestion and minimum load blocks into account when calculating prices. Potential for inconsistencies between dispatch and prices. Option 2: Reduced potential for inconsistencies between dispatch and prices.	Varies (not all jurisdictions have implemented MIO)		Make-whole payments (DE18), Pre- or pos-interal pricing (DE4) Price setting eligibility (DE12), Constraint violation (DE9)	2) Use MIO to determine schedules and prices.	• Improves price signal alignment with prevailing system conditions/needs and those in subsequent intervals • Reduces frequency of required make-whole payments by ensuring that methodology for dispatch and pricing are aligned • Consistent with NYISO and CAISO, the only other jurisdictions which use multi-interval optimization in dispatch and pricing			Single interval optimization pricing (Option 1) would introduce discrepancies between dispatch and the settlement price. Also, it would depend upon make whole payments to address differences between dispatch and settlement price. SSM - November 13, 2017: p.28
Energy - SSM	Price-Setting Eligibility/Operating Restrictions	1) Do not allow any resources' restricted MW's (e.g. minimum loading point) to set or impact prices (status quo in the constrained schedule). 2) Allow fast start online resources' restricted MW's to set or impact price. ⠿	Option 1 • Would not require changes in prices determined by the constrained schedule. • Could at times set prices that would be inconsistent with the dispatch of fast starting resources with MLPs (Ontario currently has few such resources) Option 2 • Would produce marginal prices more in line with actual dispatch of fast-starting resources with MLPs in real-time • Would require changes in how prices are determined by the constrained schedule when units with operating restrictions are marginal	NYISO allows fast-start gas turbines to set price, so long as they are marginal and not simply online because of minimum run-time considerations		The price-setting eligibility design element is linked to make-whole payments design elements ("DE") in SSM (DE 18), Enhance Real-Time Unit Commitment (DE 12) and Day-Ahead Market (DE 15)	1) Do not allow any resources' restricted MW's (e.g., minimum loading point) to set or impact prices (status quo in the constrained schedule).	• Option 1 pricing is preferred for the initial SSM implementation • Unlikely to cause material misalignment of prices – IESO 2016 analysis showed that intra-hour gas-fired units were scheduled for more than 200 MW, but not setting price, in only 1% of intervals • Simpler, because SSM implementation will not require a pricing pass to enable restricted megawatts to set price		http://www.ieso.ca/-/media/files/ieso/document-library/engage/ssm/ssm-20171211-price-formation-options.pdf?la=en , Pages 106 - 110 http://www.ieso.ca/-/media/files/ieso/document-library/engage/ssm/ssm-20170921-price-formation-options.pdf?la=en Pages 116 - 123	• Best practices for implementing Option 2 are evolving with changes in resource mix, and should be clarified over the next few years as alternative designs are implemented in US ISOs • Reasons to re-evaluate the need for Option 2 in the future are known: increased real-time reliance on intra-hour units with restricted operating ranges – Such change possible with SSM pricing. SSM - December 11, 2017: p. 109

Work Stream	Design Element	Options	Options Overview	Common Practice	Considerations	Interdependent Elements	Preliminary Decision	Rationale	Decision Date	Slide Reference	Overview of Options not selected
Energy - SSM	Mitigation Process	1) Pivotal Supplier Test: Offer/bid is subject to mitigation if it is part of supplier capacity that is pivotal in resolving a binding constraint - measure of amount of competition 2) Conduct and Impact Test: Offer/bid is subject to mitigation if it exceeds competitive reference level, and has a market impact by raising the clearing prices.	Method in which to apply mitigation: Option 1 depends on complicated approximations in order to identify pivotal supply associated with a constraint, and may not capture all of the binding constraints ex-ante - potential for under mitigation Option 2 captures comparatively more of the potential market power scenarios. If market impact is identified, then mitigation is applied to all those whose offers exceeded the conduct threshold. Mitigation process requires significant processing time (needs to resolve the dispatch up to three times).	Varies by ISO: Option 1 - PJM, CAISO Option 2 - NYSIO, ISONE, MISO, SPP		Reference Levels (DE15), Timing of Application (DE14)	2) Conduct and Impact Test, where a number of secondary issues associated with this decision: i) Designated % or fixed dollar per MWh thresholds determine offer price & price impacts to trigger mitigation; ii) Narrowly Constrained Area (NCA), Dynamic NCA, or Broad Constrained Area (BCA); iii) Resource offers will be mitigated to reference levels when contributing to uneconomic production due to congestion or offering at conduct & impact thresholds; iv) Restricted competition or deemed uncompetitive interties will use pricing rules to mitigate prices; and vi Global market power conduct & impact tests will be applied for mitigation when MISO & NYISO interfaces are import constrained. Guidelines to develop specific conduct & impact thresholds during detailed design: 1. Promote market outcomes consistent with competitive participation results; 2. Account for Ontario-specific issues that can largely impact mitigation efficiency; 3. Intervene in market no more than needed to constrain material market power; 4. Not unnecessarily distort efficient incentives for market participation; 5. Balance the administration of mitigation regime maintenance against effectiveness; and 6. Become less permissive as competition is more restricted. Uncompetitive intertie designation guidelines: 1.Requires public notification prior to coming into force; 2.Applies in all timeframes (DAM, PD, RT); 3.Requires a reasonable expectation that competition restrictions exist (e.g., one participant controls bulk of trade, regulatory competition barriers, or collective behaviour) Guidelines for pricing rules on uncompetitive interties: 1.Address issues specific to DAM and issues specific to the day-at-hand; 2.Are intended to improve price fidelity on uncompetitive interties; 3.When activated, will result in intertie prices that better reflect local conditions in Ontario; 4.Are intended to reduce potential impact on uplift and FTR accounts; 5.Will account for potential issues with import & export transactions.	2) A conduct and impact test avoids the need for complex assumptions in areas such as offers of competing suppliers. It does not depend on detecting all binding transmission constraints prior to RT. Mitigation is more directly tied to (estimate of) the actual exercise of market power. Does not depend on catching all binding transmission constraints prior to RT. 2-iv) Other interties are not of sufficient size or liquidity for discipline competition.		http://www.ieso.ca/-/media/files/ieso/document-library/engage/ssm/ssm-20171221-price-formation-options.pdf?la=en Pages 21 - 46 http://www.ieso.ca/-/media/files/ieso/document-library/engage/ssm/ssm-20171113-load-pricing.pdf?la=en , Pages 29 - 32 http://www.ieso.ca/-/media/files/ieso/document-library/engage/dam/dam-enuc-ssm-20180718-mpm-design-considerations.pdf?la=en	Pivotal Supplier Test (Option 1) was not selected because of the following limitations: • If a participant is found to be pivotal, and a constraint is binding, it is mitigated regardless of its impact – Complex set of assumptions necessary to conduct the test on an ex-ante basis SSM - December 11, 2017: p. 22 SSM - November 13, 2017: p. 31
Energy - SSM	Timing of Application	1) Ex-Ante (before the fact) market power mitigation	• Because the exercise of market power in a SSM can affect market prices, mitigation needs to be done before market prices are determined. • After the fact mitigation and the subsequent resettling of market prices would be complicated and disruptive.	Ex-Ante	• While incremental bid/offers are subject to ex-ante mitigation, mitigation of start-up costs, minimum load costs, and/or restrictive operating parameters could potentially be performed ex-post (impacts are limited to uplift which can be dealt with after-the- fact).	Mitigation Process (DE13)	1) Apply market power mitigation ex-ante (before the fact).	Because the exercise of market power in a SSM can affect market prices, mitigation needs to be done before market prices are determined.		http://www.ieso.ca/-/media/files/ieso/document-library/engage/ssm/ssm-20171113-load-pricing.pdf?la=en , Pages 18 -19	There is only one viable option for the timing of the application of market power mitigation. In single schedule markets the exercise of local market power can materially impact clearing prices for all buyers and sellers within a constrained region. After-the-fact mitigation of offer prices in single schedule markets would entail resettling the entire market, which would be costly and disruptive.
Energy - SSM	Reference Levels	1) Apply principles used in today's mitigation, in order to develop reference prices. 2) Develop new principles that develop reference prices used for mitigation. Two options to determine cost-based reference levels: 1) Cost-based reference levels determined daily by the IESO 2) Cost-based offers submitted daily by participants	Mitigation process needs reference offer prices that are an estimation of resource costs (including opportunity costs). More complicated for ex-ante mitigation, as these need to be calculated before all costs are known.	Varies by market	Having the IESO determine the cost-based reference levels will reduce risk of reference level errors. MPs will have the incentive to notify and try to correct reference levels that are too low and the IESO has no incentive to use reference levels that are too high. It may be easier to get resources committed to maintaining reference levels and doing necessary audits if this work is done regularly up front (option 2 of next steps) than it would be to get resources allocated for after the fact audit. Adopting another procedure whereby MPs submit costs and are subject to after-the-fact review and audit may be sensitive given the climate regarding the recent AG report.	Mitigation Process (DE 13), Timing of Application (DE 15). DAM: a) Reference quantity will impact the ex-post assessment of physical withholding, and b) Market power mitigation will be impacted by the mitigation process selected. ERUC: a) Commitment cost mitigation will be impacted by the mitigation process as the mitigation process will determine when and how commitment costs are mitigated.	1) Apply the principles used today to determine reference prices for market power mitigation in an SSM market. Determination of the cost-based reference levels: 1) The IESO will determine cost-based reference levels on a daily basis	The principles that govern how the current regime determines reference prices and settlement adjustments are consistent with those underpinning reference prices under ex-ante mitigation regimes. Moving to ex-ante mitigation does not render the general approach adopted today unviable. However, ex-ante mitigation will require a methodology change for determining reference levels. Determination of the cost-based reference levels: • This option ensures that cost-based reference levels that are used will be consistent with the established methodology • The IESO will have the incentive to avoid cost-based reference levels that are too low to avoid unnecessary administrative burden associated with processing disputes on reference levels • Participants will be provided mechanisms to dispute underestimated costs		http://www.ieso.ca/-/media/files/ieso/document-library/engage/ssm/ssm-20171113-preliminary-decisions.pdf?la=en , Pages 35-37 http://www.ieso.ca/-/media/files/ieso/document-library/engage/dam/dam-enuc-ssm-20180718-mpm-design-considerations.pdf?la=en , Pags 17-26	• The principles that govern how the current regime determines reference levels and settlement adjustments are consistent with those underpinning reference levels under ex-ante mitigation regimes • Moving to ex ante mitigation does not render the general approach adopted today unviable • However, ex-ante mitigation will require a change in methodology for determining reference levels. SSM - November 13, 2017: p. 37 Determination of the cost-based reference levels: • Under either approach the underlying marginal cost of the facility, the 'target' of the reference level, remains the same • Under either approach the IESO, in consultation with market participants, must develop and document a methodology for determining cost-based reference levels including estimates of opportunity costs • However, Option 1 also ensures that cost-based reference levels that are used will be consistent with the established methodology SSM - July, 2018: p. 17-26
Energy - SSM	Pricing for Loads	1) All loads pay the nodal price at their location. Prices include the marginal cost of losses and congestion. 2) All loads pay the zonal price, at the zone associated with their location. Prices include the marginal cost of losses and congestion. 3) All loads pay the province wide uniform price. Prices include the marginal cost of losses and congestion. 4) Dispatchable loads pay the nodal price, while non-dispatchable loads pay the zonal price. Prices include the marginal cost of losses and congestion. 5) Dispatchable loads pay the nodal price, while non-dispatchable loads pay the uniform price. Prices include the marginal cost of losses and congestion. 6) Dispatchable loads pay the zonal price, while non-dispatchable loads pay the uniform price. Prices include the marginal cost of losses and congestion. 7) All loads pay the province wide uniform price. Prices include the average cost of losses and congestion.	Load pricing options are based on 3 fundamental questions: 1) Does the load price include the marginal or average cost of congestion and losses?• will decide if congestion and loss surpluses which can be used to fund FTRs or a uplift disbursement 2) Will dispatchable and non-dispatchable loads be settled at the same level of granularity? (nodal, zonal, uniform)? • If different, may require a incentive mechanism to maintain amount of DL 3) What is the applicable pricing granularity to the price (nodal, zonal, or uniform)?	Variants of Option 4 seem to be the most common.			4) Dispatchable loads pay the nodal price, while non-dispatchable loads pay the zonal price. Prices include the marginal cost of losses and congestion. For non-dispatchable load, Zonal Pricing with a nodal option for a period of one year. The default will be for NDLs to pay a zonal price. The IESO proposes 10 load pricing zones.	Rationale for Dispatchable Resource Pricing) Nodal pricing for dispatchable resources is the best way to encourage efficient bids and thus ensure efficient dispatch outcomes: If zonally priced, there could be a misalignment between zonal prices and the nodal dispatch outcomes. When such misalignment occurs, a system of out-of-market uplift payments would then be needed to ensure dispatchable resources follow dispatch when zonal and nodal prices diverge. To avoid creating inefficient bidding incentives dispatchable resources should be settled at the same price granularity in both day-ahead and real-time. Rationale for Non-dispatchable Resource Pricing) Zonal pricing is a more efficient option than uniform pricing. The definition of load zones match major and expected Ontario system constraints/congestion An approximation of nodal pricing for NDL) Nodal/zonal pricing provides the incentives for participants to respond to locational price signals. Such signals enable locational responsives that can reduce system costs in a manner that is unavailable under uniform pricing Rationale for NDL Zonal Boundaries) Load zones correspond with Ontario's 10 electrical zones. Zonal boundaries should encompass sets of nodes with similar impacts on: Congestion on transmission constraints that could result in material cost discrepancies, even if constraints are expected to bind infrequently. Such boundaries support efficiency by: – Causing loads in different regions to pay prices reflecting differences in cost of meeting load – Efficient short-run signals for NDL – Efficient long-run pricing signals for the location of energy intensive economic activities		http://www.ieso.ca/-/media/files/ieso/document-library/engage/ssm/ssm-20180130-load-pricing.pdf?la=en , Pages 9 - 34	Options 1-3 & 5-7 were not selected for the below reasons: • Nodal pricing for dispatchable resources is the best way to encourage efficient bids and thus ensure efficient dispatch outcomes – If zonally priced, zonal prices and the nodal dispatch outcomes could be misaligned – When misalignment occurs, a system of out-of-market uplift payments would then be needed to ensure dispatchable resources follow dispatch when zonal and nodal prices diverge • To avoid creating inefficient bidding incentives dispatchable resources should be settled at the same price granularity in both DA and RT • Nodal/zonal pricing provides the incentives for participants to respond to locational price signals. Such signals enable locational responsives that can reduce system costs in a manner that is unavailable under uniform pricing • The residual disbursement methodology may be able to offset some cost impacts of moving away from a uniform price while keeping the marginal incentives needed to respond to regional prices (SSM - January 30, 2018: Pages 9 - 34).
Energy - SSM	Congestion Rents & Loss Residuals	Options for Zonal Disbursement:1) Relative Zonal Price (frequency of disbursement options: monthly, quarterly, semi-annual, annual); 2) Volumetric; and 3) Expenditure-based Options for In-Zone Disbursement: Option A - Static allocation: Proportional to its share of a static allocation of consumption in the zone with respect to other loads in the zone Option B - Share of consumption for the month: Proportional to its share of actual monthly consumption in the zone with respect to other loads in the zone Option C - Share of energy expenditure for the month: Proportional to its share of the total cost of energy that is in excess of the cost at the uniform supplier weighted price for that month with respect to other loads in the zone. Similar concept as Zonal Disbursement Option D – More granular assessment of share of energy expenditure for the month: Compares a load's total monthly cost under nodal/zonal pricing to what its cost would have been under uniform pricing. Similar concept to Option C. Assessment is performed on an interval basis using a uniform price applicable to that interval (varies by interval). Loads in the zone receive an allocation based on relative impact of nodal/zonal vs. uniform.	1) Relative Zonal Price methodology: residuals are disbursed only to zones which have a higher load-weighted price than the system-wide supply-weighted price, proportional to zonal expenditure 2) Volumetric methodology: residuals are disbursed to all zones proportional to respective zonal consumption - i.e., zonal consumption relative to total Ontario demand 3) Expenditure-based methodology: residuals are disbursed to all zones proportional to respective total zonal energy charges - i.e., zonal total energy costs relative to total Ontario demand	This is a non-traditional method of disbursing the congestion rents and loss residuals (typical application is to provide node to node congestion hedge).	• Address the move away from province-wide pricing for wholesale loads - while still encouraging the efficiency benefits of zonal pricing - Load weighted zonal price > Supplier weighted uniform price • The disbursement will not result in higher price zones having a lower price (net of residuals) than the uniform supplier weighted price • Process should preserve the marginal incentives of the price signal – Loads should still be encouraged to respond to locational prices – A quarterly disbursement is unlikely to interfere with loads' marginal incentives to be price responsive	• Choices are dependant on which load pricing option is decided upon (will vary the incentive or efficiency issues that need to be addressed)	Decision 1) The residual from congestion rents and marginal losses from both the DA and RT balancing markets will be used to fund the Residual Disbursement process. Decision 2) Zonal Disbursement will be based on Relative Zonal Price: This method returns residuals to zones with prices that are higher than the Ontario average during the allocation period. Load weighted average price for the zone will include both nodal and zonal price loads. The IESO proposes calculating and distributing residuals among loads in those zones on a quarterly basis. The IESO proposes this approach to be a permanent solution. Decision 3) In-Zone Disbursement will be based on (Option D) the relative difference between a load's expenditure across a 3-month (quarterly) timeframe using: Loads' Applicable Settlement Price - Nodal Or Zonal (in the interval); and Quarterly Uniform Supplier Weighted Average Price In The Province (in the interval). In-Zone Disbursement will be done relative to all other loads in the zone. Loads with a settlement price that is lower than their average uniform price, will not receive a portion of the residual. Decision 4) A limit will be applied to the zonal and in-zone disbursement to ensure that no load is settled at an overall quarterly price that is less than what their quarterly cost would have been under uniform pricing.	Rationale for Decision 1) The residual can be utilized to mitigate impacts on Ontario loads of moving away from a uniform price. Rationale for Decision 2) Allocating on the basis of Relative Zonal Price is an effective way to addressing the move away from province-wide pricing for wholesale loads - while still encouraging the efficiency benefits of zonal pricing. The IESO recommends that the residual calculation and disbursement be conducted on a quarterly basis. This reduces adverse locational price impacts relative to those under monthly disbursement. Quarterly calculation and disbursement results in prices closer to the pre-residual price than with a monthly calculation. It is expected that it is harder for consumers to predict residual amounts allocated quarterly, thus the impact of the residual on their RT consumption decision will decrease. Quarterly calculation and disbursement provides for an improvement over monthly disbursement, while allowing to return residuals sooner to market participants than with semi-annual or annual frequencies. Rationale for Decision 3) Option D recognizes that individual loads have different load patterns and allocates residuals in recognition of those differences. All loads benefit proportionally to their impact. In-zonal share is directly tied to when a load consumed and its contribution to the residual, all relative to the experience of other loads in the zone. While option D is the most direct method for in-zone disbursement, the overall mechanics of the process are intended to avoid adverse impacts to marginal incentives. Rationale for Decision 4) Disbursement process is limited to only addressing the impact of loads moving to a nodal/zonal price.			Discounting of Options using FTR Mechanisms: In Ontario, loads are supplied from scheduled generation in the wholesale market; no direct relationship between loads & generation sources could serve to define the transmission path as the basis of an FTR. It is difficult to develop FTR allocation modeling that could correlate FTR assignments with potential impacts from LMP pricing. A static FTR would not accurately capture LMP pricing impacts on loads. FTRs could produce payouts even if a load did not consume and was not impacted by congestion costs. Discrepancies between FTR allocation and load consumption could result in loads being over/under compensated. Discounting of Secondary Options for Zonal Disbursement: All 3 methodologies have lower price outcomes for all zones compared to status quo, but Relative Zonal Price allocation was selected as the more effective way to address the move away from province-wide pricing based on IESO analysis. The IESO will examine the interaction between nodal/zonal load pricing & residual disbursement in detailed design. Discounting of Secondary Options for In-Zone Disbursement: Options A & B are not dynamic enough to align with timing & cost of load consumption relative to a uniform price. Options do not disburse residuals relative to a load's increase in cost relative to being settled at a uniform price. With Option C, load allocations based on a province-wide quarterly average uniform price. This reference does not necessarily identify a load's increased cost from moving away from a uniform price (SSM - September 20, 2018: pp. 12, 18, SSM - May 23, 2018: p.21, p. 43).
Energy - SSM	Make Whole Payments	1) Provide make whole payments for dispatch-up and dispatch-down scenarios 2) Provide make whole payments only for dispatch-up scenarios	Options address compensation that may be required when a resources' dispatch is not in line with the prices at its location. A resource may be dispatched-up to provide ramp in a later interval (potentially incurring an operating loss). OR dispatched-down to allow, for example, a fast starting gas-fired unit to come online (need to respect the minimum load of the gas unit) - potentially incurring an opportunity loss	Option 1		Energy Price - Loss Component (DE3), Constraint Violations (DE9)	1) Provide make whole payments for dispatch-up and dispatch-down scenarios.	Including make whole payments to both dispatched-up and dispatched-down suppliers creates appropriate incentives for resources to follow the IESO dispatch instruction, resulting in greater operational certainty for the IESO. In general, make-whole payments will no longer occur because of transmission congestion. Also, make-whole payments are likely offset by OR revenues, where applicable. Apporach is consistent with most other jurisdictions (with the exception of PJM).			• Option 1 creates appropriate incentives for resources to follow IESO dispatch instructions (better operational certainty for the IESO). • Option 1 is consistent with most other jurisdictions (with the exception of PJM) SSM - November 13, 2017: p. 40
Energy - SSM	Uplift Recovery	1) Distribution of congestion rents and marginal loss surplus will be based on the per MWh of actual withdrawals by internal loads 2) Distribution of congestion rents and marginal loss surplus will be based on the per MWh of actual withdrawals by internal loads and exports	New types of payments (associated with congestion rents and losses) will need to be distributed to (or recovered from) market participants.	Varies	Currently, make-whole uplift is assigned on an hourly basis: - Continues to be an important principle to retain, as it causes this uplift to be disbursed based on a principle of cost causality - Consumers (Ontario loads and exports) which benefited as a result of their consumption in a given hour should cover any imbalance of costs in that hour	Congestion Rents and Loss Residuals (DE17)	Decision 1) The residual from congestion rents and marginal losses will be allocated according to the methodology outlined in Design Element #17 - Congestion Rents and Loss Residuals. The residual from congestion rents and marginal losses is to be disbursed to loads to mitigate the impact of moving to a non-uniform price. No decision regarding the uplift of the residual is required. Decision 2) Uplift associated with intra-hour make-whole payments will be allocated hourly on a per MWh of actual withdrawals by Ontario load and exports.	Rationale for Decision 1) Proposal is to disburse the residuals in a manner that serves to mitigate the impact to loads of moving to a non-uniform price. Rationale for Decision 2) - Intra-hour cost as a result of make-whole payments are distributed based on a principle of cost causality - These are unrecovered costs that are a necessity as a result of delivering energy and scheduling operating reserve - Benefits are proportionally shared between load consumers and exports consuming in that hour		http://www.ieso.ca/-/media/files/ieso/document-library/engage/ssm/ssm-20180523-presentation.pdf?la=en , Pages 55-69	Preliminary Decision #1 Proposal is to disburse the residuals in a manner that serves to mitigate the impact to loads of moving to a non-uniform price. Preliminary Decision #2 - Intra-hour cost as a result of make-whole payments are distributed based on a principle of cost causality - These are unrecovered costs that are a necessity as a result of delivering energy and scheduling operating reserve - Benefits are proportionally shared between load consumers and exports consuming in that hour" SSM - May 23, 2018: p. 62, 67