STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 12-T-0502 - Proceeding on Motion of the Commission to Examine Alternating Current Transmission Upgrades.

NOTICE SOLICITING COMMENTS
AND SCHEDULING TECHNICAL CONFERENCE

(Issued July 10, 2013)

On April 22, 2013, the Commission directed Department of Public Service Staff (DPS Staff) to “develop a straw proposal addressing the basis for cost recovery, appropriate mechanisms for cost recovery, mechanisms for allocating risk between developers and ratepayers, and methods for allocating project costs among ratepayers.”[1] Such a mechanism and methodology could be used to ensure cost recovery for the projects that receive approval in the comparative Article VII proceeding contemplated in the same order.

In response to the Commission’s directive, DPS Staff prepared a straw proposal for cost allocation, cost recovery, and risk allocation (Straw Proposal). The proposal further recognizes that developers may choose to pursue cost recovery pursuant to the New York Independent System Operator, Inc. tariff, as the Commission acknowledged in the April 22, 2013 Order, and provides a basis for the Commission to define a Public Policy Requirement. A copy of DPS Staff's Straw Proposal is attached.

Interested parties are asked to submit any comments electronically by e-filing through the Department’s Document and

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[1] Case 12-T-0502, Proceeding on Motion to Examine Alternating Current Transmission Upgrades, Order Establishing Procedures for Joint Review under Article VII of the Public Service Law and Approving Rule Changes (issued April 22, 2013), at 15.

Matter Management System (DMM),[2] or by e-mail to the Secretary at secretary@dps.ny.gov, on or before August 26, 2013. Reply comments, if any, may be filed on or before September 6, 2013. Parties unable to file electronically may mail or deliver their comments to the Hon. Jeffrey C. Cohen, Acting Secretary to the New York State Public Service Commission, Three Empire State Plaza, Albany, New York, 12223-1350. All comments submitted to the Secretary will be posted on the Commission's Web site and become part of the official case record.

DPS Staff will host a technical conference on this proposal on August 1, 2013. The technical conference will be held in the 3d Floor Hearing Room located at the Commission's offices at Three Empire State Plaza, Albany, New York 12223-1350. The technical conference will commence at 10:30 A.M.

The agenda for the technical conference will include the following:

- 10:30 AM – Introductions and Summary
- 10:45 AM - Public Policy Requirement
- 11:15 AM - Cost Allocation
- 12:15 – Lunch - On Your Own
- 1:15 PM - Cost Recovery
- 1:45 PM – Risk Mitigation
- 2:30 PM – Adjournment

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[2] See, How to Register with DMM, http://www.dps.ny.gov/e-file/registration.html

Interested parties are encouraged to submit their questions by email in advance of the conference to the following mailbox address: 12-T-0502@dps.ny.gov.

(SIGNED) JEFFREY C. COHEN
Acting Secretary

Attachment

Energy Highway AC Transmission Initiative
Straw Proposal
Case 12-T-0502

Cost Allocation, Cost Recovery & Risk Mitigation

This proceeding was instituted in November 2012 in order to examine AC transmission solutions to congestion problems on portions of the New York State transmission system, specifically the UPNY/SENY and Central East transmission interfaces.[1] On April 22, 2013, the Commission outlined additional steps that will be required over the next several months to pursue the objectives set forth in the November order. The Commission directed staff to issue a straw proposal proposing methods for allocating project costs among ratepayers, addressing the basis for cost recovery, proposing appropriate mechanisms for cost recovery, and mechanisms for allocating risk between developers and ratepayers.[2]

Currently procedures exist under the NYISO's federal tariffs for the allocation and recovery of the costs of certain kinds of transmission projects. However, to address the possibility that the NYISO process may not be available to these projects, or to all types of project sponsors, Staff has undertaken to develop an alternative cost recovery mechanism and cost allocation methodology. Current mechanisms for cost recovery are not designed to compensate non-incumbent developers who do not have designated customers from whom to collect their costs. Staff also recognizes that the benefits of a project or portfolio of projects may not align with current rate structures for cost recovery. This straw proposal is intended to establish mechanisms with input from all parties to 1) allocate risks between developers and ratepayers, 2) allocate the costs of the preferred solutions among utilities, and 3) recover costs from the utility's customers. The chosen methodologies established through this proceeding will provide cost recovery for the projects approved through the Article VII proceeding that best meet the intended objectives.

Staff invites comments on all aspects of the following proposals with the goals of establishing the pursuit of the AC transmission upgrades as a public policy and proposing consensus mechanisms to the Commission for adoption in this proceeding.

[1] Case 12-T-0502, Order Instituting Proceeding (issued November 30, 2012) at 1-2. Specifically, the Commission identified a need for an additional 1,000 MW of transmission capacity in this corridor.

[2] Case 12-T-0502, Order Establishing Procedures For Joint Review Under Article VII of the Public Service law and Approving Rule Changes (Issued April 22, 2013), Ordering Clause 2.

Adequacy of Facilities

The New York State transmission system serves the public by providing safe, reliable and adequate electric energy at just and reasonable rates to all customers in the State. The alternating current (AC) electric transmission corridor that traverses the Mohawk Valley Region, the Capital Region, and the Lower Hudson Valley has been identified as a source of persistent congestion, which results in ratepayer costs that would be avoided if the system were more robust. This corridor is described in the Commission's November 30, 2012 order initiating this proceeding.

For the 5 year period from 2006 through 2010, the congestion across Central-East and down through Pleasant Valley accounted for approximately 72% of the total congestion on the entire system, for a total of $4,827 M in unhedged congestion costs. The Congestion Assessment and Resource Integration Studies (CARIS) performed by the New York Independent System Operator, Inc. (NYISO) with the support of New York's utilities documented historic congestion costs and estimated going-forward congestion costs in this part of the transmission system:

Table 5-2: Historic Demand$ Congestion by Constrained Paths 2006-2010 (nominal $M)[3]

Constrained Path *	2006	2007	2008	2009	2010	Total
CENTRAL EAST	195	572	1,199	435	491	**2,892**
LEEDS_PLSNTVLY 345	452	435	667	149	232	**1,935**
DUNWOODIE_SHORRD_345	492	260	187	118	155	**1,212**
GREENWOOD LINES	119	90	113	87	132	**541**
WEST CENTRAL-OP	2	51	55	1	0	**109**
ASTORIAW138_HG5_138	1	2	1	0	0	**5**
GOTHLS S_ GOWANUS_ 345	0	0	0	0	0	**1**

Looking forward, the same areas of the system are expected to continue to be the top congested elements.

Table 5-5: Projection of Future Demand$ Congestion 2011-2020 by Constrained Path (nominal $M)[4]

Nominal Value ($M) *	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
CENTRAL EAST	268	226	229	209	212	243	257	295	318	329	**2,584**
LEEDS_PLSNTVLY 345	228	199	206	187	205	231	250	307	346	377	**2,535**
DUNWOODIE_SHORRD_345	41	46	49	54	57	60	65	69	73	80	**595**
GREENWOOD LINES	10	10	11	12	12	12	13	15	17	19	**131**
GOTHLS S_ GOWANUSS_ 345	5	4	4	4	5	5	5	6	7	8	**52**

* The absolute value of congestion is reported.

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3 NYISO 2011 CARIS Study.

4 2011 NYISO CARIS Study.

Congestion across the Central-East and UPNY-SENY interfaces has also been confirmed in the NYISO's Wind Study and in the transmission owners' New York State Transmission Assessment and Reliability Study (STARS) report.

In addition to these analyses, several national studies have also identified the Central-East/ Hudson Valley corridor as a priority for congestion relief. Most recently in a study performed by the Eastern Interconnection Planning Council Collaborative (EIPC), this corridor was identified for upgrades. The EIPC modeled transmission build-outs for three very different future energy policy scenarios: 1) business as usual; 2) a nationally implemented constrained carbon policy; and 3) a regionally implemented renewables portfolio standard program. Under all three future scenarios, the Hudson Valley corridor was identified as requiring upgrades.

The US Department of Energy (DOE) performed three nation-wide congestion studies in 2006, 2009, and 2012.[5] In the 2006 study, the same corridor was identified as part of the Atlantic Critical Congestion Area. This conclusion was reaffirmed in the 2009 study. Draft materials for the DOE 2012 report indicate that DOE continues to consider the Hudson Valley transmission corridor as a congested area of concern. In addition, studies performed by and commissioned by DOE labs such as their Eastern Wind Integration and Transmission Study and research studies at Iowa State University have identified this area of the New York system as congested.

This congestion has other consequences for New York customers. In particular, the constrained system is less resilient than a more robust system would be, raising the risk that a transmission issue will impact service to load under severe conditions such as the State experienced in Super Storm Sandy. A more flexible system would also facilitate a wider variety of generation dispatches, thereby allowing the lowest-cost energy to flow under varied contingency situations. The lack of adequate redundancy in the system also makes the rebuilding of aging infrastructure more difficult and costly.

The Public Service Law establishes as public policy that the electric corporations owning, operating, or managing transmission facilities must provide safe and adequate service and that the rates for the service provided must be just and reasonable. The Commission may require utilities to implement improvements to their systems that will best promote the public interest by addressing the persistence and costs of the identified congestion. The Commission may also provide for the appropriate cost allocation and cost recovery associated with such improvements. The conditions the Commission has identified in this proceeding justify requiring and funding transmission system upgrades.

[5] The 2012 study has been released as a draft.

FERC Order 1000

The focus of the proposed rule in this straw proposal is the establishment of a State mechanism for cost recovery and cost allocation that will be available to successful project sponsors. An alternative mechanism for cost recovery may be available pursuant to the NYISO tariff and FERC Order 1000 for transmission projects that meet a Public Policy Requirement, once the tariff becomes effective. Some developers have requested that this option be preserved within the AC Transmission proceeding. Certain Commission-approved determinations are prerequisites to cost recovery under the NYISO's proposed rules

Staff proposes that the Commission find that the Public Service Law requires action to relieve the system congestion identified in Case 12-T-0502, for all of the reasons discussed above, and that this obligation qualifies as a Public Policy Requirement within the meaning of FERC's Order 1000. Staff further proposes that the Commission find the Public Policy Requirement drives a need for transmission solutions.

COST ALLOCATION

Costs will be allocated to the beneficiaries of the upgrades.

The costs of improving and extending this part of the transmission system will be allocated to the ratepayers who are the beneficiaries of the upgrades. While congestion relief is the primary objective, the Commission's order instituting this proceeding and the Energy Highway Blueprint identified a number of additional benefits. Some of these are readily quantifiable and some are not. They are:

- Enhanced system reliability through increased:
  - Resilience: The more paths that exist on the transmission system the lower the likelihood that a transmission issue will impact service to load.
  - Flexible operation: Operators have more options in daily operations. A wider variety of generation dispatches can be accommodated on the system allowing the lowest cost energy to flow even under varied contingency situations.
- Allows easier entry/exit of new generation: When a generator wants to retire, a more robust the transmission system leads to a lower likelihood of having to enter into a reliability must-run contract, and there are fewer upgrades required when new generation interconnect.
- Allows rebuilding of aging infrastructure at a lower cost: The rebuilding of circuits on a congested path poses complex construction challenges. Where there are insufficient redundant paths to permit taking a line out of service, the options for demolition and construction are costly. Besides increased construction costs,

there are also increased congestion costs as operators may need to rely on more expensive downstate generation more often.

- Encourages upstate development of generation where siting and extension of gas lines is easier and can be implemented at a lower cost; basically substituting upstate generation and transmission for new generation in the NYC area.
- Environmental benefits through utilization of more efficient generation reduces air emissions, particularly NOx, SOx and CO2: new transmission will allow the construction of new renewable resources and help to increase access to hydro resources in Quebec.
- Economic Development
  - Promotes job growth and overall economic activity increases: increased construction and maintenance jobs and the associated economic activity; maintains and increases jobs at generation plants.
  - Increases revenues to upstate generators including wind: with decreased congestion, new generation can be sited upstate plus existing generation becomes unbottled allowing more energy sales to the downstate region.
  - Augments and strengthens property tax base: We have seen upstate generators retiring due to low revenues from low dispatch levels. Providing access to a larger market for their energy will help to maintain and increase generation which in turn provides jobs.

All of these benefits will be reflected in determining the beneficiaries of projects in this proceeding.

Proposed Cost Allocation Methodology

The benefits of reducing the identified congestion do not flow equally to all ratepayers. The congestion relief savings and reduced environmental impacts are likely to accrue mainly to customers in the southeastern portion of the state. There are generic statewide benefits from enabling reconstruction of aging infrastructure, but even in this instance most of the savings involve lower dispatch costs which accrue to downstate loads. On the other hand, the benefits from increased jobs, tax base, and development are likely to accrue to upstate areas.

Staff proposes that the Commission employ two established NYISO methodologies to allocate the costs of the projects that are approved as a result of the Commission's AC transmission initiative. Fifty percent of project costs will be allocated to the economic beneficiaries of reduced congestion consistent with the methodology embodied in the

NYISO CARIS process.[6] The other fifty percent of the costs will be allocated to all customers on a load-ratio share. Given that the loads in the southeastern portion of the state receive most of the economic benefit of the reduced congestion, the majority of the costs will be allocated to those loads. For the load-ratio share portion of the calculation, the majority of load in the state is in the southeastern portion of the state, so that while some costs will be allocated upstate, the bulk of the costs will be allocated downstate.

Example – To aid in calculating the load-ratio share, below is a table from the NYISO's 2013 Load and Capacity Data Report.

Forecast of Annual Energy by Zone - GWh

Year	A	B	C	D	E	F	G	H	I	J	K	NYCA
2013	15,922	10,165	16,281	6,712	8,093	11,807	10,146	2,949	6,141	54,252	22,753	165,221
	9.6%	6.2%	9.9%	4.1%	4.9%	7.1%	6.1%	1.8%	3.7%	32.8%	13.8%	100%
				41.8%					58.2%			

For simplicity of illustration, assume that zones G-K are the beneficiaries of reduced congestion. Therefore half of the total project costs would be assigned to zones G-K and none would be allocated to zones A-F. On a load-ratio share, the remaining half of the costs would be allocated 41.8% to zones A-F and G-K would accrue 58.2%. Putting the two together, zones A-F would then be absorbing 20.9% and zones G-K would be allocated 79.1% of total costs.

While this calculation is performed at a high level, Staff's proposal is that the load-ratio share be allocated based on individual utility load and that the economic beneficiaries be determined down to the sub-zone level[7] consistent with the CARIS model. The degree of NYPA and LIPA participation will need to be addressed.

Staff proposes that Transmission Congestion Contracts (TCCs) and any other market revenues from the project would be allocated to the responsible utilities as determined in accordance with the cost allocation methodology ultimately adopted. Revenues from the TCCs would go to ratepayers (beneficiaries) to help offset their payments for the transmission solutions.

COST RECOVERY

Current mechanisms for cost recovery are not designed to compensate non-incumbent developers who do not have designated customers from whom to collect their costs. Staff also recognizes that the benefits of a project or portfolio of projects may not align

[6] See Appendix A for an excerpt from the NYISO FERC OATT Tariff Attachment Y that addresses economic cost allocation.

[7] See Appendix B for an illustration of the LBMP zone and sub-zone definitions.

with current rate structures for cost recovery. This straw proposal is intended to establish mechanisms to recover costs from the utility customers.

Proposed Cost Recovery Mechanism

New York Transmission Owners (TOs).

For Incumbent transmission projects, Staff recommends that the Commission provide cost recovery through rate base treatment of the transmission plant in the rate case of the Transmission Owner building the project. Through that process, the Transmission Owner would place the plant in service and then earn a return on and of its investment. Under this methodology, the revenue requirement associated with the plant will be offset by payments from other responsible utilities as determined in accordance with the cost allocation methodology ultimately adopted. The charge to ratepayers will be determined in the same manner as other transmission capital and operating costs. Costs will be allocated among service classes based on the respective contribution of each service class to the coincident peak demand. Once allocated, those costs will be recovered through class-specific surcharges rather than in base rates. The use of a surcharge allows immediate recovery of costs rather than waiting for base rates to be reset during a major rate proceeding.

Each class-specific surcharge will recover allocated costs via volumetric (kWh) charges from non-demand metered classes and demand (kW) charges from classes with demand meters. Further, costs shall be recovered from standby customers via the daily as-used demand charges, consistent with the Commission's Standby Rate Order, which allows the cost of facilities, such as transmission facilities, to be recovered when the customer uses the electric delivery system.

The payments from other responsible utilities would be equal to the revenue requirement associated with their allocation of the cost of the selected project. If a responsible utility is allocated 10% of the cost of the transmission solution, its payment to the Transmission Owner would be the equivalent revenue requirement associated with 10% of the project's costs, using the same ratemaking components (i.e., cost of capital, return, depreciation, etc.) as the Transmission Owner (the Transmission Owner would rate base the project and treat it like all of its other transmission plant).   For example, assume the selected project costs $500 million and a responsible utility is allocated 10% of the cost of the project ($50 million), the revenue requirement associated with the responsible utility's cost share is then determined using the Transmission Owner's cost of capital, return, and depreciation (for this example, assume 15%).   In this example, the responsible utility's payment to the Transmission Owner would be $7.5 million ($50 x 15% = $7.5). Each year, the payment would be recalculated using current costs and plant balances. In this manner, the other responsible utilities would offset the Transmission Owner's revenue requirement in proportion to their cost responsibility. Payments would be made until the original book cost of the project is fully depreciated and would not include any capitalized improvements made to the transmission solution.

Independent Transmission Developers.

Staff proposes that non-incumbent transmission projects could recover their costs via either contracts or tariffs. Staff seeks comments on which of these options would be preferred; Staff also welcomes other suggested approaches.

Under the contract method, the non-incumbent project developer could enter into contracts with each responsible Transmission Owner. Under this methodology, the term of the contracts would match the average service life of the transmission plant (i.e., 40-50 years).

Under the tariff method, the non-incumbent project developer, being a regulated electric corporation, would have a Commission-approved tariff schedule. Under the terms of the tariff, the non-incumbent project developer would charge the responsible Transmission Owners an annual amount in accordance with the results of the cost allocation for the relevant loads. The tariff need not have a set term limit, as future maintenance cost and capital improvements to extend the life of the project would need to be recovered. Alternatively, a sunset provision could be enacted so that the term of the tariff would match the anticipated average service life of the transmission plant.

Under the contract and the sunset tariff approach, questions arise as to the future ownership, property rights, and operation of the transmission project once the contract or tariff expires. Comments are also sought addressing these issues.

Approaches to this issue are also under consideration in another proceeding, Case 12-E-0503.

RISK ALLOCATION

Staff proposes that the Commission require developers (TOs and independents) to price their projects in accordance with a method for mitigating the risk of cost overruns. While there are several existing models from which to draw, each allocates a different level of risk sharing between ratepayers and developers. Staff has identified several models that could be applied to the AC Transmission proceeding. Comments are requested as to the suitability of each model for this proceeding, the pros and cons of application of each model, which model may be preferred along with justification, and when in the process would be the appropriate time for submittal of firm bids.

Risk Allocation Models:

I. Traditional Regulation

The traditional regulation model is intended to mirror the regulatory environment currently afforded utility infrastructure investment. Under this model, qualified developers would be required to submit bids for the construction, operation and maintenance of the transmission facility. The developers would become subject to PSC jurisdiction as utility corporations and be allowed recovery of all prudently incurred costs.

The traditional regulation model allocates the risk of prudently incurred cost overruns solely on customers with responsibility for any imprudently incurred costs falling on the developer.

This model entails a high level of uncertainty as to the ultimate costs for which ratepayers will be responsible. In addition, because this model allows for recovery of all prudently incurred costs, there is little incentive for the developer to control costs, which could lead to cost overruns.

The traditional regulation model minimizes the risk borne by the developer, which should maximize the number of developers that participate in this process and will likely yield an acceptable winning project. Also, there is a high likelihood that a developer with access to capital will follow through with the project even if faced with unexpected major cost adders.

II. Partial pass-through

This is a variant of traditional regulation, in which cost over-runs or under-runs are shared between ratepayers and shareholders (e.g. 80%/20%), similar to a partial pass-through fuel adjustment clause. Thus if actual costs came in above the bid, the developer would bear a share (20%) of the over-run; and if actual costs came in below the bid, the developer would retain a share (20%) of the savings. The idea is to provide incentives for cost control while limiting the risk premium required by developers.

Under the partial pass-through model, bids are less likely to be understated than under traditional regulation, so reducing reliance on independent cost estimates by the entity that does the comparison. Also, cost control is reasonably good, since the developer retains an incentive to minimize costs; however, customers bear a significant share of the risks of cost over-runs that do occur. Developers may include a risk premium in their bids, but the premium should be reduced by the risk-sharing feature.

III. Firm construction bid with traditional regulation on operation and return

This model is similar to the traditional regulation model in that qualified developers would submit bids for the construction, operation and maintenance of the transmission facility. A successful developer would become subject to PSC jurisdiction as a utility corporation. However, the developer would only be allowed to include in rate base the fixed amount of its bid for construction of the project. Ongoing operation and maintenance costs would also be fixed for a period of years (e.g., 5, 10, etc.). Again, the cost recovery of the project would be created through rate proceedings, filed by the developer with the PSC, in which all costs (i.e., construction, operation, maintenance, capital, etc.) would be subject to Staff review and Commission determination.

The firm construction bid model allocates the risk of prudently incurred cost overruns solely on the developer. However, customers are at risk for inflated construction bids and potential O&M increases.

A disadvantage of employing this model is that firm bids would be required as part of the comparative evaluation process. This could result in bid prices that are inflated and not representative of the likely final cost to developers. Because the developers will bear large risks, it is likely they will seek corresponding risk premiums, thereby increasing costs to ratepayers. Also, because of the added risk, there is the possibility of yielding low participation by developers in the process. In addition, a winning developer could abandon its project if faced with unexpected major cost adders (e.g., rerouting or undergrounding) or may take actions to reduce actual costs during construction that result in higher recoverable O&M costs during operation of the facility.

There are advantages to this model: comparing projects is relatively simple, and there is an incentive among all developers to maximize the accuracy of their estimates. Moreover, because a developer will only be allowed to include its bid amount in rate base, there is a strong incentive on the developer to maximize its control on construction costs.

IV. Firm construction bid within tolerance band with traditional regulation on operation and return

A variant to the firm construction bid is a model that would specify a tolerance band (e.g. +/- 20% of bid) within which the developer would bear all construction cost risks; above the tolerance band, customers would bear incremental cost overruns, and below the tolerance band, customers would retain incremental cost savings.

This model allocates the risk of cost overruns within the tolerance band on the developer. Customers will bear the risk of cost overruns over the specified tolerance band. Other risks that customers will bear are the potential for increased construction bids and the potential for future O&M increases, but risks may be lessened due to the cost overrun and cost saving requirements placed by the tolerance band.

Under this model, the sharing of cost overruns creates an incentive for the developer to control costs on behalf of both parties while creating a protection for the developer for unforeseen circumstances. Developer bids are likely to be more accurate than if the traditional model was used and there would likely be increased developer bid participation than under a fully capped model.

However, there may be a lack of participation from some developers because of the risks associated with the tolerance band or there may be increased bids.

V. Firm (indexed) construction bid with variable components for high risk, low control items

Another variant to the firm construction bid is a model that would require the developer to commit to a fixed price with some cost items deemed to be largely beyond its control tied to an index or benchmark, which can be recovered/returned if the benchmark goes above/below an agreed to target. For example, the cost of steel or concrete can be tied to a specific price on a futures market, or capital costs can be tied to an interest benchmark. Similarly, the price for operating & maintenance could be subject to an inflation/productivity adjustment.

Further, adjustments could be allowed for government imposed change orders. Under this model, customers would still be at risk for significant cost overruns, but only for those items that are deemed to be largely beyond the developer's control.

Under this model, bids should be more firm than under the traditional regulation model and the risk premiums built into the bids should be smaller than under the firm bid models. This model may be more attractive to developers than the firm bid model while still providing incentives to control costs.

There would be a significant amount of time necessary early on in the process to determine which cost components are largely beyond the developer's control and should be made variable and to determine the proper benchmark to target. This model would require follow-up filings, reviews, and audits to determine the variable costs trued-up.

VI. Fixed price contract

Under the fixed price contract model, developers would submit bids for construction, operation, and maintenance of the AC transmission facility. The bid would be a fixed annual contract price for a period of years (e.g., 40 or 50). There would be no rate proceedings and costs would not be subject to Staff review or Commission determination. Under this model, the developer is at risk for all costs in excess of the bid price and for any future costs increases.

Under the fixed price contact model, bids would be binding and thus, more firm than any previously described model. However, the risk premium built into the bids could be significant and may be so inflated that the bids are not representative of the likely final cost to developers.

Appendix A

Excerpt from NYISO OATT Attachment Y

31.4.3.4 Cost Allocation for Eligible Projects

As noted in Section 31.4.3.2 of this Attachment Y, the cost of a RETP will be allocated to those entities that would economically benefit from implementation of the proposed project.

31.4.3.4.1 The ISO will identify the beneficiaries of the proposed project over a ten-year time period commencing with the proposed commercial operation date for the project. The ISO, in conjunction with the ESPWG, will develop methodologies for extending the most recently completed CARIS database as necessary for this purpose.

31.4.3.4.2 The ISO will identify beneficiaries of a proposed project as follows:

31.4.3.4.2.1 The ISO will measure the present value of the annual zonal LBMP load savings for all Load Zones which would have a load savings, net of reductions in TCC revenues, and net of reductions from bilateral contracts (based on available information provided by Load Serving Entities to the ISO as set forth in subsection 31.4.3.4.2.5 below) as a result of the implementation of the proposed project. For purposes of this calculation, the present value of the load savings will be equal to the sum of the present value of the Load Zone's load savings for each year over the ten-year period commencing with the project's commercial operation date. The load savings for a Load Zone will be equal to the difference between the zonal LBMP load cost without the project and the LBMP load cost with the project, net of reductions in TCC revenues and net of reductions from bilateral contracts.

31.4.3.4.2.2 The beneficiaries will be those Load Zones that experience net benefits measured over the first ten years from the proposed commercial operation date for the project. If the sum of the zonal benefits for those Load Zones with load savings is greater than the revenue requirements for the project (both load savings and revenue requirements measured in present value over the first ten years from the commercial operation date of the project), the ISO will proceed with the development of the zonal cost allocation information to inform the beneficiary voting process.

31.4.3.4.2.3 Reductions in TCC revenues will reflect the forecasted impact of the project on TCC auction revenues and day-ahead residual congestion rents allocated to load in each zone, not including the congestion rents that accrue to any Incremental TCCs that may be made feasible as a result of this project. This impact will include forecasts of: (1) the total impact of that project on the Transmission Service Charge offset applicable to loads in each zone (which may vary for loads in a given zone that are in different Transmission Districts); (2) the total impact of that project on the NYPA Transmission Adjustment Charge offset applicable to loads in that zone; and (3) the total impact of that project on payments made to LSEs serving load in that zone that hold Grandfathered Rights or Grandfathered TCCs, to the extent that these have not been taken into account in the calculation of item (1) above. These forecasts shall be performed using the procedure described in Appendix B to this Attachment Y.

31.4.3.4.2.4 Estimated TCC revenues from any Incremental TCCs created by a proposed RETP over the ten-year period commencing with the project's commercial operation date will be added to the Net Load Savings used for the cost allocation and beneficiary determination.

31.4.3.4.2.5 The ISO will solicit bilateral contract information from all Load Serving Entities, which will provide the ISO with bilateral energy contract data for modeling contracts that do not receive benefits, in whole or in part, from LBMP reductions, and for which the time period covered by the contract is within the ten-year period beginning with the commercial operation date of the project. Bilateral contract payment information that is not provided to the ISO will not be included in the calculation of the present value of the annual zonal LBMP savings in section 31.4.3.4.2.1 above.

31.4.3.4.2.5.1 All bilateral contract information submitted to the ISO must identify the source of the contract information, including citations to any public documents including but not limited to annual reports or regulatory filings

31.4.3.4.2.5.2 All non-public bilateral contract information will be protected in accordance with the ISO's Code of Conduct, as set forth in Section 12.4

of Attachment F of the ISO OATT, and Article 6 of the ISO Services Tariff.

31.4.3.4.2.5.3 All bilateral contract information and information on LSE-owned generation submitted to the ISO must include the following information:

(1) Contract quantities on an annual basis:

(a) For non-generator specific contracts, the Energy (in MWh) contracted to serve each Zone for each year.

(b) For generator specific contracts or LSE-owned generation, the name of the generator(s) and the MW or percentage output contracted or self-owned for use by Load in each Zone for each year.

(2) For all Load Serving Entities serving Load in more than one Load Zone, the quantity (in MWh or percentage) of bilateral contract Energy to be applied to each Zone, by year over the term of the contract.

(3) Start and end dates of the contract.

(4) Terms in sufficient detail to determine that either pricing is not indexed to LBMP, or, if pricing is indexed to LBMP, the manner in which prices are connected to LBMP.

(5) Identify any changes in the pricing methodology on an annual basis over the term of the contract.

31.4.3.4.2.5.4 Bilateral contract and LSE-owned generation information will be used to calculate the adjusted LBMP savings for each Load Zone as follows:

$AdjLBMPS_{y,z}$, the adjusted LBMP savings for each Load Zone z in each year y, shall be calculated using the following equation:

$$AdjLBMPS_{y,z} = \max\left[0, TL_{y,z} - \sum_{b \in B_{y,z}} \left(BCL_{b,y,z} \cdot \left(1 - Ind_{b,y,z}\right)\right) - SG_{y,z}\right] \cdot \left(LBMP1_{y,z} - LBMP2_{y,z}\right),$$

Where:

$TL_{y,z}$ is the total annual amount of Energy forecasted to be consumed by Load in year y in Load Zone z;

$B_{y,z}$ is the set of blocks of Energy to serve Load in Load Zone z in year y that are sold under bilateral contracts for which information has been provided to the ISO that meets the requirements set forth elsewhere in this Section 31.4.3.4.2.5

$BCL_{b,y,z}$ is the total annual amount of Energy sold into Load Zone z in year y under bilateral contract block b;

$Ind_{b,y,z}$ is the ratio of (1) the increase in the amount paid by the purchaser of Energy, under bilateral contract block b, as a result of an increase in the LBMP in Load Zone z in year y to (2) the increase in the amount that a purchaser of that amount of Energy would pay if the purchaser paid the LBMP for that Load Zone in that year for all of that Energy (this ratio shall be zero for any bilateral contract block of Energy that is sold at a fixed price or for which the cost of Energy purchased under that contract otherwise insensitive to the LBMP in Load Zone z in year y);

$SG_{y,z}$ is the total annual amount of Energy in Load Zone z that is forecasted to be served by LSE-owned generation in that Zone in year y;

LBMP1y,z is the forecasted *annual load-weighted average LBMP* for Load Zone z in year y, calculated under the assumption that the project is not in place; and

$LBMP2_{y,z}$ is the forecasted annual load-weighted average LBMP for Load Zone *z* in year *y*, calculated under the assumption that the project is in place.

31.4.3.4.2.6. NZS_z, the Net Zonal Savings for each Load Zone *z* resulting from a given project, shall be calculated using the following equation:

$$NZS_z = \max\left[0, \sum_{y=PS}^{PS+9}\left(\left(AdjLBMPS_{y,z} - TCCRevImpact_{y,z}\right)\cdot DF_y\right)\right],$$

Where:

PS is the year in which the project is expected to enter commercial operation;

$AdjLBMPS_{y,z}$ is as calculated in Section 31.4.3.4.2.5;

$TCCRevImpact_{y,z}$ is the forecasted impact of TCC revenues allocated to Load Zone *z* in year *y*, calculated using the procedure described in Appendix B in Section 31.6 of this Attachment Y; and

DF_y is the discount factor applied to cash flows in year *y* to determine the present value of that cash flow in year *PS*.

31.4.3.4.3 Load Zones not benefiting from a proposed RETP will not be allocated any of the costs of the project under this Attachment Y. There will be no “make whole” payments to non-beneficiaries.

31.4.3.4.4 Costs of a project will be allocated to beneficiaries as follows:

31.4.3.4.4.1 The ISO will allocate the cost of the RETP based on the zonal share of total savings to the Load Zones determined pursuant to Section 31.4.3.4.2 to be beneficiaries of the proposed project. Total savings will be equal to the sum of load savings for each Load Zone that experiences net benefits pursuant to Section 31.4.3.4.2. A Load Zone's cost allocation will be equal to the present value of the following calculation:

$$\text{Zonal Cost Allocation} = \text{Project Cost} \times \left(\frac{(\text{Zonal Benefits})}{\text{Total Zonal Benefits for zones with positive net benefits}} \right)$$

31.4.3.4.4.2 Zonal cost allocation calculations for a RETP will be performed prior to the commencement of the ten-year period that begins with the project's commercial operation date, and will not be adjusted during that ten-year period.

31.4.3.4.4.3 Within zones, costs will be allocated to LSEs based on MWhs calculated for each LSE for each zone using data from the most recent available 12 month period. Allocations to an LSE will be calculated in accordance with the following formula:

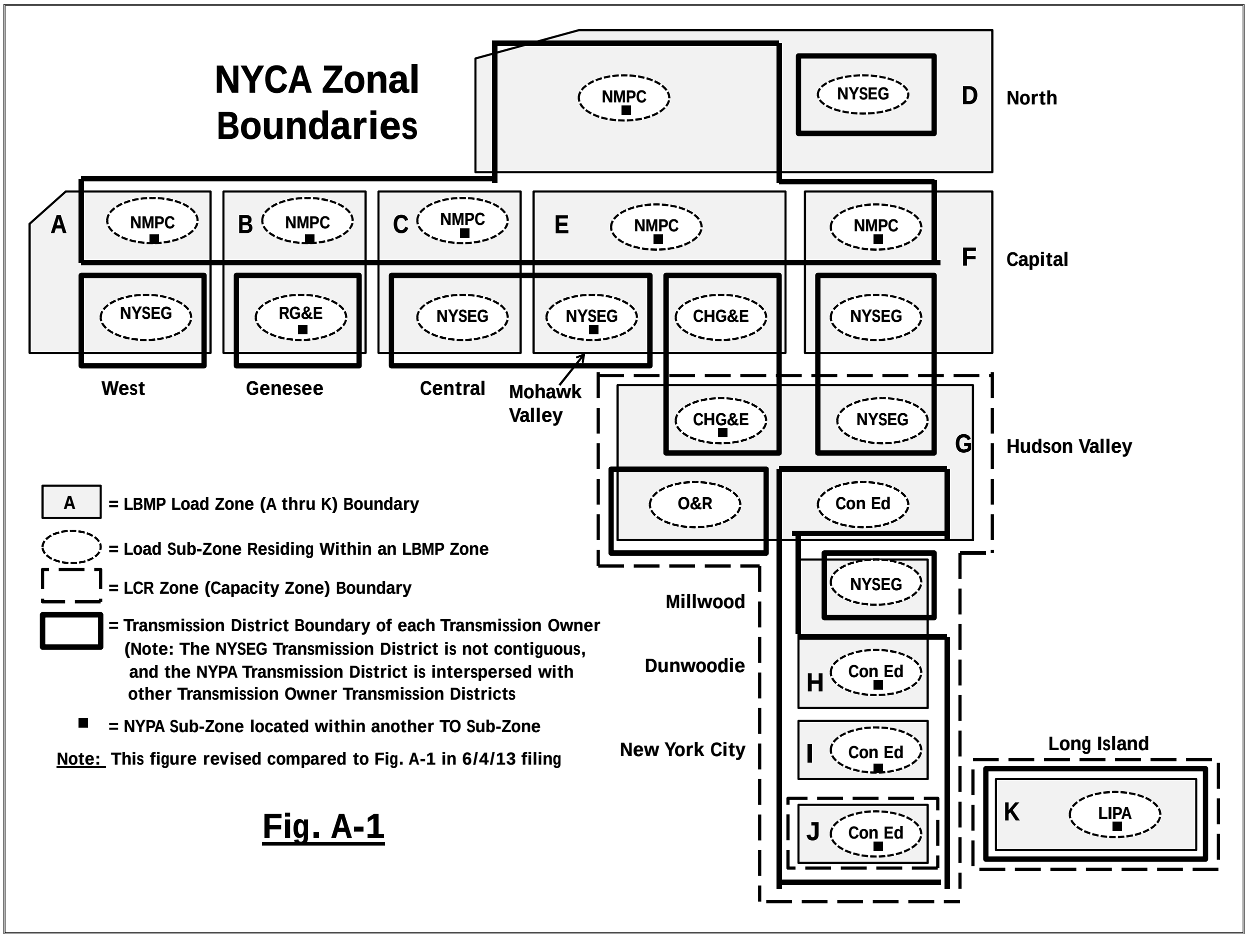
$$\text{LSE Intrazonal Cost Allocation} = \text{Zonal Cost Allocation} \times \left(\frac{\text{LSE Zonal MWh}}{\text{Total Zonal MWh}} \right)$$

31.4.3.4.5 Project costs allocated under this Section 31.4.3.4 will be determined as follows:

31.4.3.4.5.1 The project cost allocated under this Section 31.4.3.4 will be based on the total project revenue requirement, as supplied by the Developer of the project, for the first ten years of project operation. The total project revenue requirement will be determined in accordance with the formula rate on file at the Commission. If there is no formula rate on file at the Commission, then the Developer shall provide to the ISO the project-specific parameters to be used to calculate the total project revenue requirement.

Appendix B

Transmission Districts, LBMP Load Zones and Load Sub-Zones in New York



Source: New York State Independent System Operator

Transmission Districts delineate Transmission Owner (TO) service territories. A Transmission District or "TD" is the geographic area served by the Investor-Owned Transmission Owners and LIPA, as well as the customers directly interconnected with the transmission facilities of the Power Authority of the State of New York. A Transmission District can be comprised of one or more LBMP Load Zones and one or more Load Sub-Zones.

LBMP Load Zones delineate areas with generally similar energy prices that may be separated from other areas (other LBMP Load Zones) that have different energy prices due to congestion. An LBMP Load Zone or "Load Zone" is one (1) of eleven (11) geographical areas located within the New York Control Area (NYCA) that is bounded by one (1) or more of the fourteen (14) New York State Transmission Interfaces. An LBMP Load Zone can lie within one Transmission District or can straddle two or more Transmission Districts.

Load Sub-Zones delineate portions of TO service territories for billing purposes. A Load Sub-Zone or "Sub-Zone" is a whole or portion of a TO's Transmission District that lies within one LBMP Load Zone, and which contains all of the load in that LBMP load zone served by that TO. A Load Sub-Zone must lie completely within one LBMP Load Zone and one Transmission District. Load Sub-Zones are separated from other Load Sub-Zones with sufficient tie-line metering to allow each Load Sub-Zone to be billed individually for energy withdrawals. Multiple Load Serving Entities (LSEs) may be located within each Load Sub-Zone. Currently, twenty-two Load Sub-Zones (excluding NYPA Sub-Zones as discussed below) exist within the NYCA.

The current Sub-Zone composition of each TO's Transmission District is as follows …

	TD Composition	
	No. of Load **Sub-Zones** that **Share Portions** of LBMP Load Zones	No. of Load **Sub-Zones** that **Constitute an Entire** LBMP Load Zones
Central Hudson	2	0
Con Ed	2	2
LIPA	0	1
NYPA	10*	0
NYSEG	7	0
NMPC/National Grid	6	0
O&R	1	0
RG&E	1	0
* NYPA Sub-Zones all lie within other TO Sub-Zones; so for the purposes of cost allocation, they will be treated as an integral part of the larger Sub-Zones		