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Requirements for a Redesigned Natural Gas Transmission and Distribution Module in the National Energy Modeling System

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Introduction

The Natural Gas Transmission Distribution Module (NGTDM) of the U.S. Energy Information Administration's (EIA) National Energy Modeling System (NEMS)[1] is undergoing a redesign. The purpose of this paper is to provide an overview of the existing module's function, some background information on the module, some of the problems with the existing module, and, most importantly, to outline the basic requirements for a new module. In some cases, a requirement is presented as a question, identifying particular areas for reviewers to address. However, reviewers are encouraged to comment on any of the requirements. While a design document will follow at a later date, some suggestions for possible approaches to handling the requirements are offered, in an effort to clarify the requirement and further the discussion.

NEMS is used to develop a U.S. domestic baseline energy projection and various side cases for the Annual Energy Outlook (AEO) progressively from one year to the next through 2040. Within NEMS, NGTDM represents the domestic natural gas market, connecting demand information from the demand and conversion modules of NEMS with the upstream supply information from the Oil and Gas Supply Module (OGSM), largely by representing a simplified pipeline delivery system. In the process, supply and demand are balanced, prices and flows are set throughout the system, and realized production is established, along with import and export volumes. The module also projects pipeline and storage capacity expansion. The current module includes a very limited representation of foreign supplies and demands of natural gas for the expressed purpose of projecting pipeline and liquefied natural gas (LNG) imports and exports. With the simultaneous development of a new Global Hydrocarbon Supply Model within the World Energy Projection System Plus system, this representation is likely to evolve during the design process. The redesigned NGTDM will ultimately interface with the new international model; although the specifics of the international model are not yet established, the NGTDM module design should accommodate this future interaction.

History/background

The Gas Analysis Modeling System (GAMS), developed over three years and used by EIA from 1983 to 1990, was the precursor to NGTDM. GAMS was largely developed to assess the potential impact of the deregulation of natural gas pricing at the wellhead and the movement away from pipeline companies' buying natural gas and delivering it to end-users toward only transporting (and, in some cases, storing) natural gas. GAMS included a representation of markets before restructuring and deregulation as well as after, including contracts with such provisions as take-or-pay arrangements, a bidding routine for new or recompeted contracts, and different categorizations and pricing of natural gas at the wellhead. GAMS used a linear program (LP) to solve and consisted of around 300 nodes and connecting arcs to represent known contract arrangements. Over time, supporting resources for the model dwindled, making it more difficult to manage, and—more importantly—markets evolved.

Thus, when NGTDM was developed in conjunction with NEMS, a simpler approach and network were employed. Interstate pipeline rate design, a popular area of analysis at the time (around 1990), received

[1] Documentation on most of the EIA models mentioned in this document is available on EIA's website at http://www.eia.gov/reports/index.cfm?t=Model%20Documentation.

some of the focus during the NGTDM design process. The concept of a spot market for natural gas was at the most early stages.

The initial NGTDM formulation involved a linear program that maximized consumer plus producer surplus minus transportation costs. Partially in response to problems that arose out of maintaining a large network in GAMS, NGTDM significantly limited the disaggregation of demands beyond the regions used within NEMS (Census divisions) and therefore consisted of a very simplified representation of the U.S. pipeline network. NGTDM distinguished between firm and interruptible demands, flows, and prices of pipeline services and determined pipeline and storage capacity builds in a separate seasonal model based on future demand and supplies that were set using the options of perfect foresight, adaptive expectations, or fixed expectations, a requirement of the initial NEMS.

Issues developed during NGTDM's design process and relatively early in its implementation process. During the design process, use of a linear objective function did not allow pipeline rates to vary with pipeline flows, limiting NGTDM design options. After implementation, the model was clearly over-optimizing and was not solving close to historical prices or quantities. In an attempt to better align the model with historical data, various measures, including, primarily, setting minimum flows, were put in place. This ultimately caused later problems as binding minimum flows within the LP structure resulted in shadow prices within the system that frequently did not reflect expectations of real world market behavior. Prices within the system were ultimately overwritten to better reflect expectations and allow the option of average nodal pricing. Marginal pricing at such aggregate regions tended to result in much higher prices than would be truly representative of a regional price. Additional problems arose from having a separate capacity planning representation, starting with the need to maintain consistency between the two representations. However, a bigger problem occurred when solving the current market year: the model was over-constrained by both setting minimum flows and fixing capacity builds. This led to frequent infeasibilities and positive backstop supplies.

As a result, a new heuristic solution algorithm was implemented in NGTDM; this algorithm replaced the annual market solver and the capacity planning routine. With the new algorithm in place, pipeline tariffs can be set as a function of volumes and, therefore, include a hurdle rate of sorts when flows exceed capacity, representing the capacity planning decision.[2] While the newer version of NGTDM (unlike the original version) separately represents a peak and off-peak season when setting current year flows, the firm/interruptible distinction was eliminated for network flows and prices, but was retained for delivered prices. The seasonal distinction was believed to be more important, while the firm/interruptible distinction was believed to add undue complexity. The regional representation was largely unchanged, but NGTDM was updated to allow flows in the current forecast year to shift from the previous year in response to relative prices, but not to represent a fully optimal result, thus aligning the model with history. At the time, interregional pipeline flows were believed to be driven by more than relative economics, particularly when dealing with such aggregate regions and time periods. The heuristic representation was much less restrictive than the LP because it allowed for nonlinear representations, and also for other changes to be implemented in the system in a more straight-forward manner, such as average nodal pricing.

[2] This effectively assumed that pipeline companies made the design with perfect foresight, theoretically some years earlier.

However, the key difficulties with the current NGTDM include:

- The impact of significant annual changes in the system (e.g., an Alaska pipeline to the Lower 48 states) is not automatic; rather, an analyst must add special code to the model and make a judgment as to the initial response.
- The manner in which two entities of very different sizes compete in the same market is questionable in that the larger entity initially has a significant advantage at the margin over the smaller entity, which is likely not the reality if a price advantage exists.
- The primary network flows are predetermined, and the current system does not readily allow for a primary flow reversal (as we are currently seeing on lines that historically fed into the Northeast).
- The spot price and hub system have evolved considerably since NGTDM was first designed and are not adequately reflected or accounted for in the model design.
- The influence of regulated pipeline tariffs on projected market flows is probably more than it should be.
- While code was added to allow supplies to be specified as either fixed or variable in response to price changes during the solution algorithm, this process is still not particularly clean or transparent.
- In general, NGTDM has been changed significantly since its original implementation to incorporate various patches and fixes, making the code difficult to change and debug.

In short, while the LP tended to over-optimize and did not align well with historical data, the heuristic approach is too tied to the previous projection year and does not handle significant shifts well (e.g., the introduction of large pipeline or LNG projects). It is possible that some of the key difficulties with the heuristic approach could be ameliorated by undertaking a major recoding of NGTDM. However, it is worthwhile to reconsider the approach, hence the impetus for this NGTDM redesign project.

Many modeling projects aim to resolve deficiencies found in existing models, address known issues, and respond to changing market conditions. The hope is that individually, and as a community, energy modelers are advancing the techniques used. While the basic LP approach has been used for a while, different modeling formulations can be employed to better capture anticipated market responses. In addition, some promising newer approaches are being employed that more readily accommodate nonlinear representations, agent-based approaches, and game theory. Some of these approaches will be examined in the course of this NGTDM redesign project.

Requirements

The primary goal of this NGTDM redesign project is to create a model that not only performs better, but is easier to update, evaluate, revise, and debug. Maintaining the model is expected to be the responsibility of one modeler working about half-time directly on the model. While the intention of this project is to reevaluate the model and recode it, there are a number of component parts (e.g., Canadian supply representation) that could largely be taken from the existing model, at least initially. Even so, the intention is to use a modular structure as much as possible in NGTDM to allow component pieces of the model to be more easily replaced with enhanced representations in the future. This modular structure should be reflected in both the coding of the model and in the model design. Additionally, the data handling process for inputs to the new module should be as streamlined as possible.

The following lists display the primary inputs/outputs to/from the current version of NGTDM from/to the other modules in NEMS, including its report writer. The new version of NGTDM would be expected, at a minimum, to maintain the ability to generate the same set of outputs from nearly the same set of inputs. Unless specified otherwise, the inputs/outputs listed represent annual values for each forecast year.

Primary inputs:

- Residential, commercial, industrial natural gas consumption by Census division and associated prices from previous iteration (industrial also by energy intensive and nonenergy intensive industries).
- Natural gas used in compressed natural gas (CNG) and liquefied natural gas (LNG) vehicles sold at retail and nonretail establishments by Census division
- CNG and LNG used in ships and trains by Census division
- Natural gas consumed by power generators by 17 regions in the peak and off-peak periods, with a breakout by customer class that depends on type of generator but is no longer valid. The Electricity Market Module divides consumption into six periods, so a different breakout could be used in NGTDM.
- Nonassociated dry natural gas supply curves by region [While the interface with OGSM currently includes 17 onshore and 3 offshore regions, OGSM can readily accommodate a different regional mix, with the caveat that the onshore regions should readily sum to the 6 or 7 reported onshore regions.]
- Associated-dissolved dry natural gas production volumes by region [These regions can/should be specified similarly to the nonassociated gas.]
- Representative world oil price
- Miscellaneous macroeconomic indicators used in setting returns on debt and equity and in estimating distributor tariffs

Primary outputs:

- Delivered prices for each of the demand categories and breakouts described above
- Natural gas consumed at lease operations and at natural gas processing plants
- Natural gas consumed as pipeline fuel
- Natural gas consumed at export liquefaction facilities and in association with the production of LNG for use in the transportation sector
- Nonassociated dry gas production and associated prices received by producers, which balance the market, by established supply region
- Natural gas pipeline and LNG import and export volumes and prices by border crossing
- Regional city gate prices
- Regional spot prices (not currently reported)
- Coal converted to synthetic natural gas by Census division
- Oil converted to natural gas by Census division
- Other supplemental supplies by Census division
- Interregional flows
- Interregional pipeline and storage capacities/builds

The newly coded model should also report on a variety of other variables, as well as regional and seasonal factors, to aid in evaluating intermediate results and debugging model code.

General

The driving market assumption for North America is that the market is competitive and that the final solution will reflect no arbitrage opportunities. Some adjustment on this assumption might need to be made when representing Mexico.

Questions:

- If the model is sufficiently detailed, is this assumption correct?
- To what degree might such market mechanisms as contracts invalidate this assumption?
- Are there any other factors that influence the market enough to consider incorporating?

While the model will initially be designed with a specific level of geographic and temporal detail, the desire is to provide enough flexibility in the code to allow for a relatively easy change in detail in the future as needed. It is expected that internally NGTDM will need to represent natural gas markets at a more detailed level of granularity (both geographic and temporal) than required by the NGTDM output requirements, and this may require synthesis of more-granular inputs than are provided from other NEMS modules.

The use of foresight for evaluating investment decision (whether perfect, imperfect, adaptive, or none at all) should be implemented with care, considering and addressing the convergence problems that led EIA to avoid the use of foresight in the current version of NGTDM. Regardless, decisions on infrastructure capacity should consider planning for abnormal weather and inherent uncertainties in future supply, demand, and prices (e.g., as they might impact investment risk and related costs).

Likewise, the model structure (i.e., whether it is an optimization model or a structural model, whether capacity decisions are treated separately from price/flow decisions) should support reliable convergence and efficient computational operation under a wide range of input assumptions.

Regional/seasonal detail

To better represent real world market dynamics, the model should be significantly more detailed in terms of regional representation than the current NGTDM, which contains 12 onshore Lower 48 nodes. The amount of detail incorporated will depend on data availability, as well as model manageability, balanced against the need to realistically represent market flows and prices. This internal geographic representation should be implemented as flexibly as possible, so that it can be expanded easily in the future as data become available or as market dynamics indicate. It is anticipated that some seasonal breakout will also be necessary to properly reflect market dynamics. The current model has a peak and off-peak period, as well as a representation of peak day volumes. This is considered to be the minimum necessary. It may be advantageous to align seasonal representation in the redesigned NGTDM with that used in the Electricity Market Module and the Global Hydrocarbon Supply Model. Again, this internal representation should be implemented as flexibly as possible, so that it can be easily changed if indicated by the inputs provided by other NEMS modules and/or to better reflect the dynamics of natural gas markets. EIA is not interested in generating as detailed a projection as possible for its own sake, but rather in representing as much detail internally as required to produce reasonable aggregate outputs that are used by other NEMS modules.

Historically, seasonal and annual variations in weather, including both extreme weather events and statistical fluctuations in temperature, have played a significant influence on both investment and operation of natural gas supply, demand, storage, and infrastructure. Historically, these weather fluctuations are measured, but in the NEMS projection period, “normal” weather is assumed throughout. How can the effects of “weather volatility” be incorporated in the new version of NGTDM in such a way that the effects of expected weather fluctuations in the projection years can be captured, even when the fluctuations themselves are not?

jbeNGTDM reports average regional prices back to NEMS. Depending on how the regions are defined, calculating such an average can be a non-trivial exercise. If the natural gas network were modeled with sufficient geographic granularity, and if the costs of supply were known, and if pipeline tariffs were well-understood, then the costs or marginal prices could be identified as a function of delivered volumes of gas for any node in the network. Conceptually, the supply curves from the various sources of supply could be projected to the demand centers with a markup. However, in a regional model such as NGTDM with unmodeled intra-regional gas infrastructure, the marginal costs could vary significantly within a region. The reported average regional price is thus an average of multiple, disparate marginal prices, which are dependent on unmodeled intra-regional infrastructure. The new model should develop an approach to resolve this ambiguity, potentially by backcasting and using historical data to derive regional price adjustments.

Questions:

- What level of detail (both geographic and temporal) is necessary to properly reflect the setting of aggregate prices in the network (e.g., at the average annual, Census division level)?
- Presuming the model solves for marginal prices, how can regional average (or hub) prices be derived?
- What are the implications for capturing bidirectional flows?
- What are the implications for pipeline and storage capacity builds?
- Can anything of value be projected about capacity builds in a more aggregated model?
- How important is getting capacity “right” to getting prices “right”?

Demand representation

While other NEMS modules provide projected consumption levels at the amount of detail described previously, NGTDM will need to synthesize (e.g., disaggregate) consumption levels at a more detailed level that remain consistent with the aggregated inputs. Alaska should still be modeled separately and subtracted out of the Pacific Census Division, in a manner consistent with the current NGTDM. While the current model uses fixed average historical shares to split out regions and seasons, this can potentially be enhanced by estimating state level (and potentially selected sub-state level if needed) consumption as a function of population and/or other demand determinants, then aggregating to the desired regional level, as well as potentially splitting out seasonal use for residential and commercial customers, at least, based on the percentage of fuel used for space heating.

While consumption should generally be received as an exogenous input by NGTDM, maintaining a simplified dynamic demand representation within NGTDM might dramatically improve computational performance with limited loss of quality.. Therefore, the model should be constructed with the ability to approximate the demand response provided by the NEMS demand modules. For example, the current NGTDM basically builds a curve off the last exogenous price/quantity pair and applies assumed elasticities. Ideally, these elasticities could be calibrated periodically through direct interrogation of the demand modules.

Supply representation

The new NGTDM should include a simplified representation of the supply response to price, as the full upstream model would require too much computational time to be solved each iteration. For the purposes of this project, the ability to significantly change the current interface between the NGTDM and the upstream model is limited, beyond a change in the regional representation. In general, supply should be represented using annual supply curves where volumes respond to price; however, some sources of supply might be set at fixed levels (e.g., associated natural gas) and not respond to changes in the natural gas price. The code and algorithm should accommodate either structure and should readily be switchable from one to the other. The current NGTDM specification of variable versus fixed supplies is not considered adequate for a revised module; as such, it is listed as a key difficulty in the "history/background" section. Seasonality on the supply side should also be represented; for example, the current NGTDM largely uses fixed historically based shares.

In theory, OGSM can aggregate expected production to whatever regions are necessary. A revised NGTDM should be flexible enough to easily accommodate changes in the geographic granularity of supply data provided to it by OGSM. It may be useful to start at a state level (or sub-state level where data are available) and aggregate to a regional level consistent with the demand representation.

Questions:

- Is it necessary to maintain some relation between the supply and demand regions (i.e., should production and consumption regions not overlap)? Can non-overlapping regions be constructed (synthesized) from whatever level of inputs is provided by the other NEMS modules?

Flows

It is anticipated that flows will largely, if not exclusively, be represented between neighboring regions at the seasonal level established for supply and demand (i.e., a pipeline running from the Gulf coast to New England would be captured in segments running between intervening regions).

Depending on the level of geographic and/or temporal aggregation, gas may flow in both directions between adjacent regions. This could be modeled by allowing flows in both directions along an arc or by asserting that the flows represent the net flow between regions. Most optimization algorithms would not choose to move gas in both directions simultaneously, so a secondary backflow, if used, might need to be specified based on analyst judgment or historical precedent; this, however, could lead to unintended secondary effects. Alternately, if the gas network is represented internally within NGTDM with enough geographic and temporal granularity, bidirectional flows may be minimized. At the least, the algorithm should support positive net flow reversal, as economics indicate, and the ability to set maximum flow levels consistent with available capacities.

The flow of gas should depend on the relative economics. The initial hypothesis is that gas flow will increase if there are arbitrage opportunities to be had (i.e., if the source node price plus variable charges is less than the destination node price) and decrease if the reverse is true. The algorithm selected will need to efficiently determine flows that allow this to occur until no further arbitrage opportunities exist. When there are alternate solutions, the algorithm should select the solution that minimizes year-to-year fluctuations in flows and prices. This can be accomplished, for instance, by including hurdle rates that must be exceeded economically before the model chooses to make changes. The physical interpretation of these hurdle rates is that they represent the residual effects of non-perfectly-competitive markets and/or the un-modeled real costs (e.g. transaction costs) of changing gas flows and/or the risk premium due to the inherent uncertainty in the values of future quantities (e.g., demand, prices), which is sometimes captured by a volatility measure.

In the current NGTDM, maximum flows can be set at something less than the physical capacity of the pipeline to account for the fact that consumption is based on normal weather and pipeline is reserved to handle more extreme weather. In the redesigned NGTDM, it may be effective to assign a “normal weather” capacity with the goal of better capturing when capacity might need to be added. At the same time, the current model assesses the ability of the pipeline and storage network to handle an estimated “peak month” flow. While the model assigns prices and flows for the peak and off-peak periods, it does not fully converge or set prices for the peak month, but rather just tracks flows.

Questions:

- Is there a compelling reason to model flows on a monthly level when NGTDM reports on an annual basis?
- Is it sufficient to have flows reflect net flows, or do the magnitudes of bidirectional flows need to be tracked separately?
- Should the variable charge (tariff) going one direction be the same going the other direction?
- What adjustments should be made to account for capacity built for abnormal weather and the fact that the NEMS consumption represents normal weather?

Capacity expansion/foresight

The new NGTDM should incorporate the concept of capacity expansion (new pipelines, storage, reversed-flow pipelines) endogenously. Unlike modeling physical flows or prices, modeling capacity investments inherently involves some concept of foresight. Even if current prices are used to determine the economic viability of new infrastructure projects, that is equivalent to assuming that prices will remain invariant through the payback period of the project, which is a strong statement of foresight.

In previous versions of NGTDM, a separate capacity planning module was run to determine capacity builds based on expected future consumption and production. This separate module was not only an extra burden to maintain, but also it could result in insufficient builds if expectations were underestimated. Relying on expected future values can result in convergence problems, depending on how the model is structured.

As a result, the current NGTDM has replaced the capacity planning module with tariff curves that can be extended beyond the existing capacity level. The tariff rate for the existing capacity reflects variable charges, whereas the tariff beyond the existing capacity is intended to reflect something of a hurdle rate for the capacity to be built if needed and is intended to include the reservation fee, at a minimum. The capacity is built when still desired/needed at the higher rate and is built in the model year in which it is needed (although the inherent assumption is that it was planned to be built ahead of time with perfect foresight). This approach avoids the previous convergence problems while still acknowledging that capacity expansion decisions are made with some understanding of future conditions.

Another approach might be to decide to add capacity once the utilization on a line exceeds some maximum level. The underlying assumption for both approaches is that if the demand for the capacity is there in a given projection year, it will still be there for some amount of time in the future. This assumption would not hold if regional demand decreases, obviously.

Questions:

- Many models optimize across time and essentially assume perfect foresight. Does this result in a reasonable result or is this over-optimizing? The rest of NEMS solves one year at a time, for the most part, but the Refinery Module and Electricity Market Module incorporate some look-ahead elements.
- Is the approach used in the current version of NGTDM, as described here, sufficient for a revised module, or could it lead to problems under any future conceivable conditions?

Pipeline tariffs

The model will need to separately establish variable charges and reservation fees. Variable rates will be used in establishing flows and setting hub spot prices. The intent is to set delivered prices to electric generators off the hub prices, and potentially industrial prices as well. Some of these consumers pay reservation fees as well. Consumers who purchase gas from the equivalent of a local distribution company pay rates that include reservation fees.

NGTDM calculates regulated fixed and variable rates based on a revenue requirement calculation. The current model does not use the calculated variable rates, but sets node differentials based on observed average differentials between historical spot prices. While the variable rate calculations should be re-examined to better align them with historical observations, the new model should at least be able to replicate the performance of the existing model. Ideally, the differentials should be normalized to normal weather (i.e., the baseline differentials should reflect expected differentials if weather had been normal) and set to rise with increased pipeline utilization. At a minimum, the variable rate should cover the pipeline fuel charges. Backcasting historical basis differentials using the new model would seemingly also serve as a means for evaluating the performance of any new algorithm.

It is not clear that calculating and applying a regulated reservation fee, as is done in the current model, necessarily results in more accurate prices. The current model ends up benchmarking the city gate prices, which are set using these reservation fees, to historical values. The idea is to base the reservation fee in the model on historically observed city gate price differences minus calculated variable charges. This approach involves some of the same concerns as setting the variable charges based on spot price differentials, particularly the difficulty of factoring out the effects of extreme weather on historical prices. In addition, the reservation fees might change over time or with the addition of new capacity, and policy changes in how regulated reservation rates are set might need to be implemented.

Questions:

- How could the model be validated by looking at posted rates versus historical differentials? What level of effort would this require?
- How often does the variable charge actually exceed the pipeline fuel charge (i.e., is the pipeline fuel charge a reasonable enough proxy)?
- How important or plausible is it to capture how rates might change over time, such as rate changes resulting from depreciation of pipeline? Should the model continue to estimate revenue requirements and set reservation fees based on a regulated rate calculation?
- How important is it to include assumptions about how costs of adding capacity might change over time?

Delivered prices

At a minimum, the new model should set delivered prices as they are set in the current model, that is, by adding a historically based markup to the regional hub or city gate price, depending on the sector.

- Should the model attempt to represent gas flows and prices for firm versus interruptible customers explicitly, or is it reasonable to move gas based on variable rates, setting regional prices for interruptible customers based on spot prices, and then calculate fixed (or reservation) rates to add to these to generate the equivalent of a regional city gate price for firm customers?
- How might rates to electric generators reflect the potential need for them to purchase more firm service (and presumably pay higher rates) if they take on a greater market share?

Alaska

For the most part, Alaska is handled as a completely separate model, and it is not a high priority to include an endogenous representation of Alaska for the initial version of the new NGTDM. However, the new NGTDM should be able to better handle large discrete changes in supply or demand (e.g., a pipeline built from Alaska to the Lower 48 states or the construction of a large LNG export facility).

Canada

The current model divides Canada into east and west regions, with seven border crossings. While the desire is to model Canada in the same manner as any other region, data limitations drive the need for special handling within the current NGTDM. If resources permit, an improved representation of Canada should be included in the redesign. However, at a minimum, the existing module should be coded to allow for a more ready replacement of an enhanced version. In particular, , the interface/overlap with the Global Hydrocarbon Supply Model will be a consideration for how Canada should ultimately be represented.

Questions:

- Is Canada just another region in North America or are there any special considerations to be included?
- How should Canadian natural gas supply be modeled? Are there clues from OGSM that can inform Canadian supply response within NGTDM?

Mexico

While the current model basically represents imports and exports at the U.S.-Mexico border, largely based on assumption, the new model should ideally represent the infrastructure within Mexico. The limitations on pipeline capacity running from the U.S. border to Mexico's demand centers, are potentially important in projecting future levels of imports and exports between the two countries. Mexico presents similar data availability issues as Canada, but also presents a question as to whether it is reasonable to assume a competitive market going forward, like that in the United States, or to impose some limitations.

Questions:

- To what degree is it reasonable to represent Mexico as a competitive market going forward?

LNG imports/exports

The Global Hydrocarbon Supply Model project will be integral in deciding how to represent LNG imports and, more importantly, exports in the new NGTDM. The running assumption is that there will be supply and demand curves for imports and exports, respectively, similar to those used in the current model. The new global model is assumed to provide a means for better assessing world market interactions with the United States. A primary issue for LNG exports is the discrete nature of capacity builds and the potential of nonconvergence across NEMS cycles. As much as possible, this should be considered in the new NGTDM design. As with the current model, planned capacity builds should be incorporated, as well as a means for endogenously setting liquefaction and regasification utilization based on market factors (i.e., not just assuming a utilization rate).

Questions:

- How should the possibility of LNG imports/exports from Canada and/or Mexico from/to the rest of the world be handled in NGTDM? Is it sufficient to treat these as similar regions in North America or are any special considerations (e.g., regulatory environment) needed?

Benchmarking

As practical, necessary, and reasonable (i.e., accounting for abnormal weather), the model should be benchmarked to history. While the ideal result is that the model reproduces history reasonably well, the reality is that this can require some adjustment. The same can be said for aligning model results to results from the Short-Term Energy Outlook (STEO). Mechanisms should be put in place in the model to benchmark to key STEO results as is done in the current model.