Session 1: Generation Interconnection vs Transmission Planning, Why the Difference?

Question	Answer 1	Answer 2	Answer 3
Considering the reliability issues ERCOT has had recently during extreme weather events why are they considered to be the way to handle T&G planning?	ERCOT has a very fast generation interconnection process, but has room to improve its transmission planning process. The limited asynchronous interties with neighboring regions, which is as the heart of ERCOT's weather exposure, is a state policy choice. If the state wanted to add intertie capacity with neighboring regions, that would fall under what is generally referred to as "interregional transmission planning"	ERCOT has dealt with multiple challenges related to the extreme weather events that all work together to create the sum of the problem. No one issue caused all the problems. I will focus on Resource Adequacy in my response. One issue is proper weatherization, which affected many baseload and peaking plants during winter storm Uri. Wind and solar were also affected by icing. Assuming a perfect transmission system, lack of generation is addressed with better generator availability (i.e. weatherization and maintenance) and with increasing the number of new generators connecting (i.e. interconnection process speed, which is good). It must be noted that load in ERCOT is growing at a tremendous pace, meaning ERCOT is constantly looking for more generation to serve new load, not just to maintain light or stagnant load growth like most of the country. The other major component to resource adequacy is having sufficient transmission to connect the generation to load. I have seen reports of transmission constraints preventing renewable generation from serving load in a number of recent extreme weather events, indicating more transmission would reduce the impact of these events. One fundamental construct in ERCOT that is different from other regions is that all transmission, including the point of interconnection facilities, is funded by load. Therefore, the question of transmission construction is not a matter of who pays for it, but which process is used to design new transmission. As was discussed during the webinar, holistic transmission planning is superior to generation interconnection studies for efficient design of new transmission. Thus, to the extent generation is not able to serve load in extreme conditions, this needs to be addressed in ERCOT's transmisison planning process. Lack of interstate/interregional ties is another significant difference that was highlighted in winter storm Uri. The southern parts of SPP and MISO, which experienced similar generation shortages, had almost no load shedding because excess generation from east of MISO transferred across market seams almost entirely covered the shortfall.	
How do you account for benefit to load? What does it even mean? The Gi is triggering the projects and TPs have the system to serve existing load already.	A generation interconnection request may trigger the upgrade to a frequently constrained transmission line that increases the cost of serving load. In addition to facilitating the interconnection of new generation, the upgrade would also reduce the cost of serving load.	The most important contributions from new generation to load are the generator's capacity value (resource adequacy) and its competitive energy (cost of energy). The energy impact is traditionally measured through economic studies of a region. Renewables, in particular, have zero marginal cost energy and bid their energy into power markets for free (or even at a negative value during initial years of operation based on tax revenues associated with production). Thus, if load has access to a new renewable generator through adequate transmission, it will likely lower the overall cost of serving that load by displacing a thermal generator. A similar principle applies if a new baseload or peaking plant comes online that can produce energy for less than an existing plant. Resource adequacy benefit is defined in different ways in different regions. Some regions, such as PJM and NYISO, have markets where capacity is bid into the market and funded at a specific price by load. Regions like SPP simply have resource adequacy requirements that each load serving entity must meet. The responsible utility must contract with generators to ensure adequate capacity is available for peak-load periods. Adding new generation reduces the likelihood of generation shortfall events such as have been observed during extreme weather events in recent years. It is not always true that the existing system is always sufficient to serve load. The grid is constantly changing as a result of new load, retiring generation, aging infrastructure and many other things.	
For someone interconnecting Battery Storage, in ERCOT,does the rule still remains same for who (Ratepayers in ERCOT case?) pays for needed Transmission upgrades		Yes, in ERCOT load funds all transmission upgrades for large scale resources (including batteries).	
Question for EPE presenter: Solar at 40%: Is this 0% for winter and higher for summer? Does this consider availability of sun in winter vs summer?			Fuel based dispatch is meant to assign expected levels for different resources depending on resource type and how a specific ISO/RTO defines their loading conditions (light load, summer peak, winter). Yes, ISOs/RTOs would look at expected availability of a particular resource during a specific loading scenario in order to decide at what percentage this resource should be dispatched to.

What motivational incentives are effective for utilities to effectively manage interconnection studies?		This is not an exhaustive list, but motivational incentives can typically be broken into incentives and penalties. One of the main incentives that exists today is the opportunity to receive a return on investment/return on equity (ROI or ROE) on transmission upgrades built for generators (e.g. MISO's self-funding construct or being allowed to rate base upgrades after transmission credits are returned to customers). Because the interest rate is so high, however (often >10%), this can easily add 20-30% to the cost of the upgrades. Other incentives for utilities can include the reliability, environmental or energy cost benefits to load. However, some utilities who own a generation fleet will see new generators as undesirable competition to their own fleet rather than as as beneficial competition for load's benefit. Penalties for delayed study completion would likely look very similar to the FERC interconnection NOPR proposal to eliminate the Reasonable Efforts standard and to enforce a penalty for delayed studies. One challenge of this is that in RTO settings, the Transmission Provider (i.e. RTO) is responsible for timely completion of the study, but the Transmission Owner (i.e. utility) performs the majority of the work. More thought is needed to determine how to appropriately assess the penalty to the party causing the delay. Also, these proposed penalties do not address engineering, procurement and construction (EPC) work after the GIA is signed. Proposing penalties for failing to meet the EPC schedule is likely to be counterproductive, however, as utilities would simply include significant buffer in their proposed schedules for facility studies in order to avoid penalties. To try to address these issues, Aaron Vander Vorst described a new construct where the facility study would become an open bidding process. The winner would be selected by the Interconnection Customer based on the preferred cost and schedule. Utilities would be motivated to complete their studies on time to ensure they had the opportunity to build the upgrades and did not lose ownership of their transmission system. In the proposed competitive construct, the winner would face penalties for failing to meet their proposed schedule and cost, but would also receive a profit (such as a fixed percentage above bid price or a more reasonable rate of return) to make the risk worthwhile.	
Do RTOs have a size cap? RTO Size vs. Projection on the Horizon (In the queue) = does this suggest the RTO Size will grow in tandem with the queue? #Slide5 (edited)	There is no limitation on the size of an RTO. However, a larger RTO covering a more diverse set of states may be more difficult to govern.		
What impact could the Inflation Reduction Act of 2022 have on transmission projects and/or upgrades?	It will take some time for the impacts of the IRA to be unders	The Inflation Reduction Act has a number of provisions for a variety of financial benefits to both generation (including non-renewable generation) and transmission. It will likely accelerate construction of both new generation and transmission.	
How do you mitigate transmission ground overvoltage problems?			
how do NRIS and ERIS interact with ISO least-cost dispatch?	The least-cost, security-constrained dispatch of ISO market operations is not generally (fully) considered in NRIS and ERIS generation interconnection studies. This can trigger network upgrades on constraints that could be addressed more cost effectively through congestion managment.		
what about small signal stability/dynamic studies to track repeated oscillations during GI in local areas?	EMT modeling will become more important at higher localized levels of invertyer-based resource penetrations.	Dynamic stability studies are required as part of the interconnection process. Some Transmission Providers are beginning to implement EMT modeling as well.	Accurately observing transient stability events is highly dependent on the models used. Most ISO/RTOS perform dynamic simulations as part of the interconnection process, however the qulity of the models used and the type of analysis performed across regions can vary significantly and so does the ability to observe/replicate events
What about those projects which entities are forced to connect like those 80MW and below? How does this fall into your reform concept?		Generators which are connected under PURPA standards are still subject to the interconnection process. PURPA deals more with the monetary compensation for the generator's production and doesn't affect how the interconnection process is performed.	
The use of GET mitigations provides only momentary mitigations that do not address long term Issues . Can GETs be a long term solution for cost allocation?	Yes they can. Also note that reliability studies only evaluate "momentary" snap shots, such as a peak load hour with generation and transmission outages. GETs, for example, can temporarily or permanently shift flows ways from facilities that could be overloaded during the evaluated snap shots.		

Have Flexible Interconnections been considered to give a different interconnection option and to better prioritize infrastructure upgrades?			
FERC in a decades old order allowed for minimum interconnect, which allows underbuilding transmission and accepting curtailments. Why is this a new concept now?	That concept is ERIS. But some ERIS study criteria are more stringent than others.	Assuming you are referring to Order 2003 which established the standardized interconnection process, you are correct that this is not a new concept. Transmission Providers are generally expected to have consistent and transparent criteria dictating when an interconnection customer must fund an upgrade. Different transmission services (ERIS and NRIS, as well as NITS and PTP transmission service) have different study criteria. While the TSR process has an option to accept conditional service and not fund an upgrade, interconnection processes follow strict criteria without flexibility to the customer. The concern is that the strict study criteria should not assign transmission upgrades that are inconsistent with the type of service requested.	
Studies address both economic and reliability issues. How do selection of scenarios differ in traditional studies and how should they differ in future studies?	Yes they should. A more in-depth discussion can be found in this report: https://www.brattle.com/insights-events/publications/brattle-economists-identify-transmission-needs-and-discuss-solutions-to-improve-transmission-planning-in-a-new-report-coauthored-with-grid-strategies/	Today, economic studies are only performed in the transmission planning process, not in the interconnection process. Interconnection studies focus on reliability issues. However, the appropriate methodology for requiring upgrades in an interconnection study is unclear, as NERC reliability standard TPL-001-4 states that generators can be curtailed to mitigate reliability issues. Thus, the majority of the upgrades assigned in most interconnection processes may not be necessary according to TPL-001-4. This is why I personally believe that interconnection studies should replace power flow analysis with economic studies to demonstrate cost and benefit in the assignment of upgrades.	
For Aaron, how would regional generator interconnection studies in the West, which doesn't have widespread RTOs?		Thanks for the question. You can probably see from my proposal that I've spent more time working in RTO regions than non-RTO regions :). I'll take this opportunity to encourage RTO expansion into the west and other areas of the country to provide more efficient sharing and planning of the transmission system for the benefit of ratepayers. The reliability portion of planning studies in the west could mimic the transmission provider's local planning process, except for the addition of new generators entering the regional planning cluster study. These studies could primarily focus on delivering the portion of the generator that can be counted for capacity accreditation to load or could look at the full output of the plant with consideration for TPL curtailment allowances. The key purpose of economic studies is to determine the frequency, duration, and severity of transmission constraints throughout the year. This informs the planner regarding the total cost of the generation needed to serve load across a full year and how transmission constraints prevent the optimal generation dispatch to minimize cost to load. I do not know if this type of study is being performed in any context in the west today, such as by Order 1000 planning groups, individual utilities or research organizations. Where organized markets do not exist, the study may be more focused on SCED (security constrained economic dispatch) analysis and the associated curtailment for the new generator.	
Any additional considerations for cluster studies modifications for study areas whose queues far exceed the generation needs over the next decades?		It is reasonable to expect that in a future with high renewable penetration, the total nameplate amount of generation connected to the transmission system will likely be far greater than in the past when the system was comprised of dispatchable resources. This is not a new issue (today's system has generation in excess of peak load), but it will be more pronounced in a high renewables future. It should also be noted that excess generation increases competition, which lowers price for load, and regardless of service type, additional generation being online will increase the probability of the grid remaining secure under all operational conditions, including extreme events. Readiness requirements are important to ensure interconnection requests have made reasonable progress in other areas before entering the queue. Exclusive site control of the generating facility, transmission line, and point of interconnection station (where a new station is being built) continues to be one of the best readiness requirements, as it demonstrates real work and financial commitment by the interconnection customer. Other readiness requirements that demonstrate development progress and site suitability should also be considered. Dispatching generators in separate regional groupings can help to alleviate issues with total generation exceeding total load on a system. Most interconnection studies today are already completed with new generators being dispatched against existing generators. Queue rules need to be established so that older generators in the queue are also included in the dispatch after reaching a certain point of maturity.	
Aaron's proposal has gen's connection confirmed before the regional cluster study. What about risk that the connection would change after cluster study?		Requiring site control of the generator tie line and point of interconnection is an excellent way to reduce the likelihood of changes. The generator also must provide full security for those facilities, indicating a high degree of confidence by the developer in moving forward. However, it is reasonable to assume that there will still be limited instances in which a generator desires to change its connection later in the process. This could be the result of discovering sub-surface geological features, infrastructure such as pipelines or discovery of environmentally or culturally sensitive areas. Today's material modification process is an excellent construct and should be a part of any queue process, as it allows for reasonable changes as long as the change does not cause harm to another customer. It is important to remember that a minor modification by a project is less disruptive to an interconnection queue than a complete withdrawal and re-entry of the project.	

Re: Aaron's presentation: is the proposal (in part) to shift the cost of system upgrades from generation to the load? Won't it have adverse effects on rates?		There are a few things to consider in the larger picture. Fundamentally, yes, one of the ideas in the presentation did include load funding upgrades in the interconnection process. However, I am hesitant to immediately jump to the conclusion that it is either shifting upgrades or having an adverse effect on rates. The proposal includes three distinct studies, the local impact study, the regional study, and the advanced service study. The local impact study would assign all costs to the generator (though they may be reimbursed or offset through transmission credits, congestion hedging rights, or similar per existing tariffs). This study would identify ERIS or basic interconnection service upgrades. Per FERC's Order 2003, ERIS service (and also NRIS service, for that matter) does not guarantee that a generator will never experience congestion/curtailment, so it is reasonable to assume that not all observed constraints need to be mitigated. The main change in this study that some would say is "shifting upgrades to load" is that we have proposed to reduce the electrical distance at which upgrades are assigned. This increases the probability of upgrades producing meaningful congestion/curtailment benefit (said in Order 2003 terms, the upgrades get the most value for your dollar in terms of increasing "as available" injection to the grid). Whether these same constraints ultimately end up being funded by load would depend on the transmission planner's processes and rules. For example, a study to meet TPL-001-4 compliance should permit generation re-dispatch, thus a TPL-001-4 study should never identify an upgrade specific to a new generator, since that generator can be turned off ("Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings" from TPL-001-4 Table 1 bullet 'e'). Economic studies can be performed with the benefit to generation removed so that only the true value of a transmission upgrade to load is calculated (SPP does this). This also prevents "missed upgrades" from the interconnection process being assigned to load (unless it is actually beneficial for load to fund them, in which case the upgrades can be optimized along with other system needs). The regional study is the only study which would assign cost to load. This portion of the study would be focused on the economic benefit to both generation and load. Benefits to generation would be calculated separately as noted above. While we usually think of economic studies in terms of the cost of a transmission upgrade compared to the benefit created by the transmission upgrade, the reality is that the transmission itself doesn't CREATE the benefit to load, it ENABLES the beneft to load. Transmission by itself does not serve load. Transmission is fundamentally a	
If a project performed the Limited Local Impact Study, is there a timeline they need to proceed to the cluster or regional study for results to remain valid?		We have thought about that, but haven't decided what we think the best answer is. One option would be to require a study refresh on a certain time interval, such as every 1-3 years. This interval would probably be dependent on the frequency of other projects entering the regional process in a particular region. Another option would be to require a re-study if a different project in close electrical proximity entered the regional study. Criteria would need to be developed to determine an appropriate electrical proximity (e.g. project size, TDF or MW Impact on a nearby facility). To re-state the purpose of the local impact study, under our proposal the study would be designed to only capture local impacts. If constraint criteria is too far-reaching, projects will be too interdependent, and this individual process would not produce the proposed efficiency. Also, assuming power flow analysis continues to be the primary form of study for constraint identification, we must remember that power flow analysis is an inherently poor measure of congestion and curtailment, or in FERC language, "as available" injection. Thus, while our tendency as planners is to feel the need to protect the transmission system from any possible overload, the reality is that system and market operators have all the necessary tools at their disposal to direct proper curtailment of generation in order to maintain a reliable system. Thus, it would be important to not set the criteria for triggering a re-study too aggressively, but rather to let the market and system operators manage any minor system violations due to the combined impacts of multiple projects.	
For Aaron Could you please elaborate on local generation that are they dispatched at Max? What generation		We did not propose specific generation dispatch methodologies in our whitepaper. This is worth considering, but may be more appropriately determined by each transmission provider.	
If a Connect and Manage approach is adopted, what mechanism will ensure strategic wider works to increase			
In addition to other ERCOT question, given the very weak ERCOT interconnection to other areas, why was 300 MW of new gen in ERCOT creating issues in MISO?	Perhaps a misunderstanding. The 300 MW interconnection request was in North Dakota, not ERCOT.		
You are looking for an impact of 20% to identify any upgrades?		Yes, a 20% TDF was the value proposed in the whitepaper and presentation. This is a commonly used threshold in a number of regions, most notably SPP and MISO. However, other criteria also exist in those same regions that reach deeper into the system, as demonstrated on the North Dakota project example slide. Although we proposed 20%, this number (and all specific numbers) in our presentation should be looked at as recommendations that could be debated and changed. However, the more strict the criteria is, the more distant upgrades are assigned, and the more interdependency results in the queue. Our aim with 20% was to balance 1) requiring mitigation of constraints that would reasonably be expected to have a significant congestion/curtailment benefit with 2) preventing significant interdependency between projects that slows down queue processing.	

Why aren't dynamic line readings allowed in the interconnection process?	Transmission planners have a strong preference for traditional transmission solutions. There is also a bit of a misunderstanding of what these technologies can achieve to address energy and/or capacity interconnection needs. FERC has proposed to require that some of these technologies are considered as viable solutions to address the identified needs.		
What tools or technologies (software, hardware, or otherwise) would support faster and / or more cost effective interconnection?		Tools and technology are great, but we need more people with strong power systems engineering and programming skills first. Due to the rapid growth of the renewables industry and the high security risks involved in proceeding through the interconnection queue, the demand for engineers to perform and monitor interconnection studies has grown tremendously over the past decade, leaving many companies struggling to hire qualified candidates for open positions. In regard to efficient tools, I would point to PJM's interconnection study tools as a good model for how to efficiently perform studies. It is notable that PJM has one of the best track records of on-time feasibility and system-impact studies in the country despite studying projects individually. MISO uses a similar tool for NRIS evaluations. The basic premise of the tool involves taking a standard base case (i.e. not an intentionally stressed case) and using an algorithm to identify the top contributors to each monitored element/contingency pair. It then dispatches those generators to determine the mitigation requirement.	There is still a lot of improvement that can be achieved with automation studies. Certainly ISO/RTOs have some good tools for interconnection studies, however there is still room for improvement. Having a software provider like for example PowerGem manage the tools for ISO/RTOs is probably also a good idea since both ISO/RTOS as well as prospective market participants will end up using the same tools an should in theory get the same results (e.g. PJM GD tool developed by PowerGem)
Multi-value transmission planning is more easily achievable in an ISO/RTO. How would this work in the West, which doesn't have widespread ISO/RTO?	Multi-value planning for vertically integrated utilities is equivalent to integrated resource planning that co-optimizes generation and transmission plans. It evaluates how different transmission solutions affect all other system-wide costs.		
Where does equity fit into the priorities of proactive transmission planning?	Equity considerations would have to be considered as an added objective or constraint in the planning and permitting process		
Can Tx planning be done first to build corridors to unbottle transmission constraints? Then RFPs for GIs are issuedto use the corridor. Cost allocation on DFAX.	Yes. The SPP and MISO examples in Mr. Pfeifenberger's presentation illustrate the feasibilty and benefits of doing so.		
Could panel members give a definition of generation interconnection study and transmission planning study?		Generation interconnection studies are the studies required in the interconnection process to determine what upgrades must be made in order for the generator to connect to the grid. Transmission planning studies are regional studies that are not focused on any one generator, line, or load, but rather analyze the entire system to ensure that transmission upgrades are developed and built to preserve the overall reliability of the grid and/or to reduce the overall cost of serving load.	
Do GET mitigations satisfy TPL standards?	Yes. Though GETs may have different effectiveness for firm and non-firm transmission service needs.		
How does the industry address the enormous work load associated with interconnection studies? Many study engineers are overloaded and under high stress.	Integrating the various planning processes (similar to what SPP is planning to do with SCRIPT) will make a large difference. A "connect and manage" approach (as used in the UK and ERCOT) will also greatly simplify the generation interconnection study process and dramatically reduce work loads.	To add to Hannes' response, RTOs, utilities, consulting firms, independent power producers, and other segments of the industry should seek to contribute to building up a new generation of capable engineers. Things we can do include presenting to high school and college classes about the need for and importance of power systems engineers, programmers, civil engineers and other industry-specific degrees. This can also help to change the narrative about power systems being boring and unchanging. We should also implement internship programs and hire young engineers to give them a taste of the industry and to build up the workforce of the future, rather than exclusively focus our recruiting efforts on experienced engineers. Near term, transmission providers can benefit from sharing draft results with the interconnection customers as the studies are being performed. Interconnection customers are highly motivated to find optimal solutions to constraints identified in studies and will often contribute to the analysis by reviewing models and proposing alternative solutions. In a sense, interconnection customers can be viewed as a free consultant for the studies being performed. One last thought would be to consider AESO's (Alberta) approach to interconnection studies. The initial studies are not performed by AESO. Instead, interconnection customers must hire their own consultant to perform the studies in accordance with the AESO rules. While AESO staff still review the studies, this removes much of the administration and initial work on the studies from the AESO. Of note, AESO follows a "Connect and Manage" approach similar to ERCOT. This approach would likely not work in a Cluster Study setting with constraints being assigned between projects.	Couple of points to add/reinforce: Many ISOs/RTOs still only use a bench of a handfull of consulting firms to perform studies on their behalf. Expanding this list to a larger number of consulting organizations may speed up the process and allow for requests to be processed in a more efficient manner. Investing in automation and developing more robust algorithms for studies and interpretng results could help reduce workload from engineers. More transparency with regards to processess and study criteria as well as how to replicate ISO/RTO studies or having screening results from ISO/RTOS could result in less speculative projects holding up the queue and therefore reduce the amount of requests that need studying.

If deep upgrades are moved away from new connections, which entity ends up paying for costs under a more integrated framework?	All depends on the cost allocation that is implemented. To the extent deep network upgrades benefit loads, that share of costs could be allocated to loads. The rest of the costs could be allocated to interconnecting generators who	See earlier discussion under a question about shifting cost from load and increasing rates.	