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Allocation Methodology	**Separation Space** **Should Separation space be treated as common space?**	According to the 2005 OEB Methodology, separation space is currently treated as part of the Communication Space and is fully allocated to the Telecos. CSA C22.3 No.1 relates to the separation space for minimum clearance from the lowest Dx wire to the highest Teleco attachment. ESA Guideline for Third Party Attachments clearly defines the need for separation space for safety of communication workers as required by Ontario Regulation 22/04 – Electrical Distribution Safety. At meeting #4, it was also identified that this space is needed to ensure clearance between power and Teleco wires because of line sag during peak summer months and ice loading in the winter.	No, it should be treated as part of the Communication space. As with any cost allocation issue before the OEB, the key principle that should be applied is "cost causality" – i.e., what causes or gives rise to the need for the Separation space. Applying this principle, the Separation Space should be treated as part of the Communication Space since if there was no need to make any allowance for Teleco (i.e., third party attachers) space on the pole there would be no need for the Separation Space

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	Equal Sharing **Should the principle of allocating Common space costs equally between Telecos and LDCs as set out in the OEB 2005 Decision continue going forward?**	The Equal Sharing principle is based on the equal needs of both the Telecos and LDCs requiring ground clearance and buried space. The OEB has historically adopted equal sharing of all the costs related to the Common space. For a standard 40 foot pole, this principle results in an allocation factor of 33.6% (assuming an average of 1.4 telecom attachers) of total indirect costs. An alternate allocation principle used in other jurisdictions is the proportional principle, which does not allocate any costs related to Common space back to the Teleco attachers. This results in an allocation of 22.4% - assuming 1.4 Teleco attachers. This principle assumes that the Teleco attachers do not put any additional burden on the pole in terms of cost or maintenance.	Before commenting on this issue, it should be noted that the description of the "proportional principle" appears to be incorrect. The description suggests that under the proportional principle none of the costs related to the Common space are allocated to the Teleco attachers. However, Slide #6 from the Nordicity presentation at the May 2016 PAWG meeting indicates that based on this principle 22.4% of Common space is allocated to each attacher (assuming 1.4 attachers – i.e. 31.3% /1.4). The Equal Sharing principle should be used to allocate common space between Telecos and LDCs. The use of the "Proportional principle" would suggest that the requirement for common space is "proportional" to the specific requirement for Power and Teleco space. However this is not the case as both the Clearance Space and Separation Space are fixed amounts that are not dependent of the specific space that is assigned to Teleco (and other third parties) or Power users. Since there is no "cost causality" basis for using the proportion principle – the "Equal Sharing" principle is the fairest way to share the cost of the Common space.

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Costing Inputs	**Default Values** **The cost data collected from the LDCs participating in this consultation and submitted as part of the Hydro One, Toronto Hydro and Hydro Ottawa recent OEB Decisions (Three Decisions) can be used to create default values. As an interim step should these values be used to reset the provincial pole attachment charge that can used by LDCs?**	The cost data collected from the LDCs participating in this consultation and the Three Decisions represents more than 95% of the provincial joint use pole population. This sample size provides a significant advancement in data quality. There was a high degree of similarity between the projections by OEB staff and Nordicity (presented in the 4th PAWG) in the calculation of the pole attachment charge. The OEB/Nordicity estimates provide a logical basis for the calculation of pole attachment rates, at least on an interim basis. Data filings in future LDC rates applications will result in additional data quality and accuracy of pole attachment charges for individual LDCs.	There are a number of associated unstated issues that need to be addressed in conjunction with the matter of default values. Assuming that any new approach to setting pole access rates is implemented starting in 2018, there are two reasons why default values could be needed. The first is that under the Board's current regulatory framework for electricity distributors the majority of utilities will be in the middle of their Custom or 4th Generation IR Plan (or be one of the few utilities currently on the Annual IR Index plan) where the annual rate application is intended to be mechanistic, i.e., requiring minimal regulatory review. If the Board decides that the "update" to reflect the new methodology should occur prior to the next rebasing application then, from a regulatory efficiency perspective, it may be desirable to use "default" values to set the rates until the utility's next cost of service review. (Note: For those utilities on the Annual IR index, since there is no "scheduled" timing for a cost of service review, a decision will be required as to when/how the miscellaneous charges (including pole assess rates) will be updated). Default values used for this purpose would be "transitional" and only be in effect for a limited number of years (i.e. until rebasing occurs). Under such circumstances, one approach would be to set a default "rate" that would apply until rebasing. If a default "rate" is to be used, it should be based on the HONI and Hydro Ottawa decisions, as these values were subject to fully review and regulatory scrutiny by the Board. This would suggest that the default rate would be in the range of \$37 to \$53.

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			However, as the comments on the following issues will indicate there is significant variation across even the five utilities surveyed by Nordicity for the PAWG in values for some of the critical inputs to the pole access charge (e.g. capital cost per pole, depreciation cost pole and some categories of maintenance costs). Given that some of these costs are already tracked and reported to the OEB (i.e., via RRR data), an alternative would be for the Board even during the transition period, to use utility these specific audited costs where available and employ default values in instances where the required info is not available and/or it will have a minimal impact on the overall result. While this would be administratively more burdensome, it would result in rates during the transition that that are more reflective of each utility's costs. Responses to the subsequent issues address when default values would be appropriate and what they should be. The second reason for using default values is that even when utilities are required to make a "rebasing or cost-of-service" application and are in a position to propose pole access rates based on their specific costs, they may not have all the data required. This situation is particularly likely to occur in the first year or two after the policy is introduced. Depending upon the materiality of the "costs" involved and the difficulty in assembling utility specific data it may be appropriate to permit utilities to use "default" values set by the Board that would apply to specific factors/elements used in the "approved" rate methodology. Also, it was evident from the PAWG meetings where the utilities are all not categorizing all the costs in the same ways – further adding to the possible

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			need for default values during the initial years as utilities implement standardized definitions. However, it is important to recognize that In such cases the default values could impact the resulting rates for a longer period of time and, as a result, the use of default values should be more limited. The Board, as part of the approved rate methodology, should set out it expectations as to for what elements of the rate methodology it is expected that utility specific values will be used and when the use of default values is appropriate. Again, the responses to the subsequent issues address when and what the appropriate default values would be in such circumstances.
	Direct Administrative Costs **Should a weighted average of $2.85/pole be used as the default value? This value is based on the Three Decisions.**	Administrative Costs - directly associated with managing and administering Teleco pole attachments, such as permitting, licensing, payroll, vehicle, OM&A support services.	It is understood that administrative costs associated directly with providing third party access to utility poles are generally not specifically tracked by utilities. Also, administrative costs make only a small contribution to the total costs that would factor into the pole access charge. As a result, it would be reasonable for utilities to use a default value both during the transition and for purposes of any eventual utility specific calculation of the rate during rebasing. However, use of the weighted average cost for the three cases noted (Hydro One, Hydro Ottawa and Toronto) is questionable for several reasons. First the values used to determine the average vary widely from $0.90 to $5.03.

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			Second, only two of the cases were formally adjudicated by the OEB (Hydro One and Hydro Ottawa Third, in the case of Hydro One, the values used simply represented the value approved by the Board in its 2005 Decision escalated by inflation. Fourth, all of the values are based on historic costs (e.g. 2013 in the case of Hydro Ottawa) and will be materially outdated by the time the new rate methodology is implemented (e.g., 2018). Of the three, the Hydro Ottawa value ($2.28) was the only one that was based on a utility specific assessment of the costs involved and reviewed by the OEB. Escalating this value to 2018 (using 2%/annum) would yield a result slightly over $2.50. While not out of line with the suggested value of $2.85 it represents a more appropriate value and is the one that should be used when/if a default value is required for 2018.
	Direct Cost Loss In Productivity (LoP) **Should a weighted average of $3.30/pole be used as the default value? This value is based on the Three Decisions.**	LoP - costs associated with field verification cost of pole replacement.	Again, it is understood that LoP costs associated directly with providing third party access to utility poles are not necessarily specifically tracked by utilities. Similarly, such costs make only a small contribution to the total costs that would factor into the pole access charge. As a result, it would be reasonable for utilities to use a default value both during the transition and for purposes of any eventual utility specific calculation of the rate during rebasing. Again, it is noted that the proposed $3.30 value is based on three cases that suffer from the same shortcomings as those noted above in the discussion regarding administration costs. Again relying on the Hydro Ottawa values (for the same reasons as noted above) yields an LoP value of $3.40 based on on 2013 $ (i.e,, $121,431 in costs and 35,663 poles per the EB-2015-0004 Decision, page 10). Escalating this to 2018 at

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			2%/annum would yield a value of $3.75 which represents a more appropriate value to use for default for utilities in transition in 2018. However, the $121,431 in LoP costs approved by the Board specifically excluded $188,988 for the cost of returning crews as this was deemed to already be included in the distribution rates. As a result, the LoP value used in any rebasing of the pole access charge should also include these costs (which would then be excluded from the determination of distribution rates). The inclusion of these costs (using Hydro Ottawa values) adds over $5 to the LoP cost per pole. As a result, for purposes of rebasing utilities should be encouraged to develop utility specific values using an approach similar to that employed by Hydro Ottawa in its EB-2015-0004 Application.
	Indirect Costs - Deduction Power Specific Assets (USoA #1830) **Should a range of 15% to 18.2% be used as a default value?**	In the Hydro One and Toronto Hydro Decisions the deduction for power specific assets was set at 15% of pole costs; In the Hydro Ottawa Decision, the deduction was set at 5% because of the use of brackets instead of cross arms. 15% is consistent with the American Public Power Association (APPA) and FCC decision in 2000 (FCC-00-116) for electric utilities and New Brunswick Power Decisions. The 18.2% value was derived by Nordicity using the PAWG submissions.	Again, it appears the cost of power fixtures versus poles is not something that is normally tracked by utilities and must be estimated separately. As a result, a default value will required during the pre-COS Application transition phase and may also be required for the actual rebasing applications themselves. It is not immediately clear how Nordicity determined the 18.2% average given only two utilities provided complete data (HON and Hydro Ottawa – Nordicity November 2016 presentation, slides 10 & 11) and where i) the HON value is calculated as 17% but HON recommends using 15% to allow for some non-included pole costs and ii) the OEB approved values for Ottawa is 5%. The use of 5% vs. 15% has roughly a 10% impact on the rate calculation. As a result, it is

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			suggested that, since 15% is the more commonly accepted value, it be used as the default during the "transition" period unless the utility specifically identifies that its system uses predominately brackets – in which case the default would be 5%. Given the materiality of this factor, at the time of rebasing, utilities should be directed to undertake an analysis similar to that used by HON for purpose of providing its input to the Nordicity calculations (as circulated by OEB Staff on January 16, 2017).
	Indirect Costs - Net Embedded Cost per Pole (USoA #1830 less Accumulated Depreciation) **Should $1,077.93/pole be used as the default value? The value is calculated using the 5 year average of the data submitted by PAWG LDCs.**	The default value of $1,077.93/pole compares well with the average net book value of 10 LDCs (large, medium, small) based on actual 2015 data of $1,232. Nordicity has estimated this cost to be $1,227/pole based on a 10 year average data submitted by PAWG LDCs.	As noted already, the net embedded cost per pole used in the calculation is a major determinant of the overall pole access charge and, as evidenced by the excel file that accompanied the request for comments (see Nordicity Tables Tab, Rows 89 & 93), the cost per pole varies widely (i.e., highest value exceeds lowest by more than 100%). Furthermore, the overall value of a utility's poles is readily available from utilities' accounting records. Finally, the number of poles that a utility has should also be a readily available statistic. Given these factors, a default value would ideally not be used in determining the net embedded cost per pole during the transition phase and should definitely not be when the utility files a COS application for purposes of rebasing. During the transition period the value used could be based on each utility's most recent year's audited results since similar cost data is already required to be filed with the OEB. However, at the time of rebasing the values used should be each utility's forecast for the cost of service's test year (i.e., the same values as will be used in the determination of distribution rates).

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			Furthermore, we are concerned that only historic date has been reviewed to determine the net embedded costs that would apply to a future pole attachment rate. A number of Custom IR applications have been approved by the Board in recent years which include pole replacement costs. No attempt has been made to determine if the past trend is similar to the future trend even though it has been raised by the ratepayer groups repeatedly during the PAWG meetings. Significant capital programs have recently been approved in a number of large utilities' cases (Toronto Hydro, Horizons, Hydro One) which would appear to indicate pole replacements are increasing at a higher rate than in the past which would likely mean high net embedded cost per pole than the 2015 historic number. Finally, while not the preferred approach, if the Board determines that, at the time of rebasing, poles access charges should derived based on historical costs then the values used (i.e,., cost and pole count) should be those from the most recent historic year available. There is no regulatory precedent in Ontario for the use of historical averages (as suggested by this question) for purposes of setting rates for either electricity consumers or miscellaneous charges. Indeed, even the use of the most recent historic data would introduce a disconnect between the basis for the pole costs used in setting the rates for electricity consumers versus other users of a utility's poles. It is noted that request has not included Depreciation as an issue. However, the preceding comments are equally applicable to the determination of the depreciation expense

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			that should be used in the determination of the pole access charge for both the transition period and any subsequent rebasing/cost-of-service application. [**Note to Board Staff – average pole cost calculation in OEB excel file is incorrect –uses incorrect value for average # of poles for HON.**
	Indirect Costs - Cost of Neutral (USoA 1835) **Should the cost of the neutral wire be added to the capital cost of the pole? If yes, should a default value of $341/pole, assuming a 28% allocation, be considered? The values are based on PAWG data submissions by Hydro One and Hydro Ottawa.**	No precedent in any jurisdiction to add this cost. Not included in OEB 2005 Decision. However, a case can be made for sharing this cost with Telco's based on the following arguments: 1) CSA Standards require communication facilities to be bonded to the neutral at a minimum of every 300 meters, 2) ESA Guideline for Third Party Attachments requires no undue hazards, 3) 2016 Kinetrics study indicates Telcom bonding to LDCs neutral within 300 metres can keep induced voltages on communication cables under acceptable limits. Without this bonding there would be considerable safety risk to worker/public safety and equipment damage. Bonding typically occurs every 3rd	There are effectively three issues here: i) should the cost of the neutral be included in the derivation of the pole access charge; ii) should a default value be established for purposes of the transition period or for both the transition period and the eventual rebasing application and iii) if so, what should the default value be based on? With respect to the first issue - If 3rd party users such as telecos do bond their facilities to the utilities neutral for purposes of worker/public safety and to prevent equipment damage then they do derive a benefit from the neutral and should bear a portion of the costs. The cost of Neutral is not specifically recorded in the USoA prescribed for electric utilities. As a result, there is a need to provide for default values – at least during the transition period prior to a distributor's next rebasing/cost-of-service application. However, estimates as to the cost of the cost of the Neutral provided by Hydro One and Ottawa Hydro suggest that inclusion of these costs could have a material impact on the overall rate. Also, the Hydro One methodology suggests that the cost of the Neutral could vary widely depending upon a utility's the mix of single phase, two-phase, three phase and

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		pole. Assuming equal sharing of this cost, 28% was may be appropriate.	sub-transmission circuits. This would suggest that for purposes of rebasing the derivation of the pole access charge should be based on utility specific costs using a methodology such as that employed by HON and forecast cost for the test year. The $341 default value proposed in the question is based on 28% of the average costs recorded in HON's Acct. 1835 over the period 2010-2015. There are three concerns with this value. The first is that it ignores the analysis provided to PAWG by Hydro Ottawa. The second is that it is not based on the most recently available cost data (i.e. 2015) and the third, is .that there is no inflation adjustment to align the default costs with the test year (e.g., 2018). While it is reasonable to establish the %'s of costs attributable to the Neutral using a number of years of historic data the actual costs used in the calculation should reflect the most recent costs and pole count available (i.e., those for 2015) and be escalated at inflation (e.g., 2%/annum) to align with the year the new rates are first introduced. Furthermore, it not clear why Hydro Ottawa's data should not also be used in developing the initial cost value for 2015 using a weighted average approach.
	Indirect Costs - Maintenance of Pole (USoA #5120) **Should $6.80/pole be used as the default value for costs contained in account**	The $6.80/pole is based on taking a weighted average of the data submitted by the PAWG and is comparable to the costs approved in Hydro One & Hydro Ottawa Decisions of $4.69/pole and $11.89/pole respectively. Averaging these results would yield $8.29/pole.	As maintenance costs specifically related to poles (versus other fixtures) are not recorded separately it is likely that some default value/approach will be required at least in the transition period prior to any rebasing or cost-of-service application. However, as stated in the description of the issue the $6.80 is based on the weighted average of the PAWG data from 5 utilities and is based on 48.5% of the weighted average per

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	5120?		pole cost from Account 5120. An inspection of the supporting excel file indicates that the average maintenance cost per pole for the five utilities varies from $2 (Horizon) to $17 (London). Given this wide variation it is questionable whether use of an average value is reasonable. An alternative approach for the transition period would be to apply a default percentage to the costs recorded in the distributor's Account 5120, which should be readily available and easily verifiable. Since maintenance costs can vary from year to year depending upon resources required for other activities, it would be reasonable in this case to use a historical average and then escalate the value to the initial test year to account for inflation. However, use of six years (2010-2015) as suggested by Staff's proposed value may be too great and a four year average would be more appropriate. In terms of the default percentage to be applied to separate out pole specific maintenance, it is noted that the 48.5% used to determine the proposed value is the simple average of the values submitted by HON (5%) and Hydro Ottawa (92%). The difference in these percentages is significant. As a result, while it may be necessary to use the 48.5% factor for purposes of determining a pole access charge during the transition period, for purposes of any rebasing/cost of service application distributors should be directed to establish the percentage applicable to their service area. Finally, for any rebasing/cost of service application the maintenance costs used should be those forecast for the test year so as to be consistent with the costs being used to determine the distribution rates.

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	Indirect Costs - Maintenance of Lines (USoA #5020) **Should $3.68/pole be used as the default value for costs contained in account 5020? This value is based on RRR data for the PAWG LDCs and 50% allocation.**	No precedent in any jurisdiction to add this cost. Not included in OEB 2005 Decision. Hydro One was the only PAWG LDC that submitted data for this account and suggested an allocation of 50%. Using the 50% allocation and RRR data for the PAWG LDCs results in a cost of $3.68/pole.	It is noted that Account 5020 includes a number of activities besides "distribution line patrol" which is the activity Hydro One proposes to identify and include with the 50% allocation factor. It is also noted that the RRR data used in the determination of the weighted average $3.68 value exhibits a wide variation across utilities (from $2/pole to $14/pole based on 2010-2015 data). Thus, while in principle it seems reasonable for 3rd party users of a utility's poles to contribute to the cost of line patrolling, determination of a default dollar value is problematic. For purposes of transition, an alternative approach would be to use the individual utility's average historical recorded costs per pole in Account 5020 over the past 4-5 years and apply a default percentage of 50%. The result would then be escalated to test year (e.g. 2018) based on prescribed inflation rates. At the time of the utility's next rebasing/cost of service application the cost used should be based on Account 5020's forecast costs for the test year and the utility directed to determine the percentage factor appropriate to its service area.

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	Indirect Costs - Maintenance of Neutral (USoA #5125) **In the case that the cost for the Neutal isincluded, should $1.90/pole be added as default value to the maintenance cost?**	No precedent in any jurisdiction to add this cost. Not included in OEB 2005 Decision. If one accepts the arguments for including the neutral as a capital cost, then a cost estimate of $1.90/pole for maintenance of the neutral could be calculated based on RRR data for the PAWG LDCs in account # 5125, and an assumption that the allocation provided by Hydro One of 5% is valid.	It logically follows that if the cost of the neutral is to be considered as contributing to the indirect costs for purposes of establishing the pole access charge then the maintenance costs associated with the Neutral should treated in a similar manner. It is noted that the Account 5125 values for the five utilities used in the determination of the referenced $1.90 vary significantly from $15 to $91/pole (using the 2010-2015 average costs). Given this variability the use of default value for this item is also problematic. Instead it is recommended that, for purposes of the transition period the 5% factor be applied to the utility's average historical recorded costs per pole in Account 5125 over the past 4-5 years. The result would then be escalated to test year (e.g. 2018) based on prescribed inflation rate. At the time of the utility's next rebasing/cost of service application the cost used should be based on Account 5125's forecast costs for the test year and the utility directed to determine the percentage factor appropriate to its service area.

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	Indirect Costs - Maintenance of Right of Way (USoA #5135) **Should Vegetation Management (VM) be included in the pole Attachment Charge? If yes, how should the current agreements between Teleco/LDCs be handled? If yes, should a default value of $25.60/pole be used based on data submitted by PAWG LDCs and a Hydro One allocation of 33%?**	VM was explicitly excluded from the recent OEB decisions & the 2005 methodology did not include VM. The New Brunswick (2015) decision included planned and storm-related vegetation costs about ~$13/pole. The Nova Scotia (2002) decision accepted inclusion of vegetation management costs, as it was considered an essential part of maintaining the integrity of the LDC's overhead distribution system infrastructure. The NS Board concluded that all pole tenants benefit from tree trimming, along with inspection surveys and audits, emergency repairs and pole tests.	Vegetation management benefits all users of the overhead distribution system and therefore, In principle, a portion of these costs should be included in the pole access charge. However, as noted in the description of the issue, Vegetation Management costs were excluded from the current methodology. As a result it is expected that most utilities currently recover such cost either entirely through their distribution rates or through a combination of distribution rates and separate billings to 3rd party users. Further, We do note from discussions during the PAWG meetings, and the Hydro One proceeding that many do not charge carriers at all for the service (and thus do not have any amounts to include as revenue offsets). For those who do separately bill 3rd party users, there would be double recovery of such costs if an allowance was ROW maintenance was included in the pole access charge during any transition period prior to the rebasing of a utility's distribution rates, unless the specific terms of the MEARIE agreement where such provisions are located are amended. At the time of rebasing it may be the most appropriate time for an allowance for vegetation management costs to be incorporated into the derivation of the pole access charge. As to whether a default value can be used, it is noted that the inclusion of vegetation management costs has a material impact on the resulting access charge and that the Account 5135 per pole costs used to determine the weighted average vary widely across the 5 utilities used in the averaging (i.e. $17 to $84.41 using 2010-2015 RRR data). As result the use of a default value is not considered reasonable. Furthermore, since the Hydro One value represents the upper end of the range, there is some question as to the applicability of the

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			33% factor it derived to other utilities. The fact that Hydro One has one of the more rural systems in the province also raises questions about the universal applicability of the 33% factor. At the time of rebasing utilities should determine the portion of the their forecast costs recorded in Account 5135 that are specifically attributable to vegetation management and, prior to inclusion in the rate derivation, confirm that no portion of these costs are being recovered from 3rd parties as Other Revenues.

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Rate Methodology	**Single Rate entire province versus LDC Specific** **Should the OEB set a single provincial rate?**	The current charge of $22.35 per pole per year was set in 2005 in RP-2003-0249. A comparison of the 2005 rate with the updated charges for Hydro One: $41.28/pole/year, Hydro Ottawa: $53/pole/year and Toronto Hydro: $42/pole/year demonstrates a significant difference between the 2005 charge and recently updated pole attachment charges. A similar gap for the remaining LDCs still using the $22.35 per pole charge is expected. One option to begin to address this gap would be to set a single rate for all the LDCs, or the remaining LDCs, in the interim. Correspondingly, these LDCs, along with Hydro One, Hydro Ottawa and Toronto Hydro, could then follow the annual charge adjustment process described below.	It is clear just from the data collected for the five utilities used in Staff's Work Tool that both the capital costs and the O&M costs per pole vary significantly by utility. As a result, setting a single rate for the province is clearly inappropriate as a long term solution. Indeed, even during the transition period such an approach would likely lead to a situation where the default rate was materially different than what would be subsequently established based on specific utility data at the time of rebasing. The discussion of the preceding issues has indicated an alternative approach as to how the rates could be set for individual utilities both during transition (i.e. the balance of each utility's IRM term) and upon rebasing. For the transition period, the alternative approach allows for the use of readily available historic cost data in combination with default factors to address matters such as power-specific costs. However, at the time of rebasing, when the utility will file a full cost-of-service application, the approach calls for the use of utility specific forecast costs in conjunction along with use utility specific factors to separate out (when required) the portion of the costs to be used in the determination of the pole access charge. In this regard, the recommended approach is similar to the Board's current Cost Allocation model for allocating cost to rate classes which also calls for the use of utility specific forecast costs and utility specific allocation factors. Note: A somewhat related issue it the fact that if the pole access charge policy change is implemented such that a utility's pole access charges are revised during its IRM period then this will likely result in additional revenues to the utility

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			that were not contemplated when the rates were last rebased. Such situations could be viewed as being similar to the Z-Factor events currently provide for in the Board's IR policy guidelines. While it is unlikely that revenue changes arising from the new pole access charge would trigger the materiality thresholds associated with a Z-Factor, the impact could be readily tested using the last approved COS revenue requirement application and the incremental revenue tracked in a deferral account for future refund to customers where warranted. This would be similar to the Board's approach with respect wireless attachments in EB-2016-0005.

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	Annual Charge Adjustment **Should the OEB adopt an adjustment to the Pole Attachment Charge that aligns itself with current processes? E.g. inflation minus X-factor rate adjustment (I-X).**	During PAWG Meetings No. 3 and No. 4, members agreed the Pole Attachment charge might benefit from a mechanism that would adjust the rate annually for inflationary factors. This approach could enable regular updates to the rate using an existing process and provide predictable rate adjustments. At Meeting No. 4, staff presented one such mechanism that mirrors the current LDC Annual Adjustment Mechanism: - The inflation factor is based on two weighted price indicators (labour and non-labour) which provide an input price that reflects Ontario's electricity industry. - The X-factor has two parts: a productivity factor and a stretch factor. - The OEB has determined that the appropriate value for the productivity factor (industry total factor productivity) for the price Cap IR and Annual IR index is zero. - For the stretch factor, LDCs are assigned into five groups ranging from 0.0 to 0.6%. Most efficient LDCs would be assigned lowest factor of 0.0%. All annual IR Index applicants would be assigned a stretch factor of 0.6%. - The LDC pole Attachment charge	The use of an annual adjustment factor, as described, is appropriate. Indeed, such an annual adjustment factor could be applied: • During the balance of the transition period once the pole access charge is initially determined using the approach described above. And • During the CIR or IR period after rates have been rebased. The use of an annual adjustment factor allows the pole access charge to be adjusted in an administratively easy manner during the IR period that mirrors the adjustment being applied to the utility's distribution rates and helps to moderate the changes that are likely to occur in the pole access charge when rates are subsequently rebased. For those utilities who have their rates set by CIR, it may be more appropriate to simply set multi-year attachment rates insofar as there are defined inputs. This would fairly allocated costs between distribution ratepayers and 3rd party attachers during a multi-year CIR plan where rates are known to increase at a level higher than the annual IR period adjustments.

Working Group Member Comments on Key Issues Identified During Consultation

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	Number of Teleco Attachers "Provincial Average" In the absence of LDC specific data, should a value of 1.4 Teleco attachers per pole be adopted as a default?	The data submitted for the Three Decisions and data collected from the PAWG LDCs indicate on average there are 1.4 telco attachers per joint use pole. The Three Decisions represents more than 95% of the provincial joint use pole population.	As a point of clarification it is understood that the PAWG data underlying the 1.4 attacher value included not only teleco attachers but other attachers as well (Nordicity Presentation, January 31, 2017, slide 24). Agree that, for purposes of the transition period, a default value of 1.4 would be appropriate except in those cases (HON and Hydro Ottawa) where the Board has made a specific finding. In those case the recently Board approved value should be used. However, at the time of rebasing when the utility files a cost-of-service based application the utility should be required to provide and use the value for non-utility attachers per joint use pole that is based on its service area.
Other	**Overlashing Revenues** **During PAWG Meeting No. 3 & No. 4, members confirmed that overlashers pay the current charge of $22.35/pole as well. There was no confirmation as to what the overlashers were paying the Teleco to overlash. Should there be a limit to the number of overlashers and/or weight limitation per strand?**	As each overlasher is added, incremental stress is put on the pole in terms of weight and additional maintenance. Although an overlasher pays the pole attachment charge, no charge is recovered from a Teleco who overlashes its own strand or from an overlasher who continues to add cables. Teleco could continue to overlash until pole design weight limit is met without providing compensation.	This issue appears to be closely linked to the question of whether or not the pole access charge should be on a per attacher or per attachment basis. Utility input during the PAWG meetings indicated that it would be impractical (i.e., the information regarding number of 3rd party attachments is currently not tracked) to set pole access charges on a per attachment basis. Considering it is attachments not attachers that is really the most relevant cause of costs, the Board though should seriously consider requiring utilities on a going forward basis to start collecting and tacking per attachment data so that for the next time the issue is reviewed the data is available.

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	Bell and Hydro One Agreement **Should the Bell / Hydro One agreement be taken into account in determining the Pole Attachment Charge?**	Telecos have argued during PAWG Meetings No. 3 and No. 4 that this agreement should be taken into account in determining the Pole Attachment Charge. The OEB's presentation at PAWG Meeting No. 4, slide 26, addressed this issue as follows: • EB-2015-0141, Exhibit I, Tab 4 Schedule 2 Pages 2-3, Hydro One responses to the Telecos Interrogatory 2 – confirms that no cross subsidization of cost occurs nor services provided to Bell. • In its Decision the OEB states: "Since no monies are exchanged by Bell and Hydro One, the arrangement does not impact pole attachment arrangement".	The Bell/Hydro One Agreement (and similar agreements between Bell and other utilities) give rise to a number of issues with respect to the determination of the pole access charge. The first is that since Bell is not "paying" for its use of the poles how should it be treated in the determination of the pole access charge (i.e. should it be treated as a "paying" attacher when setting the rate). In both the Hydro One and Ottawa Hydro decisions Bell was "counted" as an attacher in the derivation of the rate. This practice should continue for the new rate methodology the Board will approve. The result will be that the rate to other attachers (i.e., other telecos) will not be higher as a result of such Agreements. The second issue with whether, for purposes of establishing the contribution of the pole access charge revenues to a utility's overall revenue requirement, any revenue should be "inferred" from such Bell attachments. This issue does not impact the other telecom attachers but rather the distribution ratepayers and the shareholders of the utility. Utilities argue that such agreements benefit the utility and the utility's distribution ratepayers by virtue of the fact that it allows the utility to use Bell's poles without having to pay a monthly access fee. As long as utilities can demonstrate such benefits, there should be no need to "infer" any revenue form Bell in the setting of distribution rates. (Note: Any testing as to the benefits to ratepayers of the Bell agreements should occur at the time that rates are rebased).

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	Data Collection **During the consultation the Telecos have questioned the accuracy and quality of the data that has been collected.** **To refine the data collection process going forward, should LDCs be required to create sub accounts directly related to the pole attachment charge cost inputs?** **If yes, should the cost to create and maintain these sub accounts related to pole attachment Teleco cost allocations be added into the Direct Administrative Costs?**	This consultation has resulted in a database of cost inputs for pole attachments that is representative of more than 95% of the pole population in the province. To continue to improve the accuracy and ensure that the data remains up to date going forward, LDCs could collect pole attachment cost data within specific sub accounts. Current OEB Accounting Procedures Handbook does not require this level of granularity. Implementing this next level of granularity could bring more certainty to cost inputs and simplify future rate applications.	The comments provided to the preceding issues have recognized and attempted to address the limited data available to the PWAG group and the variability in the data that was provided. Implementing the approach suggested above will limit the use of the current untested data and allow for the full testing each utility's data when it applies for its utility specific pole access charge at its next rebasing hearing. Yes it would be useful to require utilities to create sub-accounts to directly track pole attachment charge cost inputs where such tracking is practical (i.e., the utilities internally recording keeping practices and procedures allow such cost to be identified). No. Identifying and adding such costs to Direct Administrative costs could well require as much effort as the activity itself. However, this question does raise a larger issue which is the fact that none of the alternative calculations of the pole access charge as set out in the Staff Workbook include any provision for the charge to include a share of general & administrative costs and/or general plant costs – the former being where the costs of creating/maintaining sub-accounts would be recorded. One approach would be to the use the output from the Board's CA model to identify the % mark-up on OM&A required to recover G&A costs and the % mark-up on NBV to recover General Plant costs and apply these % the costs used in the pole access charge methodology.