ComEd Ex. 1.0

STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

ROCK ISLAND CLEAN LINE LLC	:	
	:	
Petition for an Order granting Rock Island Clean Line LLC a Certificate of Public Convenience and Necessity pursuant to Section 8-406 of the Public Utilities Act as a Transmission Public Utility and to construct, operate and maintain an electric transmission line and authorizing and directing Rock Island pursuant to Section 8-503 of the Public Utilities Act to construct an electric transmission line.	:	No. 12-0560

Direct Testimony of

STEVEN T. NAUMANN, P.E.

Vice President
Transmission and NERC Policy
Exelon Business Services Company

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I. INTRODUCTION

A. Witness Identification

Q. Please state your name and business address.

A. Steven T. Naumann. My business address is 10 South Dearborn Street, 47th Floor, Chicago, Illinois 60603.

Q. By whom are you employed and in what capacity?

A. I am the Vice President, Transmission and NERC Policy of Exelon Business Services Company ("EBSC"). EBSC is the services company affiliated with Commonwealth Edison Company ("ComEd") and other Exelon Corporation operating utilities, and many EBSC officers and employees provide services to Exelon utilities. For example, I provide advice and guidance to Exelon's transmission-owning utilities, such as ComEd, on policy and regulatory questions concerning transmission system planning, design, operation, and rates, terms, and conditions of service.

B. Summary of Testimony

Q. What, in sum, has ComEd concluded about the requests of Rock Island Clean Line LLC ("RI") at issue in this Docket?

A. RI asks the ICC[1] to (1) issue a Certificate of Public Convenience and Necessity ("CPCN") authorizing RI to operate under Illinois law as a transmission-only public utility; (2) issue a second CPCN authorizing RI to construct, operate, and maintain within Illinois a major portion of RI's multi-billion dollar transmission project (the "Project"),

[1] I refer to the Illinois Commerce Commission as the "ICC" and the Federal Energy Regulatory Commission as "FERC" to avoid any confusion between the two Commissions.

and (3) order it, under Section 8-503 of the Illinois Public Utilities Act ("PUA"), to build the Project.

For many reasons, the Petition, direct testimony, and data request responses – as revised and supplemented through June 21, 2013 – do not justify issuance of a CPCN at this time. The Project is simply not developed enough for final regulatory evaluation. Moreover, RI's request for an order under Section 8-503 is both premature and inconsistent with RI's own testimony and the conditionality of RI's commitment to build the Project.

Q. **How is your direct testimony organized in relation to these conclusions?**

A. First, in **Section II,** I explain ComEd's recommendations in detail.

In **Section III**, I discuss specific gaps in the Project itself, *i.e.*, important ways in which analysis, planning, and design of the Project remain incomplete and/or are in flux, and the uncertainties and risks that result.

In **Section IV**, I address how these uncertainties affect the costs and benefits of the Project and how they may affect customers. The direct testimony of Ms. Ellen Lapson (ComEd Ex. 2.0) addresses RI's own financial condition and its ability to complete the Project.

Section IV addresses other flaws in RI's submissions, including inaccuracies in claimed reliability and economic benefits.

Finally, in **Section V**, I address RI's request that the ICC rule that the public need requires construction of this line and issue an order directing RI to build the line, despite the fact that RI has not claimed or proved public need in the FERC-jurisdictional regional planning process and despite the fact that RI's own witnesses underscore that this is a "spec"-like project that RI may not even try to build.

C. Background and Qualifications

Q. Please describe your professional and educational background.

A. I have almost forty years of experience in dealing with transmission matters and, in particular, with the ComEd transmission system, the transmission systems now operated by PJM Interconnection L.L.C. ("PJM"), and coordination between PJM and the Midcontinent Independent System Operator, Inc. ("MISO"), formerly known as the Midwest Independent Transmission System Operator, Inc. That experience includes planning, technical analysis, reliability, security, and regulation. I am licensed in Illinois as a Professional Engineer and an attorney, although I do not practice law. I hold a Bachelor of Science degree in Electric Power Engineering, a Master of Engineering degree in Electric Power Engineering, both from Rensselaer Polytechnic Institute in New York, and a Juris Doctor from Chicago-Kent College of Law. My biographical summary, attached as ComEd Exhibit ("Ex.") 1.01, provides more detail on my qualifications, my publications, and my previous testimony.

D. Attachments to Direct Testimony

Q. Are you sponsoring any attachments to your testimony other than ComEd Ex. 1.01?

A. Yes. ComEd Ex. 1.02 is a redacted version of Attachment 1 to RI's response to Data Request ComEd → RI 3.10. The unredacted document was designated as "Confidential" by RI. Counsel for RI provided the redacted version.

II. OVERVIEW OF THE PROJECT AND COMED'S RECOMMENDATIONS

A. The Project and Its Relation to the Transmission System

Q. **Please summarize the Project, as described in RI's Petition and the transmission facilities that it will involve?**

A. The Project is a $2 billion plus set of additions to the transmission system designed to provide a "direct" connection between generators located in or interconnected to northwestern Iowa and load in the Chicago area and, importantly, points east. Its largest single component is a single-circuit ±600kV direct current ("DC") line between these endpoints. As described by RI, the west end of that line will be in O'Brien County, Iowa. The east end of the DC line is proposed to terminate southwest of Chicago.

Because it is a DC line, it has several features of importance. First, to connect with the alternating current transmission grid and allow for voltage transformation an AC-DC converter station ("Converter Station") is required at each end. These are significant and costly "substation-like" installations. As proposed, the converter station at the Iowa end of the DC line would interconnect with the transmission system owned by MidAmerican Energy Company ("MidAmerican"). At the Illinois end the converter station would deliver AC power to the ComEd transmission system. The Petition describes an interconnection that includes several new 345kV AC lines that extend several miles from the Converter Station before connecting to the transmission system at ComEd's Collins substation in Grundy County, Illinois. However, RI has also proposed a different form of interconnection involving cutting existing 345 kV lines and rerouting them through facilities at the Converter Station, which I discuss further below.

Electrically, the DC line behaves in many ways like a more conventional "generator lead" – typically a radial line whose purpose is simply to move power from a generator to an interconnection point where it is injected into the transmission system. In addition, because it is a DC line terminating at either end in converter stations, its flow can be throttled unlike an AC line integrated into the bulk power system. In this way, the operators of the line could limit the power flowing across it to the output of those generators who have contracted with the operators for that service. Essentially, the technology allows the operators to limit the use of the line only to those who have paid the operator to use the line. This "toll gate" like characteristic is key to the "merchant" economic model.

Q. **What is a "merchant" transmission project and how does that differ from a traditional project funded through transmission rates?**

A. A "merchant" transmission project refers to a project where the owner assumes "the full market risk of the cost of constructing the proposed transmission project."[2] Merchant transmission line owners also must pay all the costs of operating and maintaining the merchant transmission line.

A concept developed and defined by FERC, if a merchant project meets all of FERC's conditions, FERC will grant its operators "negotiated rate authority" which means that the owner of the project can charge users of the project whatever rates the customer agrees to pay. It also means that those rates should only be paid by those

[2] *Rock Island Clean Line LLC*, 139 FERC ¶ 61,142 at P 13 (2012) (hereinafter "*Rock Island Clean Line").*

customers (in this case, RI says they hope to secure generators and suppliers) who agree to pay them in exchange for rights to use the project. This differs from normal rate-based transmission facilities that serve all customers, such as those that ComEd has recently built, the cost of which are recovered through cost-based rates analogous to distribution rates.[3] Thus, merchant transmission line owners get to charge whatever rates customers agree to pay but in return they agree not to impose any project risks on customers.

Q. **How does the Project's status as a merchant project affect its participation in the regional planning process typically applicable to transmission projects?**

A. Because the owners assume all financial risk, a merchant project need not demonstrate a public need, operational benefit, or net market efficiency benefit to be approved by PJM and/or MISO. Indeed, it need not even participate in that aspect of the regional planning process.

At the regional level, RI has not claimed or shown that the Project is necessary for reliability, operating efficiency, or market efficiency in the regional planning process conducted by PJM. The ICC should not confuse the Project with projects included in the PJM Regional Transmission Expansion Plan ("RTEP") or with an expansion or "multi-value project" approved under the MISO regional planning process. Those projects have demonstrated a public benefit in a regional planning process. This Project has not. Yet, at the ICC, the Project is being presented as a project that is entitled to a CPCN, which presumes a public need.

[3] As I stated above, the term merchant transmission line is a FERC term of art, and should not be confused with a non-utility transmission developer building a cost of service line which would go into rate base (if in PJM it were approved in the PJM regional plan). While merchant lines are almost exclusively non-utility, a non-utility developer may or could develop a non-merchant transmission project.

Q. **In evaluating a transmission addition such as the Project, are the actual project facilities the only new facilities that are required or that a regulator should consider?**

A. No. The facilities proposed by a developer are often only a subset of what is required to integrate the proposed facilities into the system. Additions to the transmission system, particularly those proposing to "inject" significant quantities of power at one location, often have significant effects on the existing system that require substantial additions and modifications to that system.

In this case, the facilities for which RI seeks a CPCN are far from the complete story. As I will explain later, at this stage of the study process, among the upgrades that PJM has identified as required if the Project is built is a substantial 765 kV line from Illinois well into Indiana.

Q. **Who should bear the cost of these added facilities?**

A. In addition to the cost of developing a project, i.e., the cost of the line, merchant transmission owners must pay all other costs necessary to connect the line to the existing transmission system. This means all the costs of upgrades necessary to reliably interconnect the project and allow the delivery of energy. This is an important protection for customers, and the ICC should ensure that the Project is not built as a "merchant" project outside the planning process, but then turned into a rate-based line, paid for by customers, at a later date.

Q. **How would the Project function as part of the regional transmission system?**

A. The Project's stated purpose is to connect generation in Iowa or further west and deliver the energy into the ComEd system. That is, essentially, how it will function. While the Project will connect on the west end to the MidAmerican system, for all intents and purposes, it is a long generator lead. It should be evaluated on that basis.

Q. **Is it accurate to describe the RI Project as one that, if built, will deliver 100% wind-generated or 100% renewable electricity to Illinois customers or PJM?**

A. I am aware that RI has described the Project, even very recently, as being aimed at "connect[ing] some of the best wind energy resources in the country..." and "delivering clean energy ..."[4] No one knows what generation might ultimately utilize the line, and based on FERC's ruling concerning RI's request for market pricing authority[5] and on statements made by RI in other venues, I believe the answer is no. Any generator could use the line on equal terms, although they may end up negotiating different charges.

Second, in its discussions with PJM concerning the use of the line for reliability studies, RI has argued that PJM should not model the line as delivering 100% wind energy.[6] RI specifically told PJM that PJM should not assume that RI should be modeled as "a wind-sourced injection."[7]

Third, real market uncertainties prevent accurate predictions of what generation, if any, might find use of the line to be economic. At this point, no one can predict if

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[4] Petition, Attachment 11 (RI Landowner Information Packet) Revised, p. 1. Although this document bears that date June 19, 2012, it was served this month and it appears that is should be dated June 19, 2013.

[5] *Rock Island Clean Line* at P 31.

[6] Response to Data Request ComEd → RI 3.26.

[7] ComEd Ex. 1.02. This document in unredacted form was marked "Confidential." Counsel for RI provided the redacted version, to which I refer. It is not Confidential.

renewable generation will contract with RI to transmit energy over the line or whether other generation will want to do so in order to access the PJM market. The market will make that determination.

B. <u>ComEd's Position on the Petition</u>

Q. **What actions does the Petition ask the ICC to take in this Docket?**

A. RI asks the ICC for three things. First, RI asks for a CPCN to operate under Illinois law as a transmission-only public utility. Second, RI seeks a CPCN to construct, operate, and maintain the Project within Illinois. Third, it asks the ICC to order it, under Section 8-503 of the Illinois PUA, to build the Project.

Q. **What action should the ICC take on RI's request for a CPCN to construct, operate, and maintain the Project, given the information currently provided by RI?**

A. A party seeking a CPCN from the ICC should, at a minimum, tell the ICC what must be built, where it will be built, how it will affect reliability, how much it will cost, and how that cost will be recovered. RI, at this time, can establish none of these things with reasonable certainty. The Project simply is not ready for ICC regulatory approval.

The ICC should, therefore, deny the request for a CPCN without prejudice to future resubmission at such a time as (a) the major uncertainties surrounding the Project become resolved, and (b) RI unconditionally commits that the Project will remain a merchant transmission project. Alternatively, RI could ask the ICC to stay this Docket until those conditions are met. But, based on the information filed by RI, and given the important uncertainties and risks to ComEd and Illinois transmission customers, the ICC should not issue a CPCN for the Project now.

Q. **What action should the ICC take on RI's request for an Order under Section 8-503 of the PUA, given the information provided by RI?**

A. The ICC should deny the request for an Order under Section 8-503 of the PUA. As a merchant facility that has not been demonstrated to have a public need under the applicable regional planning standards – indeed, RI did not even submit the Project to PJM as one that has such public benefits – RI's request for an Order under Section 8-503 should be rejected. Moreover, this request appears baffling because RI witness Berry acknowledges that the appetite of generators to pay for the costs of the Project is uncertain and that RI will only build the Project if future market developments permit it to be financed.[8] Since no one, not even RI, can be sure if RI will build the Project, RI cannot justify an order unconditionally directing that it be built.

Q. **Do these recommendations reflect opposition by ComEd to new transmission construction in general or to merchant transmission projects in particular?**

A. No. ComEd does not oppose new transmission projects in general and it does not object to merchant transmission facilities, in particular. Indeed, merchant transmission facilities, in appropriate circumstances, can protect customers from costs by imposing risks on private investors who voluntarily assume them. But, the function of this Project, its design, the hundreds of millions of dollars of other upgrades it may require, its potentially risky reliability implications, its uncertain and unspecified financing, and even its continued status as a merchant project all remain subject to material uncertainties.

[8] RI Ex. 10.13, 2:27 – 4:111; *see* Response to Data Request Staff RJZ → RI 1.18 ("It is unlikely that the Project would be built with only 60% of the capacity contracted.").

Those uncertainties, and the reliability and financial risks they entail, including to Illinois delivery customers, are far too great to warrant issuance of a CPCN at this time. They are certainly too great to support issuing an ICC Order mandating the line's construction.

III. THE PROJECT IS INSUFFICIENTLY DEVELOPED AND SPECIFIED TO WARRANT CERTIFICATION

A. Overview

Q. **Is the Project sufficiently described and specified in the Petition and RI's direct testimony to allow an analysis of the full impacts of its potential construction and operation of the system and Illinois delivery customers?**

A. No. In important respects, the Proposal is not fully described. Nor could it be, because it is not complete. Basic factors, which have typically been firmed up in advance of a CPCN filing, here remain open. In addition, there appear to be inconsistencies in how the Project has been described at the ICC and elsewhere. The importance of these gaps and inconsistencies are great. Until the gaps are filled and the inconsistencies resolved, ComEd cannot assess the final impact of the Project on ComEd's transmission system or customers. Nor, in my opinion, can the ICC.

Q. **What, in summary, are the uncertainties, gaps, and inconsistencies to which you refer?**

A. The major issues to which I refer include:

- To build and operate the Project, and connect it to the existing ComEd transmission system in a reliable manner, hundreds of millions of dollars in additional upgrades may be required. Those upgrades are not limited to the

ComEd system in Illinois, but could include other transmission systems, some in other states. We simply do not know what will be required. For this type of project, those upgrades are the responsibility of the project developer and the Project could not be integrated, as proposed, without them. Yet, none of these upgrades are finalized and, in some cases, they are not even known at this time. The range of possible upgrades is not described in the Petition. Nor are the studies concerning these upgrades discussed by RI witnesses.

- The ICC cannot be certain whether or not RI will challenge the ability of PJM to assign the costs of certain upgrades to RI. Moreover, the ICC cannot be certain whether RI will at some point in the future, after this Docket is over, attempt to convert all or part of the Project from a merchant transmission project to a rate-base transmission project, thereby imposing costs on Illinois delivery customers.
- As I mentioned above, the nature of the generation to be delivered, *i.e.*, whether the Project can or will deliver 100% renewable energy, cannot be assured and RI's treatment of that fact appears to be inconsistent. The ICC cannot be sure what type of generation, if any, will contract with RI to utilize the line. This uncertainty also relates to how the Project is analyzed for reliability purposes.
- Whether and how those lines will connect to facilities at Collins Station or if, in fact, the connection will be to Collins Station itself or to some alternate connection point or points has not been finalized.
- Finally, there is a basic uncertainty as to whether or not the market will support the cost of the Project as a whole, i.e., whether any customer(s) will contract with

RI in sufficient volume to support the required investment, and thus whether the Project actually will be built.

In my opinion, the ICC cannot reach a final regulatory conclusion concerning the Project, its certification, and a possible Section 8-503 order, absent this information.

B. How RI Addressed the PJM Planning and Interconnection Process

Q. **Please explain the regional planning process for new transmission facilities?**

A. As individual utilities joined regional transmission organizations such as PJM and MISO, those regional organizations took over responsibility for planning the transmission system. Using a formal process that considers stakeholder input, these organizations each develop a regional transmission plan. In PJM, this is the RTEP; in MISO it is called the MISO Transmission Expansion Plan ("MTEP"). The PJM regional planning process is set out in detail in Schedule 6 to the PJM Operating Agreement, entitled "Regional Transmission Expansion Planning Protocol," which is filed with FERC and any changes must be accepted by FERC.

As part of this process, the regional planners also apply criteria to decide whether upgrades need to be made to the transmission system. The most common driver, and the one most familiar to the ICC, is reliability. Regional planners test to ensure that their transmission system meets all the mandatory reliability standards promulgated by the North American Electric Reliability Corporation ("NERC"), by regions in which the systems are located (such as ReliabilityFirst and SERC for ComEd and Ameren, respectively), and local reliability criteria. The regional planners also determine whether an upgrade could relieve congestion in an economic manner, meaning that the benefits of the upgrade exceed the costs by a specific margin. Regional planners have, or in compliance with FERC Order No. 1000 will, also consider public policy requirements which are federal, state and local statutes and regulations.

Q. **How does the PJM RTEP process determine whether there is a need for a new transmission facility sufficient to support its inclusion in rate base?**

A. A proposed project must meet one or more requirements to be included in the RTEP. The first, and by far the most prevalent, is reliability. As PJM states, "The Regional Transmission Expansion Plan shall conform at a minimum to the applicable reliability principles, guidelines and standards of NERC, ReliabilityFirst Corporation, and SERC, and other Applicable Regional Entities in accordance with the planning and operating criteria and other procedures detailed in the PJM Manuals."[9]

A closely related criterion is operational performance. This criterion is met if PJM determines that there are operating difficulties that require expansion of the system, even if reliability criteria can be met. An example would be where excessive switching of transmission lines in and out of service would be required to prevent overloads or voltages outside of the acceptable range.

A third driver is market efficiency. Simply stated, if PJM finds that new transmission can relieve congestion, thus lowering costs to customers, and the cost of the new transmission is less than the reduction in congestion, PJM will require new economic transmission to be built. There are strict metrics governing market efficiency projects

[9] Section 1.2(d) of Schedule 6 to the PJM Operating Agreement.

and in PJM the benefit to cost ratio must be greater than or equal to 1.25.[10] There are other requirements in the PJM Operating Agreement for system expansion, such as Stage 1A Auction Revenue Rights[11] or enhancements required as a result of coordination with other planning regions.[12]

The PJM RTEP only includes merchant facilities, such as RI, or other enhancement or expansions requested by an entity (referred to as Participant-Funded Projects) provided such projects are consistent with all reliability and operating criteria and the requester is responsible for all costs of the facilities which includes design, construction, operating and maintaining those facilities. Such projects are, however, not required to meet PJM planning criteria, such as being needed for reliability, operating, or market efficiency reasons.[13]

Procedurally, as stated in Schedule 6 to the PJM Operating Agreement, "The Regional Transmission Expansion Plan shall consolidate the transmission needs of the region into a single plan which is assessed on the bases of (i) maintaining the reliability of the PJM Region in an economic and environmentally acceptable manner, (ii) supporting competition in the PJM Region, (iii) striving to maintain and enhance the market efficiency and operational performance of wholesale electric service markets and (iv) considering Public Policy Requirements."[14] The recommendations of PJM Staff are

[10] Section 1.5.7(d) of Schedule 6 to the PJM Operating Agreement.

[11] Section 1.5.3(h) of Schedule 6 to the PJM Operating Agreement.

[12] Section 1.5.5 of Schedule 6 to the PJM Operating Agreement.

[13] Section 1.5.6(i) of Schedule 6 to the PJM Operating Agreement.

[14] Section 1.4(a) of Schedule 6 to the PJM Operating Agreement.

reviewed by the Transmission Expansion Advisory Committee ("TEAC") and all RTEP projects must be approved by the PJM Board of Managers.[15]

Q. **How can a transmission project that cannot show a public need through the RTEP process nonetheless be constructed?**

A. Such projects are allowed and can be constructed if they pass the "'no harm' to reliability" test. To qualify, the developer of such a project requests that PJM analyze the project to ensure all reliability standards are met. If they are not, the developer will have to include any additional upgrades required to maintain reliability. The largest categories of such "no harm" projects are new or enlarged generator interconnections and merchant transmission interconnection projects.[16]

Q. **What is the process that RI would have to complete in order to tie its proposed new transmission facilities into the existing PJM transmission system?**

A. To tie its proposed new transmission facilities into the PJM transmission system, RI must first make a request to interconnect and be assigned a queue position. As explained later, that much has occurred. Thereafter, interconnection requests, whether for generators or merchant transmission, are processed according to the PJM tariff, which requires the customer, in this case RI, to pay all the costs of studies to determine what facilities are needed for a reliable interconnection, the cost of the facilities needed to interconnect to the PJM transmission system, and all additional facilities, referred to as "network

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[15] Section 1.6 of Schedule 6 to the PJM Operating Agreement.

[16] This category also includes "supplemental projects" by transmission owners, such as equipment replacement with more modern equipment with greater capability.

upgrades" that PJM determines are needed for a reliable interconnection. This is different than a project which meets RTEP criteria and passes one of the PJM need tests, where "load," *i.e.*, customers, pay the costs of the new transmission facility. The two processes – interconnection, where the requesting customer pays, and RTEP where the load pays –are mutually exclusive.

Q. **How does the PJM Interconnection Process work for merchant and interconnection projects such the Project?**

A. In addition to expansion of the transmission system as described above, PJM also has processes to evaluate requests from generators and merchant transmission projects such as RI to interconnect to the PJM transmission system. For simplicity, I will refer to these parties as the "interconnection customer." As opposed to RTEP transmission upgrades, which are required to meet the objectives of the PJM expansion plan, interconnection customers propose voluntary projects and do not have to justify the need for those projects to PJM. In accordance with FERC rules and regulations, PJM must include in its tariff processes for such interconnections such as the types of studies, the types of agreements and the terms of those agreements and requirements for funding of any costs of any facilities required to allow the interconnection.

The PJM interconnection process requires a number of studies to determine the reliability impact of a project on the system and the necessary facilities and network upgrades to accommodate the project. The studies, in their order, include the Feasibility Study, System Impact Study, and Facilities Study.[17] These studies are sequential with

[17] *See* Sections 36.2, 203, 205, and 206 of PJM Tariff.

each study being more detailed. An important result of these studies is to inform the interconnection customer what new facilities must be installed to (1) interconnect to the transmission system (interconnection facilities); and (2) upgrade the existing transmission system to ensure that the interconnection meets all applicable reliability standards (network upgrades), and their associated costs. These studies are essential because until the Facilities Study is completed, the facilities that need to be installed and the costs of those facilities are not known. Because the facilities that must be installed to ensure the reliable interconnection of a given customer may depend on whether an interconnection customer in an earlier queue position continues to go forward with its project, PJM must update the System Impact Study if higher queued projects are cancelled to account for the changed impacts on the system. The updated study is known as a re-tool study.

Q. **How must the costs of interconnection projects be determined and paid?**

A. As I stated, under the PJM Tariff, interconnecting customers are responsible for the costs of all interconnection facilities and network upgrades required to maintain reliability. This methodology is sometimes referred to as 'but for' cost allocation because the interconnection customer is responsible for the costs of all facilities that would not be required 'but for' its interconnection project.

The next step is to conduct a Facilities Study for developing detailed engineering designs and cost estimates of the required facilities and network upgrades. After completion of the Facilities Study, the interconnection customer and the interconnected transmission owner must sign an Interconnection Service Agreement.

While the interconnection customer is not required at that point to complete the interconnection project, no work is performed on the interconnection facilities and network upgrades until the interconnection customer, PJM and the interconnected transmission owner sign a Construction Service Agreement. If the interconnection customer wishes the work to proceed before all the studies are complete, the interconnection customer may sign an Interim Construction Service Agreement. Under the PJM tariff, the interconnection customer has the option of constructing the network upgrades or paying the interconnected transmission owner or other affected transmission owners to site and construct the network upgrades. In appropriate cases, upgrades also could be required on the system operated by MISO.

C. <u>Remote Upgrades and their Costs</u>

Q. **What does RI's direct testimony say about the studies to determine the upgrades required for interconnection of the RI Project, and the costs thereof?**

A. Dr. Galli states that PJM has completed a Feasibility Study for three of RI's active interconnection requests (Queue Numbers S57, S58, and U3-026) and has completed an initial System Impact Study for two of those requests (Queue Numbers S57 and S58). He states that PJM's light load analysis "has delayed the start of the Facility Study" but does not make clear that this light load analysis is actually part of PJM performing an updated System Impact Study.[18]

[18] Galli Dir., RI Ex. 2.0, 9:176-184. I note that while no testimony update was filed on this question, Dr. Galli and RI witness Mr. Detweiler filed revised and new exhibits following an Agricultural Impact Mitigation Agreement between RI and the Illinois Department of Agriculture.

Q. **What is the current status of the interconnection-related studies of the Project at PJM?**

A. At this point, PJM has completed the Feasibility Study for RI's three interconnection requests, Queue Numbers S57, S58, and U3-026. These requests are for 300 MW, 400 MW, and 492 MW firm injection rights into the PJM system, respectively. For S57 and S58, PJM also has conducted a System Impact Study, a re-tool System Impact Study issued in November 2012 and presently is conducting a second re-tool System Impact Study. For U3-026, PJM has conducted a System Impact Study issued in November 2012 and is planning to perform a re-tool System Impact Study in the near future.

Q. **What studies remain to be performed?**

A. As I stated above, PJM is in the process of conducting a second re-tool study for Queue Numbers S57 and S58 and at some point in the future will be conducting a re-tool study for Queue Number U3-026. As part of those studies, PJM will be conducting an updated stability study which I describe in more detail later. Following completion of those re-tool System Impact Studies, PJM then will conduct the Facilities Studies.

Q. **Given the incomplete state of the studies, can the ICC determine what upgrades will be required or how much they will cost?**

A. No. Until all of these re-tool System Impact Studies and the Facilities Studies are completed, neither RI nor ComEd knows what facilities will be required by PJM for RI to reliably and safely interconnect to these ComEd system. Until the Facilities Study is completed, the estimated costs of the new facilities will not be known.[19] As with any interconnection project, however, under current rules RI will be responsible for the actual costs of the interconnection facilities and the 'but for' network upgrades if it elects to proceed. Also, as I describe later, MISO is conducting what it refers to as a "no harm" study because the west end of the Project will interconnect with MISO.

D. <u>Uncertainties Potentially Impacting Reliability</u>

Q. **Can you explain how a DC line connecting generators in Iowa to the transmission system in Illinois can affect the reliability of the system as a whole?**

A. New lines connecting generators to the transmission system can cause overloads of existing lines violating reliability criteria. In addition, the lines connecting new generators can cause congestion, which while not violating reliability criteria can increase costs to some customers. The new lines can result in the system becoming unstable during and following various disturbances. Finally, new lines can cause an increase in short circuit current requiring new circuit breakers that are able to interrupt the increased short circuit current.

Q. **Does RI's Petition and direct testimony identify the facilities that will need to be built in order to protect the reliability of the system?**

A. No. RI has not identified the network upgrades required to ensure the reliability of the ComEd system. This is not surprising because as I state above, PJM has not completed all the necessary studies to identify and assess such impacts.

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[19] It also is possible that the Facilities Studies will determine that additional upgrades, not identified in the System Impact Studies, will be required.

1. Steady-State Thermal and Voltage Violations

Q. What is the most current information now available concerning the upgrades required to protect against overloading and low voltages?

A. RI witness Dr. Galli testified that at the time testimony was submitted, PJM was conducting a re-tool of the System Impact Study.[20] Since that time, PJM has completed that re-tool study for the S57 and S58 requests and a System Impact Study for the U3-026 request and published those studies in November 2012.[21] Those studies indicate that to maintain the reliability of the ComEd system, and other portions of the PJM system, while accommodating all three RI interconnection request will require a new 90-mile 765kV line, 50 miles of which will be located in Illinois, between ComEd's Collins Station and AEP's Meadow Lake Station,[22] located in White County, Indiana. The cost of this line, which was estimated by PJM in consultation with ComEd, is expected to cost $330 Million. Additional upgrades on the AEP system ($115 Million from Sorenson – East Lima) and completion of three MISO MVP upgrades (Meadow Lake – Greentown 765kV, Meadow Lake 765/345kV autotransformers and Reynolds – Hiple 345kV) also are required to assure reliability of the PJM transmission system. The general location of these upgrades is shown below in Figure 1.

[20] Galli Dir., RI Ex. 2.0, 9:176-184.

[21] Response to Data Request ComEd → RI 2.01, Attachments 4, 5.

[22] Because of a decision of the MISO to move the station to New Reynolds, this line likely would connect to NIPSCO's future New Reynolds substation.

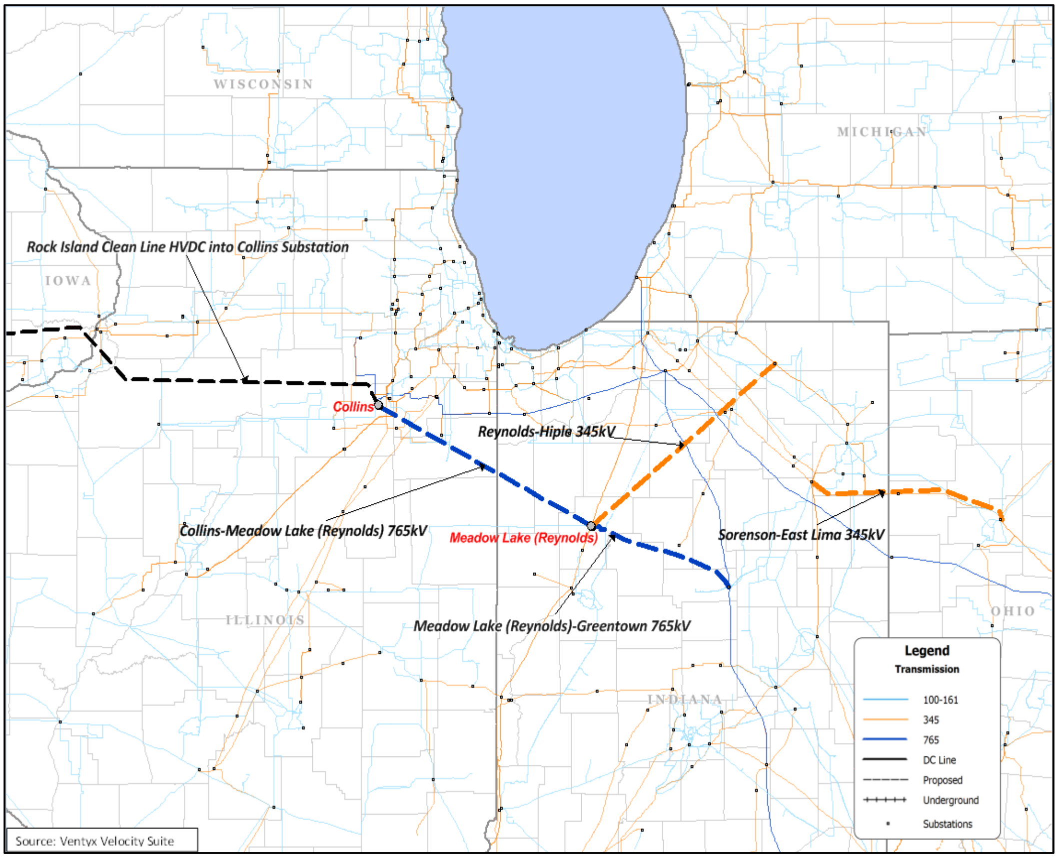

Figure 1

Q. Why would a new Collins – Meadow Lake 765kV line be required if the Project is constructed and operated as proposed?

A. As I stated above, the Collins – Meadow Lake 765kV line is required to maintain the reliability of the ComEd and other PJM transmission systems. Specifically, PJM found that under light load conditions (*i.e.*, circumstances where there is less "local" load to soak up an injection of power), forty transmission facilities become overloaded, most of which are on the ComEd system. In addition, the Project contributes to multiple voltage violations on the ComEd and other transmission systems. The Collins – Meadow Lake 765kV line and other upgrades mitigate those violations.

2. Protecting System Stability

Q. **What other reliability issues must be addressed?**

A. In addition to thermal and voltage limits, interconnections must not cause instability of the system or increased short circuit duties that would require existing circuit breakers to be replaced.

Q. **Did PJM perform a short circuit study on the impact of the RI Project on the PJM operated transmission system?**

A. The short circuit analysis that was referenced in the November 2012 System Impact Study found no over-dutied circuit breakers.

Q. **What is system stability and why it is important?**

A. System stability analyzes the ability of the electric system to return to a new operating state following a disturbance on the system such as a short circuit. Transmission engineers call these issues "stability" to distinguish them from steady state thermal and voltage issues. These studies are also sometimes referred to as dynamic and stability studies because historically stability studies only covered time periods less than a second and dynamic studies analyzed a longer time period (a few seconds) to ensure that the system returned to a new stable operating state. For simplicity I will refer to these studies as stability studies.

A system is considered to be stable if, following a disturbance, the power system settles into a new operating state in a finite time. If this does not occur, the system is considered to be unstable. System stability is important because disturbances occur on the system and if the system cannot return to a new operating state, generators will no longer be synchronized with the rest of the system and must be removed from the system and/or suffer damage, transmission lines can trip and load can be lost. Unlike overloads which I discussed above, which analyze the steady state conditions, stability studies look at the conditions over periods of less than a second through several seconds. This time period is important because there is no time for operator action to remedy stability problems. Stability studies simulate a disturbance (such as a short circuit and the removal of transmission lines impacted by the disturbance) and study how the system reacts to the disturbance and whether the system ends up in a new state that does not result in generator, transmission and load outages. In some cases where a stability study finds that the system is not stable, the system can cascade and result in a large-scale blackout.

Q. **Did PJM perform a stability study on the impact of the RI Project on the PJM operated transmission system?**

A. Yes. The stability analysis that was referenced in the November 2012 System Impact Study found that the system dynamic performance with 3,500 MW of energy delivered by RI failed to meet applicable NERC, PJM and ComEd standards.[23] This means that without mitigation, the transmission system was unstable and thus did not meet the reliability criteria. The November 2012 report also stated that an updated dynamics model is required for PJM to perform additional dynamic and stability studies.

Q. **What additional studies and clarifications are currently pending?**

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[23] Response to Data Request ComEd → RI-2.01, Attachment 4, p. 12.

A. As Dr. Galli stated in Data Response ComEd → RI 2.20, PJM is conducting a second re-tool study. RI has not updated its testimony based on the results of the November 2012 System Impact Study. As of May 28, 2013, PJM notified RI that PJM will "conduct all studies associated with Transmission Interconnection Requests without regard to the resources which may be delivered across these facilities in the future."[24] As of June 6, 2013, RI is trying to "understand the implications" of PJM's determination.[25] RI acknowledges that "PJM and MISO, along with ComEd and neighboring utilities are the entities charged with ensuring that the Project will be planned and interconnected in a secure and reliable manner."[26]

Q. **Are there open issues concerning even these yet to be completed studies?**

A. In this re-tool study, it is not clear that the interconnection will be modeled by PJM in the same way that RI intends to use the Project – to deliver 3,500 MW of wind into Collins. RI has stated that it has questioned whether the dispatch PJM used for the November 2012 System Impact Study, *i.e.*, PJM wind generators being dispatched at 80% of their nameplate value, in the light load analysis as documented in PJM Manual 14B, is appropriate for the RI interconnection. RI has stated that the assumptions made by PJM in its light load analysis did not take into account certain "facts" which bring into question whether PJM should be modeling the use of the line to deliver 100% wind energy.[27] RI specifically "posited that PJM shouldn't be assuming that [RI is] a wind-

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[24] Response to Data Request ComEd → RI 3.01, Attachment 2.

[25] Response to Data Request ComEd → RI 3.21.

[26] *Id*.

[27] Response to Data Request ComEd → RI 3.26.

sourced injection."[28] These "facts" include (1) RI does not own generation assets connected to the Project; (2) FERC denied RI's request to give preference to wind generation for use of the Project; and (3) FERC open access rules require RI to allow any eligible customer to purchase capacity or use service on the Project.[29] However, as to the first "fact," it is RI that will be negotiating with customers and while the second and third "facts" are legal restrictions placed on RI as a result of FERC's rules, RI, in its testimony and responses to data requests, has uniformly and continuously told the ICC that the purpose of the Project is to deliver wind energy and wind energy only. Yet, as RI's responses to data requests indicated, RI has told PJM that these "facts" "left an open question as to what dispatch assumption to make for the Project under PJM's new light load analysis" because PJM's dispatch in its System Impact Studies "ties a generator's dispatch level to its fuel-type."[30]

Q. **Where does this leave the overall status of the PJM stability study process?**

A. The PJM stability study process is still very much in flux. Thus at this point, ComEd does not know whether additional facilities will be required to meet the dynamic and stability requirements or whether operating restrictions will be needed, or how those requirements may affect the cost and economics of the Project. If PJM determines that operating restrictions are necessary to ensure reliability, any such operating restrictions would be inconsistent with the analyses presented by RI, which assume no operating restrictions. Until the final results of the stability studies are completed, which will occur

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[28] Response to Data Request ComEd → RI 3.10, Attachment 01.

[29] Response to Data Request ComEd → RI 1.28 revised.

[30] Response to Data Request ComEd → RI 3.02.

sometime in the future, not only will ComEd not know the requirements but RI cannot reflect those operating restrictions in its economic analysis.

Q. **Given this status, does the ICC have sufficient information to assess the impact of the Project on reliability and to assess what upgrades or other actions may be required to assure reliability?**

A. No. At this point, we do not know: (1) whether RI will agree with the new assumptions by PJM as stated in PJM's May 28, 2013 e-mail[31]); (2) assuming RI agrees with all the assumptions by PJM, the results of that study; (3) when PJM will issue that study; and (4) what, if any, network upgrades will be needed to maintain system reliability in order for RI to interconnect to the ComEd system.

Our concern is that the interconnection of the RI Project, as with any project, protect reliability and to do so the modeling must reflect the real expected use of the system. RI has been adamant in its filing that its intent is to deliver 3,500 MW of wind energy into ComEd.[32] Yet, as stated above, RI has been questioning whether that dispatch should be used by PJM for its light load analysis in the System Impact Study to determine which upgrades are necessary to ensure the reliability of the ComEd system.

E. <u>Important MISO Studies Are Also Not Complete</u>

Q. **You mentioned earlier that a MISO study process was also underway. What is the function of that process?**

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[31] *See* Response to Data Request ComEd → RI 3.01, Attachment 02.

[32] *See e.g.*, Skelly Dir., RI Ex. 1.0, 5:109 – 7:186.

A. Just as PJM is studying the interconnection of the Project at Collins 765kV, MISO will wish to study the interconnection at the western terminus of the DC line, given that the Project will be connected to MidAmerican's Lakefield Junction to Raun 345kV line.[33] MISO will be considering the impacts on a number of MISO transmission systems which could result in upgrades within MISO, such as on the Ameren-Illinois transmission system.

Q. **What is the status of the MISO study process?**

A. MISO has not started, much less completed its own 'no harm' study. Indeed, is not only unfinished, it does not yet even have a finalized scope. RI has agreed to provide parties in this Docket with a finalized scope and RI has committed to do so once the final scope is available.[34] No such finalized scope has yet been given to ComEd by RI. And, while ComEd believes that some new scope documents exist, because RI has not updated its response, it is unlikely that even those documents are final.

Q. **Has a study of the interaction between the PJM and MISO system, including possible loop flows, been completed?**

A. No. While the Draft Scope of Work states that "PJM will be contacted to coordinate the study, which will include generation dispatch," to date, ComEd is not aware of any study by MISO or PJM to determine the impact of possible loop flows on the ComEd system, and it is not clear that either MISO or PJM plan to perform such a study. This process

[33] *See* Response to Data Request ComEd → RI 1.27 Revised, Attachment 01 thereto; Response to Data Request ILA → RI 1.10, Attachment 08.

[34] Response to Data Request ILA → RI 1.10 Revised.

may not be easy. The draft System Impact Study Agreement provided by RI estimates that the study will take nine months to complete.[35]

In addition, MISO and PJM use different planning assumptions for their studies – MISO models wind generation at 90% in the shoulder peak while PJM models PJM wind resources at 80% and MISO wind resources at 100% during light load periods. Furthermore, MISO will be modeling wind at 20% for the summer peak, but RI claims that the wind to which it will connect will have a 35% capacity factor[36] and has requested a total of firm rights of 34% to inject on the PJM system. If RI maintains that position, a methodological dispute is possible.

Q. **What is the bottom line impact of the MISO study situation you have described?**

A. Until the MISO "no harm" study is complete and can be reviewed, no one will know the full impact on the ComEd and PJM systems of the Project and the generation that contracts to utilize the Project. Furthermore, it is unclear as to whether the MISO and PJM studies will be consistent until the MISO study is complete and available for review, and only then can PJM determine if additional studies are required. Until ComEd sees this study, it has no way of knowing if the particular connection to the MidAmerican system will cause reliability or congestion problems or whether MISO will require operating restrictions that are inconsistent with the assumptions used by RI.

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[35] Response to Data Request ILA → RI 1.10.Attachment 09 (attached to April 29, 2013 e-mail as document entitled Rock Island HVDC Study Scope 20130423 Redlines.docx).

[36] Skelly Dir., RI Ex. 6.0, 11: 227-229.

F. Functional Control of the Project Is Unclear

Q. Is it yet known which regional transmission organization will have operational control over the Project?

A. While RI has committed to turn over control to either PJM or MISO, RI has not decided which RTO would functionally control the Project.[37] As the stated purpose of the Project is to inject 3,500 MW of wind energy into PJM, it is the ComEd system and the rest of the PJM systems that will be affected most by the Project. ComEd sees no reason why control of the Project should not be turned over to PJM and does not understand the equivocation of RI. However, RI confirmed that it has not yet compiled reasons for not turning over functional control to PJM.[38] Further, a coordination agreement between PJM and MISO has not been developed, let alone executed. Until such an agreement is in place, this is yet another reason why ComEd cannot know whether the reliability of its system is fully protected.

G. Other Issues Regarding the Interconnection Are In Limbo

Q. Are there other material interconnection issues that remain unresolved?

A. Because the second re-tool studies for queue positions S57/S58 and the retool study for U3-026 are not complete and RI has requested additional studies that assume different physical interconnection points (and at a different voltage) from that described in RI's direct testimony, neither ComEd, PJM, RI nor the Commission knows exactly how RI will interconnect with the ComEd system. While the November 2012 System Impact

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[37] Skelly Dir., RI Ex. 1.0, 38: 890-893; RI Ex. 10.13, 4:117-118; Response to Data Request ComEd → RI 3.14 Revised.

[38] Response to Data Request ComEd → RI 3.14 Revised.

Study shows an interconnection of the Project at ComEd's Collins 765kV substation, RI has not finalized its plans for the lines that will connect the converter station in Illinois to the ComEd system, and, in addition, has asked PJM to analyze alternative interconnection points.[39] In April 2013, RI had phone call with PJM to discuss, among other issues, tying into ComEd transmission lines adjacent to the possible Illinois converter station location in Grundy County.

On a preliminary basis, this option, on which RI has not decided, would require adding another double-circuit 345kV line. If RI were to pursue this option, this new interconnection and the new double-circuit 345kV line would be required instead of the lines from the Grundy County location to Collins, assuming the Illinois converter station is located in Grundy County.[40] At this point, PJM has not issued a report on facilities needed for a reliable interconnection at these alternative interconnection points, and until an Interconnection Service Agreement is signed between PJM and RI, neither the interconnection points nor the route of the AC lines between the Illinois converter station and the ComEd system will be known.

Q. **Are there also additional open issues if RI continues to pursue an interconnection at Collins?**

A. Assuming RI intends to interconnect into Collins, RI's proposal still leaves a number of unanswered questions. According to the Petition, RI intends to bring 3-345kV AC lines

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[39] Response to Data Request ComEd → RI 1.07; RI → ComEd 2.01 Attachment 07 (unnumbered pages 5-9).

[40] Response to Data Request ComEd I → RI 3.10, Attachment 01.

into ComEd's Collins Station.[41] In order to interconnect to Collins at 765kV, RI would have to add transformers to step the voltage up to 765kV. But RI has not stated how this would be accomplished.

Q. **Do any other proposed RI facilities raise open questions?**

A. Yes. While RI states that the "Project may also include additional transformation facilities to be located on land owned by Rock Island adjacent to, and from which connections will be made directly into, the Collins substation,"[42] RI also states that it anticipates that the transformation facilities "can be located within the Collins substation."[43] RI's legal description of Preferred Route (Study Route F) and Proposed Alternative Route G, both contemplate running the RI 345kV AC lines terminating "at the Rock Island transformer substation at the existing Collins substation."[44] RI has not had any discussions with ComEd regarding the availability of space at Collins for RI's equipment.[45] Nor does it appear that RI has any property under its control where it would locate the transformation facilities.[46] Given that RI will have to run 765kV facilities from those transformation facilities into the Collins 765kV yard, it is essential that ComEd know where and how such lines will be located.

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[41] Petition at ¶¶ 6, 58; RI Ex. 2.0, 5:106 – 6:118.

[42] Petition at ¶ 6.

[43] Petition at ¶ 71.

[44] RI Exs. 7.4, 7.5.

[45] Response to Data Request RI → ComEd-1.09.

[46] Data Response RI → ILA 1.24 lists three pieces of property for which RI has options, none of which would be located near where RI has depicted such transformation facilities.

Also, the Preferred Route shows 345kV lines going into a 345kV/765kV Transformer Substation located in ComEd's Collins substation.[47] However, RI states that the 345kV/765kV transformation would be required if the Project cannot connect directly to ComEd's Plano-Collins 765kV line (one of the alternative interconnections discussed above) or the 345kV circuits cannot be 'accommodated' at ComEd's Collins 345kV substation.[48] Therefore, there is no firm plan as to how RI will interconnect to Collins.[49]

In short, at this point, RI has not provided the information required for ComEd to determine the impact on its facilities and the system of the proposed interconnection at or near Collins.

H. Uncertainties Regarding Project Operation

Q. **Finally, do you have any operational concerns you wish to being to the attention of the ICC?**

A. Yes. RI does not have any maintenance or spare equipment plans at this time.[50] Nor does it appear that they have plans for a 24/7 response in case of physical failure. These are particularly important given that the line is very long and uses a single, common set of poles.

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[47] Petition Attachment 6, pp. 18-19; Detweiler Dir., RI Ex. 7.0, 8:177-99.

[48] Response to Data Request RI → ComEd-1.08; Galli Dir., RI Ex. 2.0, 6:111-13.

[49] Response to Data Request RI → ComEd-1.09.

[50] Response to Data Request ComEd → RI 1.12.

IV. SIGNIFICANT RISKS CONCERNING PROJECT COSTS AND BENEFITS SHOULD BE ADDRESSED PRIOR TO CERTIFICATION OF THE PROJECT

A. Costs Potentially Imposed on Illinois Delivery Customers

Q. **How should a merchant project be funded?**

A. As I mentioned above, projects that do not meet the PJM RTEP need criteria can still be built, provided that they do not degrade the reliability of the PJM transmission system, if the project developers bear all the costs of such projects, including required upgrades.

Q. **Does that mean that a project that has not shown a public need through the RTEP process cannot affect Illinois customers or the Illinois delivery system?**

A. Unfortunately, RI has not made that commitment. The ICC should be concerned about several possibilities.

First, the developer of a merchant project could, at a later time, attempt to gain approval of all of part or the project in an RTEP. The consequences of converting all or part of a merchant project to an RTEP project would mean that load customers would have to pay for all or part of that project. That change could be attempted after the ICC approved a CPCN, thereby removing from the ICC the ability to evaluate whether the changed circumstances would have affected its decision. This is especially significant here because RI paradoxically treats higher Project costs as creating a greater economic benefit[51] because, as RI modeled the Project, costs are all borne by contract users. To the extent all or part of a project becomes an RTEP project, costs of the project (or a part of the costs) would be borne by customers. Under that circumstance, costs are again costs, not benefits.

[51] Responses to Data Requests RI → Staff RJZ 1.08 and 1.14.

Second, the Project could result in additional congestion even though all reliability violations would be mitigated. Congestion could result in additional impacts to Illinois customers and would be determined as a result of the studies I discuss below.

Third, even an entity proposing a purely merchant project has the choice of constructing any additional facilities or requiring the incumbent transmission owner, such as ComEd, to construct those facilities.

Q. **Can the ICC be certain that the Project will remain a 100% merchant project that will be paid for only by persons who voluntarily agree to use the line?**

A. No. RI can change its mind and ask PJM or MISO to evaluate the project under the criteria for their regional plans. This has occurred before in PJM, in cases involving Primary Power[52] and Central Transmission.[53] RI could also attempt to transform part of the Project into a rate-based project while maintaining the rest as a merchant charging market-based rates. Of note, RI has expressed interest in potentially challenging PJM's light load analysis which could shift costs for the network upgrades required by PJM's reliability analysis to load customers. Finally, loop flows from the generators in MISO connected to the Project would impact the PJM system and in that case, any upgrades would have to be paid for by load.

Q. **What do RI witnesses say about the potential costs and risks to delivery customers?**

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[52] *Primary Power LLC*, 131 FERC ¶ 61,015 (2010), *order on reh'g and clarification*, 140 FERC ¶ 61,052 (2012), *appeal docketed sub nom*, *Public Service Electric & Gas Co. v. FERC*, No. 12-1382 (D.C. Cir. Sept. 16, 2012).

[53] *Central Transmission LLC v. PJM Interconnection, L.L.C.*, 131 FERC ¶ 61,243 (2010), *order on reh'g*, 140 FERC ¶ 61,053 (2012), *appeal docketed sub nom*, *Public Service Electric & Gas Co. v. FERC*, No. 12-1382 (D.C. Cir. Sept. 16, 2012).

A. Even though RI acknowledges that under current law and as the Project is now presented "it is responsible to pay for all ['but for'] upgrades," it is not clear whether or not RI will try to shift the costs of interconnection-related network upgrades to ComEd's customers rather than paying 100% of those costs.[54]

RI Witness Skelly has testified that Clean Line and RI "do not *currently* plan to request cost recovery for the Project through regional cost allocation processes."[55] (emphasis added) Mr. Skelly further states that RI *anticipates* recovering its costs from suppliers and buyers who contract to use the Project.[56] However, Mr. Skelly also testifies that while "[t]here is currently no mechanism in place for inter-regional allocation of the costs of a transmission facility such as the Rock Island Project ... [i]f a mechanism for inter-regional cost allocation were to be developed and implemented, and were widely used by transmission developers and their customers, Rock Island could find it necessary to utilize this mechanism as well, for competitive reasons."[57] RI has reiterated that while RI has "no current plans" to request MISO or PJM to study the Project to be cost allocated, RI does not rule out making such a request in the future if cost allocation rules change in the future.[58]

Moreover, RI's ultimate parent, Clean Line Energy Partners LLC ("Clean Line"), has actively advocated at FERC for new rules that would allow some costs of merchant

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[54] *See* Response to Data Requests ComEd → RI 1.31 Attachment 01; ComEd → RI 3.17 Attachment 01 (July 5, 2013 e-mail).

[55] Skelly Dir., RI Ex. 1.0, 15:405-406.

[56] *Id.*, 15-16: 408-412.

[57] *Id.*, 6: 416-421

[58] Response to Data Request ComEd → RI 1.19.

facilities to be considered for rate base cost allocation. FERC denied the request, not on substance, but because Clean Line's request was beyond the scope of Order No. 1000.[59] I note that RI claims that the Project provides reliability benefits and therefore could qualify for regional cost allocation rather than a merchant project today if the Project passed PJM and/or MISO planning criteria.[60]

Therefore, it is not clear whether or not RI will try to shift the cost of the Project to ComEd's (and other PJM) customers. This lack of a firm commitment to follow the "merchant transmission" model where subscribers pay for the cost of a project also undercuts RI's economic analysis where costs incurred by RI turn into benefits to Illinois. Without an unequivocal commitment not to shift costs of the Project to unwilling customers, RI's entire analysis of least cost is undermined.

Q. **You mentioned an additional concern about loop flows. How could loop flows result in costs to Illinois delivery customers?**

A. Because PJM's interconnection study only looks at the injection of energy at the interconnection point of RI with PJM, any loop flows from MISO are not modeled in the PJM study. This would not be an issue if the MISO generation were connected only to the west end of the Project, and not at the same time connected to the MidAmerican system. However, since the generation will also connect to MISO system, the possibility of loop flows exists. The loop flows could result in reliability problems on the ComEd system. Once PJM identifies such problems, PJM would find solutions as part of its

[59] *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,2014 at P 443 (2013)

[60] Response to Data Request ComEd → RI 1.19.

RTEP process. Hence, if these solutions were not identified during the interconnection process of the Project and the cost of these solutions were assigned to RI, they will be classified as baseline RTEP reliability upgrades. The cost responsibility for these RTEP upgrades, as opposed to interconnection-related 'but for' upgrades, would fall on the load customers in the ComEd zone and other load-serving entities within PJM.

B. <u>Uncertainties About Claimed Economic Benefits</u>

Q. **Is it accurate to describe the RI Project as one that, if built, will deliver 100% wind-generated or 100% renewable electricity to Illinois customers or PJM?**

A. No, as I noted earlier, FERC rejected RI's request to allow a preference for energy from renewable resources.[61] Also, RI itself has argued to PJM that it should not model the use of the line to deliver 100% wind energy.[62] RI specifically told PJM that PJM should not assume that RI should be modeled as "a wind-sourced injection."[63] And, given the acknowledged market uncertainties, no one can predict at this time if sufficient, or any, renewable generation will contract with RI to transmit energy over the line or whether other generation will want to do so in order to access the PJM market.

Q. **How does this affect the claimed benefits of the Project?**

A. First, RI witnesses Dr. McDermott's and Mr. Berry's analyses assume 100% utilization of the Project by wind.[64] Those analyses do not evaluate use of the Project "without

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[61] *Rock Island Clean Line LLC*, 139 FERC ¶ 61,142 at P 31 (2012).

[62] Response to Data Request ComEd → RI 3.26.

[63] Response to Data Request ComEd → RI 3.10, Attachment 1.

[64] Response to Data Request ComEd → RI 3.06; ComEd → RI 3.07.

regard to the resources which may be delivered across these facilities in the future."[65] If the PJM studies are modeled on other than 100% usage by wind generation, as RI has apparently requested, then the analyses performed by Dr. McDermott and Mr. Berry need to reflect the same assumptions. Those analyses would, of course, also need to take into account any operating restrictions that PJM may determine are necessary for reliability.

V. OTHER CONCERNS WITH RI'S SUBMISSIONS

Q. **Please put aside for a minute issues relating to the sufficiency of the data required to evaluate the Project on reliability and economic grounds. Do you have any other concerns about the testimony provided by RI in support of its Petition?**

A. Yes. I question RI's claims concerning "loss of load" benefits and transfer capabilities.

A. RI's LOLE Claims are Unsubstantiated

Q. What are "LOLE" studies?

A. LOLE stands for Loss of Load Expectation. These studies are performed to determine the reserve margin that is required in order to meet a specific frequency where generation would be insufficient to serve firm load. These studies use probabilistic methods and account for rates of generator forced outages, generator maintenance schedules, uncertainty in the load forecast and transmission limitations.

Q. **Are RI's claims of an LOLE benefit accurate and worthy of being relied on by the ICC?**

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[65] Response to Data Request ComEd → RI 3.01 Attachment 02.

A. No. RI contends that the new capacity "being brought to the Illinois market" will reduce the reserve margin to the State of Illinois and the Northern Illinois zone of PJM.[66] However, the study cannot be relied upon for five reasons.

First, the studies only modeled the Northern Illinois zone of PJM and Illinois, as islands.[67] Therefore, the study did not even attempt to perform a LOLE analysis in accordance with an accepted regional methodology. The PJM model, for example, includes all generation in PJM as well as generation outside PJM that PJM may rely upon for emergency assistance, thus lowering the PJM reserve requirement. There is in fact no recognized LOLE analysis for an isolated Northern Illinois zone. The deviation in the RI methodology is underscored by the fact that the required reserve level calculated in PJM's most recent study for 2015 (the same year as RI used) is different than calculated by RI for the Northern Illinois zone.

Second, RI purports to study LOLE for Illinois, when there is no recognized LOLE analysis for Illinois. Loads in Illinois are divided among PJM and MISO, each of which operates transmission assets and each of which independently conducts its own reserve analysis and maintains reserves. The effect of support from external resources on a RTO's installed reserve margin is analyzed by each RTO, and this analysis needs to be performed. But, RI did not consider transfer capability between the Northern Illinois zone of PJM and the rest of Illinois in its reserve calculations.[68]

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[66] Januzik Dir., RI Ex. 6.0, 17:357-365.

[67] Responses to Data Request ComEd → RI 1.44, 1.45, 1.46, 1.47.

[68] Response to Data Request ComEd → RI 1.44.

Third, RI has not contracted with any generators to use the line.[69] Until such time as generators have signed agreements, it is unreasonable to assume that those generators would provide capacity or reserve benefits.

Fourth, the assumption that only wind generators will use the line (and thus RI an hourly energy profile and maintenance schedules based on 100% wind generation)[70] is inconsistent with the position that RI has taken in arguing as to how PJM should analyze the interconnection of the Project. Other types of generation have different forced outage rates than do wind generators.

Finally, unlike typical generator interconnections, any generators that interconnect through the Project will be using an approximately 500-mile long line common-structure overhead line exposed to risks to which no analogous capacity resource is exposed. The LOLE analysis does not consider the fact that a severe weather event, such as a tornado, can cause an outage of a DC line, interrupting all the capacity the Project is injecting into PJM. Although as I stated above, the RI LOLE studies do not correspond to the method used by PJM and thus cannot be relied upon, I also wish to note that the studies assume 1,240 MW of capacity delivered by the Project[71] while RI's interconnection requests only request a maximum of firm injection rights of 1,192 MW.

B. <u>RI's Transfer Capability Claims are Unsubstantiated</u>

Q. Are RI's claims concerning increased transfer capability meaningful and reliable?

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[69] RI Ex. 10.13, 5-6:159-163.

[70] Januzik Dir., RI Ex. 6.0, 9:185-187, 11:224-229.

[71] *Id.*, 11:227-229.

A. No. RI contends that its transfer capability analysis indicates that First Contingency Incremental Transfer Capability ("FCITC") shows increased imports into the Northern Illinois sub-region of PJM.[72] However, RI's study and its conclusion have no real meaning as a measure of import capability into the Northern Illinois sub-region for seven reasons.

First, and foremost, RI uses a FCITC metric, which is not appropriate for this type of analysis. The RI analysis has no practical bearing on whether the Project provides a new benefit to ComEd customers. By way of background, the ICC is well aware of the debate on capacity deliverability between MISO and PJM during which numerous metrics have been used for varying purposes. The Organization of MISO States, led by Commissioner Montgomery of the Public Service Commission of Wisconsin, has been active in this area. For defining the maximum quantity of generation capacity that can be imported into the Northern Illinois sub-region of PJM, the metric that PJM uses is the Capacity Emergency Transfer Limit ("CETL"). That analysis takes into account the need to have sufficient import capability to serve load during capacity emergencies (*i.e.*, a capacity shortage in the load zone). To meet the PJM reliability criteria and standards, the calculated CETL must be greater or equal to the Capacity Emergency Transfer Objective ("CETO") that determines the minimum MW amount of generation capacity that is required to serve the load when there is a capacity shortage situation. That is the reliability measure used in the PJM planning process and that defines the PJM load deliverability criteria and generator reserve margins within a sub-region.

[72] Januzik Dir., RI Ex.6.0, 17:371-376.

I should note that for the 2016/2017 Planning Year, the CETO for the Northern Illinois sub-region, as calculated by PJM, is only 1,330 MW (2016-2017 Planning Period Parameters). So, PJM has shown the Northern Illinois sub-region import capability is more than sufficient to meet this value and does not need more import capability.

Second, in order to determine real-world import capability that can be relied upon, the calculation must take into account certain margins, known as Capacity Benefit Margin ("CBM") and Transmission Reliability Margin ("TRM"), or else the results are unrealistic. Calculations of FCITC do not take into account these or any other margins.

Third, valid transfer capabilities, which are concerned about the ability to import capacity during emergencies, only consider *firm* transactions. RI has asked only for 1,192 MW of Capacity Injection Rights (the equivalent of firm) for which the PJM system will be analyzed. Yet RI used 1,240 MW of wind capacity[73] and then added another 510 MW of incremental imports (1,750 MW – 1,240 MW), which is not firm, in its calculations. That is invalid.

Fourth, RI arbitrarily assumed that half of the wind capacity would be transferred outside of the Northern Illinois (ComEd) sub-zone of PJM. Yet, as RI admits, this was simply an assumption, with no production cost analysis and no accounting for the fact that many of the eastern PJM states are looking to meet their RPS requirements with off-shore wind.[74] Additionally, RI does not consider how much, if any, of the capacity is deliverable to the eastern PJM states.[75]

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[73] Januzik Dir., RI Ex. 6.0, 18:381-385.

[74] Response to Data Request ComEd → RI 1.51

[75] Response to Data Request ComEd → RI 1.47.

Fifth, the assumptions RI used in the transfer capability study, i.e., that half the capacity would be transferred to loads in the eastern PJM states, is at odds with the assumptions RI used for the LOLE study, which treated ComEd (Northern Illinois sub-region) as an island.[76] RI cannot claim a benefit of all capacity delivered to ComEd for one study and then claim benefits for half (actually more) of that capacity being delivered outside of the ComEd zone. Furthermore, this underscores the problem with the RI LOLE study which as stated above, treating ComEd as an island, when in fact, PJM treats ComEd as part of the integrated PJM system for its reserve margin analysis.

Sixth, as the System Impact Studies are not yet complete, no one – not RI, ComEd, PJM nor the ICC – knows what network upgrades will be required for RI to deliver the resources to the PJM load in a reliable manner. Without knowing that information, the results of the transfer capability study are simply not valid.

Finally, RI has made clear it has no generation under contract. And, of course, without real generation that has at least signed interconnection agreements (or in this case a contract with RI), any analysis is totally theoretical, putting aside the problems raised above.

VI. A SECTION 8-503 ORDER IS NOT APPROPRIATE IN THIS CASE

Q. Under what factual circumstances should the Commission issue a Section 8-503 order?

A. Section 8-503 of the PUA itself specifies that when the ICC finds additions "are necessary and ought reasonably be made" or new facilities are "necessary and should be

[76] Response to Data Request ComEd → RI 1.47.

erected", "the Commission shall make and serve an order authorizing or directing that such additions … be made … or such structure or structures be erected at the location, in the manner and within the time specified in the order …"

Q. **Does RI's testimony uniformly describe the Project as one that is "necessary" and to which they are committed?**

A. No. As I stated earlier, the Project has not been vetted under the PJM RTEP process as one that is justified by a public need, be it a reliability need, an operating need, or an economic need. It would be odd indeed for the ICC to issue an order directing the construction of an interstate bulk power project premised on public need when the FERC-jurisdictional planning process has not even been initiated.

Moreover, RI's executives expressly acknowledge that whether the Project can or will be constructed is an unanswered question. In the most recent amendment to RI's testimony on this subject, RI's CFO, Mr. Berry, testified that "permanent installation of facilities cannot and will not commence unless and until the need for the Project is actually established through the market test of transmission customers contracting for sufficient service on the transmission line to support and justify financings that raise sufficient capital to cover the total Project cost."[77] That has not occurred and whether it ever will occur is unknown. RI has further stated that "[i]t is unlikely that the Project would be built with only 60% of the capacity contracted."[78] These facts are not

[77] Berry Additional Supplemental Dir., RI Ex. 10.13, 4:107-110.

[78] Responses to Data Requests RI → Staff RJZ 1.18.

consistent with viewing the Project as a transmission addition essential to the public which the ICC should unconditionally order RI to construct.

VII. <u>CONCLUSION</u>

Q. Please summarize your conclusions and how they relate to the testimony you provide?

A. ComEd supports efficient and reliable development of the interstate transmission system. In this case, however, for the reasons I have explained in Sections II – IV of this testimony, there are serious uncertainties and risks with the Project as it is currently has been defined and studied, and the Project could harm Illinois customers. For these reasons, and the reasons discussed by Ms. Lapson (ComEd Ex. 2.0), RI's request for a CPCN to construct, operates, and maintain the Project is, at a minimum, premature. My concern is heightened in this regard because this Docket is likely to be the sole opportunity for state review of the Project. That does not mean that ComEd opposes the concept of the Project, opposes projects of a similar nature, or that any type of transmission expansion project is in general harmful. None of those things are true. The data simply does not allow critical questions about this Project to now be answered and the ICC should not move forward absent those answers.

Finally, RI's request for an order under Section 8-503 is both premature and inconsistent with RI's own testimony and the conditionality of RI's commitment to build the Project.

Q. Does this complete your direct testimony?

A. Yes.