The Northeastern RTO and merchant transmission

FERC had a busy couple of weeks in the transmission arena in July. On July 12th, it herded the transmission owners into the super-RTO corral, and on July 25th, it set the Neptune Regional Transmission System™ loose in that corral. Neptune proposes to establish a 4800MW merchant high voltage direct current (DC) network interconnecting Atlantic Canada with Nepool, NYPP, and PJM.[1] By Edward N Krapels, CFO of Atlantic Energy Partners, developer of Neptune.

By connecting generators in relatively remote areas with load in relatively congested urban areas, Neptune RTS™ also forms the backbone for the emerging Northeastern RTO, as the map nearby suggests.

FERC's order directed "Neptune to work with the Northeastern RTO to ensure that the RTO's tariff is designed in a manner that accommodates Neptune's financing needs." This is an important statement and is directed not just at Neptune RTS™, but also at the parties creating the Northeastern RTO. FERC's July 12th Northeastern RTO order noted that "our long term competitive goals are better served by RTO expansion plans that allow for third party participation as well as merchant projects outside the plan", and ordered PJM to revise its procedures "to include in its process that third parties may participate in constructing and owning new transmission facilities..."

The regulatory doors have swung open, therefore, to merchant transmission. Since (we believe) most merchant transmission projects will be aimed at urban areas, FERC's orders are most significant for urban areas and the companies that seek to serve them. Neptune RTS™ provides new options for meeting in-city power requirements.

Consider New York. While it may well be possible to shoe-horn one or two new 1000MW power plants into the city, and to re-power one or two existing plants, in the long run a new paradigm has to be found to provide for the continuous growth in the city's demand for power, not to mention the desire to remove from the city all sources of pollution that do not absolutely have to be there. In principle, new merchant transmission projects provide that new paradigm. Cities do not have to have big power plants within their limits, just as they do not have to make cars or steel or aluminum within the city. Assuming that reliability requirements can be satisfied, there are significant advantages to importing the power. In practice, in the competitive market, if the transmission solution is to be credible, it must not cost more than alternative ways to bring power and ancillary services or to continue to rely on existing generation assets, and it must meet the usual reliability criteria. New transmission projects also have to over-come fierce environmental opposition. In spite of numerous efforts to defuse the issue, the public's concern over fluctuating electro magnetic fields (EMF) is unabated, and thus it will remain extremely difficult to site new large-scale AC transmission systems, even over existing corridors. The Neptune RTS™ cuts through the environmental and reliability problems by proposing DC instead of AC lines, even for the relatively short New Jersey – New York City leg, and by putting the lines under the water, where their environmental impact will be short-lived and, by even the strictest standards, negligible. And, because it is DC, Neptune RTS™ not only meets reliability requirements, it makes significant contributions to system reliability.

Bright Lights - Big City

Can the Neptune RTS™ DC network proposal meet the economic challenge? That is a question that can be cut into three parts: the cost advantages of being located out-of-city, the price advantages of selling in-city, and the effects of providing the generator access to a portfolio of diverse and volatile markets and the load access to a portfolio of diverse and relatively low-cost energy sources. Regarding the urban premium, New York and Boston are now mixed gas - oil markets with lots of old and inefficient units, hence high energy market clearing prices. Over time, most of the oil-fired capacity will be phased out, and a few new CCGTs will be installed. But neither city is likely to be the home of surplus electricity generating capacity. Relatively tight capacity markets means enduring urban premiums (for energy and capacity) compared to surrounding suburban and rural areas.

Several years of location-based marginal pricing experience in PJM and New York Power Pool provide ample evidence of the existence of an urban price premium for electricity. During the period from June 1, 2000 to May 31, 2001, the average price in Zone J was more than US$20 higher than that of the PSE&G zone just across the Hudson River.

The cost advantages can be divided into several parts. Nova Scotia generators can access ex-tariff Scotian shelf gas, an advantage of up to US$10/MWh. New Brunswick has excess existing hydro, coal, orimulsion, and nuclear power in the summer, which will usually be cheaper than gas-fired power in Boston or New York City. Building a new CCGT in Nova Scotia, New Brunswick, or Maine is likely to be 15 to 20% cheaper than building in New York or Boston, and is unlikely to be levied a stiff interconnection charge, which is likely in the cities. Generators in the North are likely to have to buy fewer (if any) emissions credits, and to incur less (if any) summer de-rating. Gas prices in the city are likely to have an add-on if the local LDC has to build a lateral to the new plant. The cost of getting power from a new in-city plant to the load pocket is likely to include a significant transmission usage charge. These cost differences - the same dynamic that makes the price of the same brownstone in Jersey City and New York City be far apart - will be very substantial.

In addition, power sellers and traders are likely to place significant value in the portfolio benefits of access to Neptune RTS™. Instead of selling into a single market, as generators typically have to do, Neptune allows them to sell into Boston, New York, or southern Connecticut. In a similar vein, generators located in regulated areas (New Brunswick and Nova Scotia) can realize additional value for their facilities by selling volatility forward in the deregulated markets to which Neptune is connected.

When one stacks all of these cost and price advantages together, they add up to a considerable amount. Bean counters will protest that energy price differences alone will not support such regional differences. But electricity markets have a particular genius for disguising true costs and cost differences. The overall difference in providing power to an urban market is not just the US$35/MWh that a mythical CCGT in Manhattan could produce. It is also the US$12/MWh installed capacity payment (ICAP), the US$5/MWh ancillary services payment, the US$8/MWh transmission usage charge (TUC) to get the Hudson Valley's power to 49th Street, and so on.

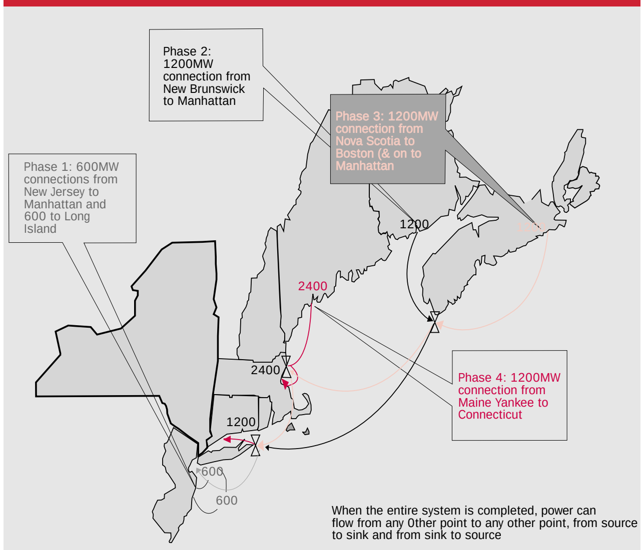
The Neptune RTS™ DC interconnection, as filed, delivers firm power to the heart of urban load pockets with a minimum of environmental disruption. Merchant Transmission, the Northeastern RTO, and the ITC How does a merchant project like Neptune RTS™ fit in the move towards a Northeastern RTO? Part of FERC's grand design is to conglomerate existing transmission facilities into an independent, for profit, transmission company (ITC). The underlying philosophy of that design makes sense: an ITC would not have the narrow regional and state planning horizons of traditional transmission providers. The history of electricity can be written in terms of development of transmission systems from the dam, to the town, to the county, to the state, and to the pool. Now comes the time for the super-RTO.

From a practical standpoint, the insistence on an ITC represents the next step in the destruction of traditional electric utilities. Companies who had already divested themselves of generation now have to sell their transmission assets - thus, T&D companies become "D" companies. Should they embrace merchant T or should they give up on T altogether?

As we have already seen, some utilities will use this last gasp of divestiture as an opportunity to further distance themselves from energy; others will use this as an opportunity to enhance the merchant side of their business. Some will add merchant transmission to their portfolios of competency, others will exit transmission altogether. Only time will tell which strategy is best for investors and ratepayers. The rise of the Northeastern ITC, however, seems assured. Within a few years, there will be an entity that owns or controls most of the existing poles and wires of the power sector. What does that imply for merchant transmission projects?

FERC has not yet ruled on whether the products of the ITC - transmission tariffs - will be one uniform number within the RTO (the so-called postage stamp), a small number of major tariffs (e.g., transmission service charges such as exist in current practice in NYPP and PJM), and/or a large number of market-determined tariffs, with prices effectively set by LBMP differences adjusted for line losses. The discussion among FERC Commissioners on July 25 showed they were anything but united on this topic. In the Northeast, over time, we assume FERC will continue to endorse the PJM model, with its emphasis on LBMP pricing, as being most appropriate to the political and business realities of the region, where enormous state-to-state differences in generator and transmission siting are likely to remain. The PJM model now has to be adapted more explicitly for merchant transmission

Chart 1 - Neptune route



investments. This will have to be done in terms of not only merchant transmission tariffs (which are relatively easy to accommodate in a LBMP system), but also system benefits and costs created by the investment.

Neptune asked FERC to confirm its right to seek system benefits payments if Neptune could prove they existed. While not guaranteeing any result, the FERC Order does exactly what Neptune asked FERC to do. The Order explicitly permits Neptune to seek compensation for system benefits it creates. The order goes on to reconfirm the right of Neptune RTS™, like any other Transmission Provider, to fully participate in the financial benefit of capacity it creates and the ancillary services it provides. Insofar as the DC system creates distinctive ways to provide ancillary services to the RTO (which its technology does allow shippers to do), these can be monetized in the various ancillary services markets. Insofar as Neptune permits increases in the transfer capacity of various existing lines, PJM and NYPP both have mechanisms (FTR's and TCC's) whereby those who create extra transfer capacity can monetize it. Insofar as Neptune allows existing transmission providers to avoid investments that otherwise would have to be made, incumbent transmission providers have to demonstrate to their ISO's that they have actively considered options available from merchant providers before the ISO's will approve their own plans. This approach was recognized in the New England Transmission Owners' RTO filing at the FERC last January. The New York ISO is already proceeding with a similar approach. It is fairly safe to assume that the new Northeast RTO will have to integrate this concept into its proposed planning process, given the language in FERC's Order discussing PJM's RTO proposal, in which it directed PJM to include merchants in its planning process.

A new business model is likely to emerge from this RTO-ITC-Neptune dialectic. It is likely to shake out in two phases. The next few years will be dedicated to setting up the ITC. The role of merchant transmission during this transition period is very clear: given the ITC's (and its constituents TP's) preoccupation with the transition, FERC's Neptune order gives the green light to merchant transmission entrepreneurs to identify and implement the needed transmission projects. Once the ITC and the Northeastern RTO are up-and-running, the role of merchant projects is less clear. First of all, utilities are not going to be required to sell their transmission assets to the ITC. But they will have to give up control over T, which makes ownership of these assets less than exciting.

Whether the ITC owns or merely controls existing T assets, it cannot be set up as a monopoly for new T assets because that would only repeat the mistake of the old IPP era. In its position as monopolist, the ITC would naturally resist purchasing the projects developed by merchants - the ITC would abuse the regulations. On the other hand, if it were forced to buy merchant projects, it is certain the merchants would abuse the regulations by building what is not needed.

Transmission providers should be aware that, in this model, the ITC is essentially a kind of bond fund of local transmission assets, collecting regulated transmission service charges which exist within a broader framework of (to use NYPP terminology) point-to-point transmission usage charges (TUC's) and the TCC's with which to hedge them. Those TUC's and TCC's will be the heart of the unregulated transmission business. There is certainly an argument to be made that the ITC should have an organ or two as well as a skeleton, that it should also be given a merchant arm (a brain? a heart? a spleen?), so that it can use its knowledge of the transmission grid to compete with dedicated merchant transmission developers to add value to the overall electric system. This would be an awkward fit – like grafting a trading function onto the FERC – but it is probably a bridge that will not have to be crossed for several years. Meanwhile, watch out for the transmission entrepreneurs.

Notes

1. ESAI Director Edward Krapels is also a Director and CFO of Atlantic Energy Partners LLC, the developer of Neptune RTSÔ. Thanks to Neptune partners Brian Chernak of Tompkins Research & Management Consulting, Kim Kenway of Curtis Thaxer Stevens Broder & Mi-coleau, and CEO Chuck Hewett of Cianbro.