Independent Statistics & Analysis
U.S. Energy Information Administration

Natural Gas Transmission and Distribution Module Component Design Report

August 2015

Independent Statistics & Analysis
www.eia.gov

U.S. Department of Energy
Washington, DC 20585

This report was prepared by the U.S. Energy Information Administration (EIA), the statistical and analytical agency within the U.S. Department of Energy. By law, EIA's data, analyses, and forecasts are independent of approval by any other officer or employee of the United States Government. The views in this report therefore should not be construed as representing those of the U.S. Department of Energy or other federal agencies.

Table of Contents

Background 1
General Approach 2
Benchmarking 4
History 6
Short-Term Energy Outlook (STEO) 6
Demand 6
State level/monthly consumption 6
Alaska/Hawaii 7
Demand curves 7
Discrepancy 8
Lease and Plant Fuel 8
Pipeline fuel usage 9
Imports and Exports 11
Supply 12
Fixed supplies 12
Price responsive supplies 12
Storage 14
Pipeline Tariffs 15
Variable Tariff Curves 16
Pipeline Expansion 16
Pricing Submodule 17
Building a hierarchical acyclic network 17
Flowing volumes down through the network 18
Flowing fixed charges up through the network 19
Setting delivered prices 20
Other outputs to NEMS 21

Background

The Natural Gas Transmission and Distribution Module (NGTDM) is a module of EIA's National Energy Modeling System (NEMS) which balances domestic natural gas supply and demand, including imports and exports, and in the process projects prices throughout the representative pipeline system, as well as realized production, regional flows, and pipeline capacity additions. The NGTDM was initially developed in 1991 as a linear program (LP), but was revised significantly in 1994 in response to shortcomings in the original approach. While numerous updates/modifications have been made since then, some subsequent changes in market dynamics are not easily captured with the existing methodology (e.g. reverse flow on major pipeline corridors), prompting a redesign.

The primary requirements of the redesigned NGTDM are to 1) project delivered, wellhead, import, and export prices given delivered volumes and a set of regional supply curves, and 2) balance the natural gas market and establish production, imports, and exports, as well as lease, plant, and pipeline fuel, and supplemental supplies. A secondary requirement is to project interregional flows and pipeline capacity. In addition the model must align well with history while also being able capture likely future market behavior and be relatively easy to maintain, update, and modify. More details on the model requirements can be found in the August 2014 EIA document, *Requirements for a Redesigned Natural Gas Transmission and Distribution Model in the National Energy Modeling System*.
Before settling on a model design, various existing and retired model approaches for representing natural gas markets were reviewed to the extent possible and described in the September 2014 Leidos report, *Review of Natural Gas Models In Support of U.S. Energy Information Administration Natural Gas Transmission and Distribution (NGTDM) Redesign Effort*. The models reviewed included both domestic and international models with varying levels of regional and temporal granularity. The models had varying mathematical approaches as well as differences in their primary purpose (e.g. some models focused on individual pipeline planning issues). In addition, a workshop was held with experienced natural gas market modelers to gather lessons learned, reasons for certain approaches taken, and general advice to support the NGTDM redesign. Finally, a simplified network model was built to test different approaches and model structures to inform the design process.

The approaches used by other modelers largely fall into three classes, a linear (or nonlinear) program, a mixed-complementarity formulation, and an agent-based approach. After some review and testing, EIA concluded that mixed-complementarity and agent-based models are useful when modeling markets without perfect competition, but in the case of perfect competition these formulations yield the same solution as linear (or nonlinear) programs which maximize social welfare. Furthermore, EIA concluded that the United States natural gas market is a competitive market and could be effectively modeled with the assumption of perfect competition.[1] Therefore, no reason was seen to adopt a mixed-complementarity or agent-based approach over a nonlinear program and that a nonlinear program would be easier to develop and maintain. Thus the methodology proposed for the redesigned NGTDM is basically the same approach taken by EIA in 1991, and that there are some reasonable approaches that one can take to appropriately address some of the issues that arose previously.

[1] In some cases the existence of long-term contracts could result in markets operating in a less than optimal manner, which could require some special handling (e.g., minimum flows) to properly reflect market dynamics in the first years of the projection period. Most notably long-term contracts are resulting in gas flows into the Northeast when market prices seem to indicate that gas should be flowing in the opposite direction.

The 1991 LP maximized consumer plus producer surplus minus transportation costs, and balanced supply and demand throughout a simplified pipeline network (12 domestic nodes). This basic approach is being proposed for the new NGTDM. However, the intent is to address the shortcomings in the original approach within the new design and to also extract some of the features of the current model when helpful. The primary problem with the 1991 version was that it did a very poor job aligning with historical patterns. At the time, the general response was to add constraints, which ultimately contributed to frequent infeasible solutions. The current version of the model addressed this issue by setting flows in the current forecast year based in part on the flows from the previous forecast year (or the last historical year for the first forecast year), allowing only relatively small incremental changes to the year-to-year flow patterns. This generally worked, but the approach was problematic if circumstances or an event would be expected to cause a more major change in regional flows (e.g., if a large volume pipeline were to be built from Alaska to the Lower 48). Different approaches were tried to address this problem, but none were entirely satisfactory.

The basic approach to addressing the issues which arose with the 1991 LP is to 1) represent pricing at a more disaggregate level, where the marginal price for the region/period is more likely to align more closely with the historical average price for the region/period, 2) set pipeline rates based on historical price differentials (i.e., state-to-state differences in spot and citygate prices) rather than on regulated rates, 3) set flows based on variable charges, accounting for reservation fees separately, and 4) allow pipeline capacity to increase in the current solution year if volumes and prices warrant rather than in a planning model for a future year, as was done in the 1991 version.

The model development process was driven by the desire to determine approaches to best reflect the primary factors which are believed to drive market behaviors now and into the future, balanced with the availability of data and resources to implement, maintain, and run the model within NEMS. The fact that the model is intended to produce annual regional results through 2040 and is not a short-term model played a role as well. The basic philosophy is to represent the market at a level of detail beyond what is required. This will allow the model to use marginal pricing to set prices at a more detailed level and then aggregate or average, as appropriate, these results to the desired level of detail. This strategy is believed to yield better results than simply modeling at a more aggregate level.

The redesign extends beyond the model methodology and will involve making improvements in the model code and input and output data processing routines. The goal is to produce model code and supporting programs that will be easier to maintain, debug, update, enhance, and use for different purposes, as well as for a new person to understand. Over time, programs that are changed regularly, particularly by multiple people, have a tendency to deteriorate. So, the goal is also to incorporate a structure that encourages continued good coding practices as much as possible. A separate software design process was recently initiated toward this goal and is beyond the scope of this paper. However, reviewers are encouraged to offer any suggestions related to software design.

General Approach

The core of the new NGTDM will be a nonlinear optimizer (NLP) that will balance natural gas supply and demand by maximizing consumer plus producer surplus minus variable transport costs, while insuring mass balance at each node. More specifically, it is anticipated that the model will be specified by a quadratic objective function with linear constraints (i.e., a quadratic program). Supply and demand elements will be represented by price responsive curves or as fixed volumes, with the code accommodating the user to select one or the other. Fixed volumes might be set exogenously, by other NEMS modules, or endogenously outside of the NLP. Obviously it is necessary that a reasonable portion is specified as curves, or the model will be limited in its ability to balance the market. The representative network will contain a market hub in approximately each state, as well as limited international nodes, and will solve for at least three seasons a year, with an additional solution generated for a peak period[2] to project pipeline capacity expansion. An explanation of the choices made follows.

- *A nonlinear approach was selected over a linear program as it was believed to not add an appreciable amount of solution time for a quadratic nonlinear objective function with linear constraints and to generally be more straightforward to specify and implement and to limit the potential of knife-edge solutions.*

- *The regional breakout by state was selected because of the ready availability of data by state and the belief that it provides sufficient detail to fulfill the model requirements, even though it is recognized that some potentially important detail might be missed (e.g., in not breaking out North and South California).*[3] *In some cases domestic production will be represented at a substate level.*

- *In theory, given the data, the model could solve on a monthly basis. The reality is that prices actually can vary quite a bit from day-to-day, which not even a monthly model can truly capture. The current assumption is that three seasons will allow the model to capture some of the disparities in prices and flows by season, but not add too much additional processing time. However, once the model is in place, it will be tested to assess the cost/benefit of running the model for each month, by evaluating the difference in execution time and in model results compared to running with three seasons.*

The primary output from the NLP will be the production and consumption volumes (including imports and exports), as well as net node-to-node flows, which balance supply and demand.[4] The solution will reflect the marginal price of supplying the resulting volumes, in particular because fixed charges, such as pipeline reservation fees, are not reflected in the solution. Therefore, a secondary component of the module will be the Pricing Submodule, where reservation fees and other potential adjustments will be added as appropriate in deriving citygate and then delivered prices. The direction of flows resulting from the NLP solution will be used to build a hierarchical network, which will in turn be used to trace prices through the system, adding reservation fees in the process. Regional delivered prices will be set by adding an estimated markup, generally a distributor tariff, to either the quantity-weighted average regional citygate or hub price or a combination thereof.

---

[2] It might be necessary to also run the model for a summer peak month to evaluate the potential need for pipeline expansion in places like Florida, unless a more targeted approach can be devised for selected regions/states.

[3] If data issues can be resolved this is a likely future enhancement to the model and will be considered during the coding process, particularly if hub prices within a state show disparate historical trends.

[4] If no demand curves are employed, consumption will largely be an input to the NLP, with the exception of lease, plant, and pipeline fuel use; production will largely be used to balance the market via supply curves from OGSM; and the international representation will vary.

Once at the beginning of each forecast year, or potentially in each NEMS iteration, the NLP will be run for a peak demand period to estimate pipeline capacity additions. Instead of looking ahead at anticipated supply and demand, as is done in other NEMS modules, the assumption in the NGTDM is that, while pipeline capacity will effectively be built instantaneously, the decision to build was theoretically made beforehand with perfect foresight. The capability to expand will be added into the tariff supply curves by allowing flow to exceed current capacity, and expansion to occur, at a hurdle rate should the demand be sufficient.   To capture expansion to satisfy summer peaks, such as into Florida, it probably will be necessary to evaluate a winter and summer peak. Consumption levels will be increased, as appropriate, to represent safety margins built in to accommodate more severe weather.

A general flow diagram is provided in Figure 1, with a more detailed description of the components and the sequencing provided below.

Benchmarking

An important aspect of the model will be aligning the results with historical patterns. When a model, or aspects of a model, are specified using econometrically estimated equations, alignment to history is reasonably automatic, particularly if lag terms are included. However, the central routine of the NGTDM is not econometrically based, and econometrically based models might not be an adequate representation for a longer-term forecast horizon. A pure process model, which attempts to represent the decision making done by an industry, can do a relatively poor job of backtesting, such as when the behavior of multiple players are optimized as one or generally when decisions are aggregated (e.g., regionally or over time periods). In addition, in cases where history is driven by weather and the forecast assumption is to assume normal weather, it is important, as appropriate, to remove weather effects from the targeted historical data.

The current NGTDM balancing routine was largely based on using lagged values and modeling the degree to which the values from the previous forecast year would change in the current forecast year. This approach tied the model results in the basic balancing routine (e.g., flows) to history from the start. However, the citygate prices projected by the model when run during the historical years did not align well with history and benchmark factors were set and held constant to force alignment. One potential reason for this involves how the pipeline tariffs are set, largely based on a theoretical regulated rate calculation. The approach for the new NGTDM is to base the pipeline tariff curves (specified as a function of pipeline utilization rates) on historically observed differentials between state-to-state spot and citygate prices. Other similar approaches will be taken in each area to align model parameters to history (accounting for weather effects as possible) to benchmark the model to history.

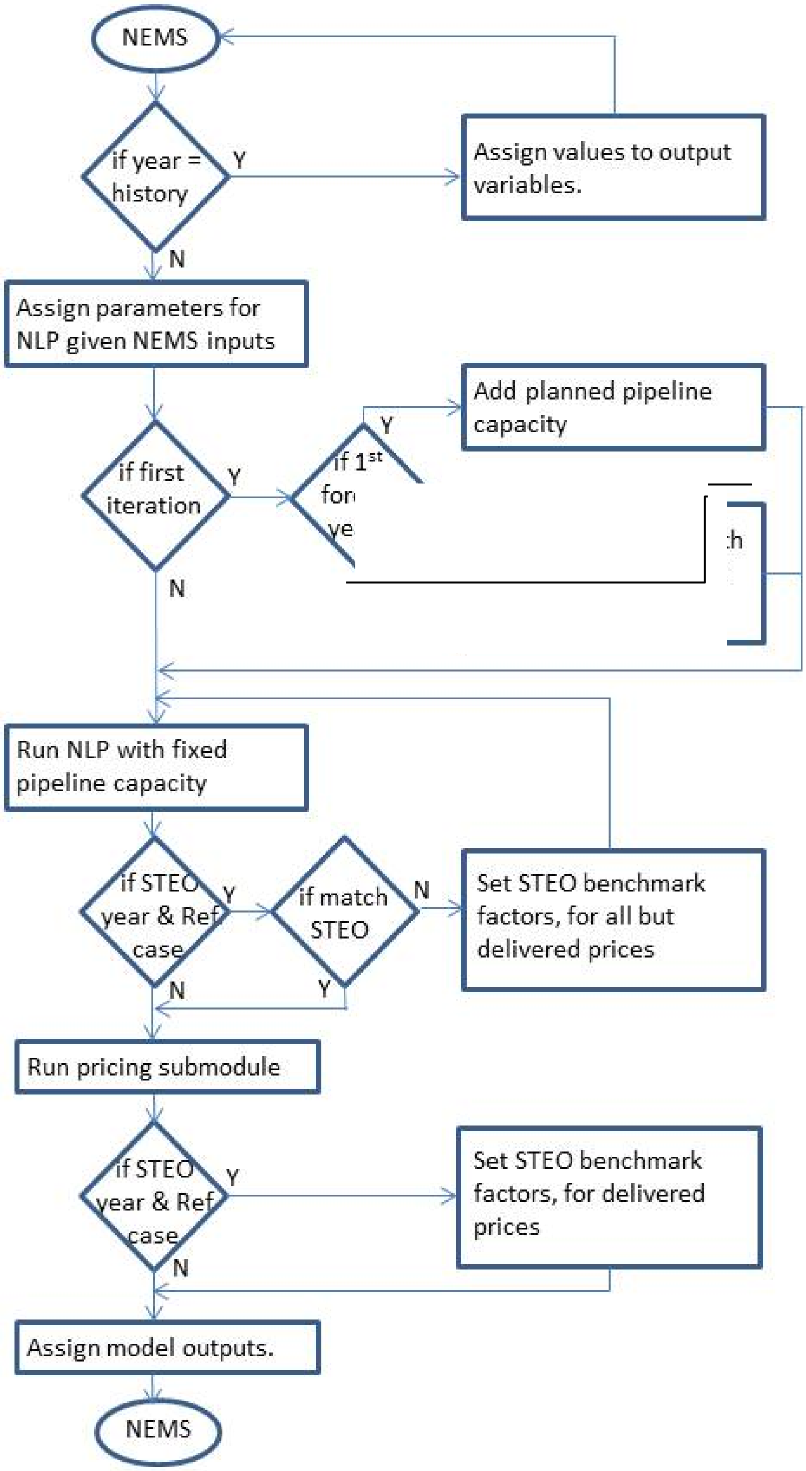

Figure 1. NGTDM Flow Diagram

History

In general it is not necessary to run a NEMS submodule for years where historical data are available to fill the output variables. However, the NGTDM will likely be run during at least some of the historical years in a test mode to determine how well it is aligning with history. In the current model, the key historical benchmark factor that is held constant throughout the forecast is the factor to align with historical citygate prices, which should not be necessary given the specification used for assigning pipeline tariffs in the redesign. The current model is also run in the historical years to fill in some missing data and set historically based parameters, which is also not a requirement for the new design. Most of these sorts of calculations will be done in a preprocessing routine.

Short-Term Energy Outlook (STEO)

A basic requirement of the NGTDM is that it produce model results during the STEO years (the first two or three years after the last historical year) which are within about 2% of the STEO results from a selected publication. Most of the STEO projections are national numbers, except for regional delivered prices to residential, commercial, and industrial customers. In the current NGTDM and the new NGTDM this will be handled in a similar manner with some different approaches used in different areas, as presented separately below. However, a few issues related to STEO benchmarking are overarching: 1) the NLP will be executed multiple times to achieve convergence with STEO in these years, as the STEO benchmark factors are interdependent, 2) the STEO benchmark factors will be phased out after the STEO years over as many years as specified by the user, 3) the benchmark factors will be captured during a NEMS Reference case run and read during side case runs to allow the model to vary consistently with the side case, 4) some benchmark factors will be multiplicative (based on 1.0) and others additive (based on 0.0), and 5) total supply is benchmarked by setting total disposition (consumption plus net imports minus net storage withdrawals) to STEO values so that production necessarily will be consistent as well.

Demand

Projected annual sectoral consumption levels each forecast year will be provided through the NEMS system for the 9 Census Divisions, with the exception of the electric sector which currently provides consumption for 18 regions and 2 seasons, even though it solves internally for 17 regions and 3 seasons.[5] Industrial consumption is further broken out into energy-intensive and non-energy-intensive categories. Vehicle fuel consumption has an even more extensive breakout into various transportation modes and classes, which is only really significant when setting the corresponding prices and will be discussed further in relation to distributor tariffs.

State level/monthly consumption

In order to support the need for representing consumption/demand at a more detailed level, monthly consumption will be estimated at the NGTDM regional level (e.g., state or sub-state) for each sector or sector grouping. These estimates will be used as a basis for sharing out the annual regional consumption levels from NEMS to the NGTDM region/month. In the case of electric generators,

[5] Electric consumption is further broken out into three category types (firm, interruptible, and competitive), which currently receive the same natural gas price, and therefore are no longer useful and can be collapsed together. It

consumption at the three season level will be shared out. Until the data are analyzed the specific equations that will be used cannot be set for certain, but the initial expected approach follows. Residential, commercial, and industrial consumption by state/month will be estimated separately as a function of annual population and monthly heating degree days (HDD). It is anticipated that cooling degree days will need to be included when estimating gas consumed by electric generators. The NEMS Electricity Market Module might eventually provide additional information for which regional projections to be disaggregated to state levels. For the forecast, heating degree days and cooling degree days will be set to an historical average level (probably 20 years), while annual population will be set to the census forecast. In theory, if consumption is fixed in the NLP, the state/monthly volumes can be aggregated over sectors and represented in the NLP as total delivered volumes. However, the sector level consumption by state/month will also be used in establishing quantity weights for setting average regional citygate prices.

Alaska/Hawaii

Since Alaska and Hawaii are not currently connected to Canada or to the Lower 48 states by pipeline, they are handled differently in the current NGTDM. The basic approach is expected to be duplicated in the new model. The NGTDM contains a simple model that estimates natural gas consumption in Alaska by sector (excluding electric generators, since it is provided from NEMS), and the associated lease, plant, and pipeline fuel. These volumes are subtracted from the Pacific Census Division consumption volumes to arrive at a level for California, Washington, Oregon, and Hawaii. In theory, the volumes for Hawaii should be separated out in a similar manner, but have traditionally been too small to bother. A small volume of synthetic natural gas is produced in Hawaii, and fixed at historical levels in the current NGTDM, to supply Hawaii. There are currently plans to import LNG into Hawaii, so the accounting will need to be adjusted in the new NGTDM to accommodate this possibility, but the basic approach will be similar. Consumption in Hawaii is assumed to equal synthetic production plus imports, whereas production in Alaska is assumed to equal consumption plus exports.

Although it has become less of a possibility, the current model includes an algorithm to decide whether to build a pipeline from Alaska's North Slope to the Lower 48 states, and adds lease, plant, and pipeline fuel consumption as appropriate should this occur. The option of building a new facility to export LNG from the North Slope out of Alaska is also part of the current model and similarly includes the appropriate associated consumption and production. The algorithms for representing both of these projects, and their interrelationship, should be transferred to the new model. The one element lacking in the existing model that should eventually be incorporated into the new model is the potential impact on delivered natural gas volumes if additional communities in Alaska have access to North Slope gas as a result of these projects. Also, it would be advisable to coordinate with the NEMS demand modules on how this might impact total Pacific Census Division consumption.

Demand curves

Through the iterative process used in NEMS, the separate demand modules In NEMS act as demand curves, responding to changes in natural gas prices from one NEMS iteration to the next. The NGTDM does not require demand curves, but they could be useful to include as an option. Generally demand curves within a NEMS supply module serve to speed overall convergence. However, the representation must push the model toward a result that is consistent with the final consumption levels in NEMS, or a discrepancy will result. Given that demand in the NGTDM is not represented at a Census Division level, this would theoretically require scaling the state/month level demand curves in a region to align at the

Census Division level and iteratively calling the NLP until the disaggregate curves average/aggregate to the regional curve, but this is probably not worth the extra computing time. Also, there is some potential misalignment because the demand curves would need to be based on the state hub price, not a delivered price, since the NLP does not solve for delivered prices. While the use of demand curves might be helpful for some model testing, they are likely not to be used when the model is running in an integrated NEMS mode.

Discrepancy

For various reasons, historical data contains a discrepancy between total supply and disposition. This is also referred to as a balancing item. These discrepancies occur nationally, in each state, and in each month. In order to better align the model with history, the current model and the new design will include a projected value for discrepancy for each region represented and month. These levels are set at an average over an historical period and held constant through the projection period. The only complication is that EIA only publishes a balancing item for each state annually and a monthly balancing item for the whole United States. So, the routine which fills in missing historical values will need to generate state/monthly discrepancy values that are consistent with the published numbers. In the NLP, discrepancy is added into the total consumption at each node, whether it is positive or negative. In the STEO years, the difference between the national level STEO discrepancy and the national level NGTDM discrepancy will be allocated to the states.[6]

Lease and Plant Fuel

Based on input from OGSM, the NGTDM projects the amount of dry natural gas produced, as well as the amount of gas used in lease and plant fuel operations. The OGSM projects the production of natural gas plant liquids (NGPL) by state/substate. The current NGTDM sets lease plus plant fuel in total as a fixed historical percentage of dry gas production, partially because historical lease and plant fuel was not always provided separately. Lease and plant fuel are taken off the top of the dry gas production volumes with no direct price consequences, as prices are assumed to apply directly to the remaining dry gas production. One option for the new NGTDM is to apply this same approach. However, the projection could theoretically be improved by setting lease fuel as a function of dry gas production (or as a function of a marketed gas estimate) and plant fuel as a function of natural gas plant liquid (NGPL) production, particularly since NGPL production has been growing appreciably more rapidly than dry gas production in recent years.

Looking nationally, the ratio of dry production to lease plus plant fuel has been historically very steady over time. However, lease fuel as a percent of dry or marketed production has a slight upward trend historically which will likely continue to increase with a move from oil to the use of LNG/CNG in lease equipment and plant fuel as a percent of dry production has an even greater downward trend. (Nationally, lease fuel volumes are more than double plant fuel volumes.) So, with more rapid growth in NGPL production, the ratio of plant fuel use to NGPL production has been declining as well, and at a greater rate. Possible explanations for this trend are:

[6] In the current NGTDM this difference is divided equally among the 12 NGTDM regions since it is a relatively small number and there is no fundamental reason to allot more to one regional than another. A similar approach could be taken for the new NGTDM.

1) *an increase in the use of purchased electric power in processing plants (which has been occurring to address emissions issues)*
2) *improved efficiencies (while there have been some efficiency improvements, there are also improved technologies for extracting the liquids which require more energy)*
3) *increased pressure in natural gas entering the plant (while gas from shale plays can be at high pressure initially, this eventually will dissipate over time)*
4) *issues related to data collection*

While the primary driver is of interest, some sort of assumption would need to be made about how this relationship is carried forward if plant fuel is to be set based on NGPL production. If the reason is largely #1, this would most properly require additional changes in the broader NEMS model to account for the added electricity consumption.

In the interest of keeping unneeded complexity to a minimum, particularly for the first version of the new NGTDM, the proposal is to use the same approach as is used in the current NGTDM and assume lease plus plant fuel as a percent of dry gas production at a state level. Natural gas from the offshore will already be directed to a costal state and assumed to be processed in that state. Special handling will be required to account for the plant fuel used in Illinois to process wet gas sent on the Alliance pipeline from Canada. While the data should be checked for other instances of large volumes of wet gas produced in one state and processed in another, it will effectively be ignored unless the volumes are notable.

In the STEO years, lease and plant fuel will be benchmarked to STEO values as is done in the current NGTDM, by deriving a national level factor to scale each of the state level values to align with the national forecast. This will require the NLP to be run multiple times in the STEO years for convergence to occur.

Pipeline fuel usage

Pipeline fuel must be accounted for within the model as one of the components of total consumption, but also plays a role in the pricing of transportation services. The first challenge here is to derive a loss/use factor for each pipeline segment in the model based on available historical data. The second is to separate out the role of pipeline fuel use from other variable charges when establishing variable tariff curves. This will be described in the section on variable pipeline tariffs.

Historical data for pipeline fuel (which also includes fuel for distribution) are available by state on an annual basis and by month on a national basis. While monthly historical numbers are estimated using the relationship of pipeline fuel to total consumption, net of pipeline fuel, the objective is still to align with national monthly data for a consistent accounting with the historical series, if feasible. Within the model, pipeline fuel will be calculated as a percent used/lost on each pipeline link (i.e., as a percent of the flow on each pipeline segment). For the record, since 2009, the survey collecting the data specifically asks for and includes volumes identified as lost; and with added effort on the part of the survey managers these numbers have been improving subsequently. Therefore, it is preferable to use more recent data to set these percentages for the projection. However, in general taking an average over several years can smooth out potential anomalies in any one year.

One factor that could be important in driving pipeline fuel use in the future is the penetration of compressor stations driven by electricity bought off the grid (i.e., not powered from natural gas taken from the pipeline). Initially this potential growth area will not be considered in the new NGTDM, as the underlying assumption is that these levels will be small enough to ignore. Changing this in the model would require:

- *an assumption about the penetration rate of electric compressors going forward*
- *an estimate of the added cost to the variable charge, presumably based on an input from NEMS and accounting for the fact that a portion is assumed to flow using gas and the rest using electricity*
- *a change in the accounting in NEMS, insuring there is no double counting occurring in the industrial demand module for electricity consumption*

In short, this is not worth doing if the volumes are assumed to be small. If there is a basis for changing the percentage going forward, this can be re-evaluated.

The following outlines the steps that will be taken for historical years to derive pipeline fuel as a percent of flow on each pipeline segment.

1. *For each state, sum the flow into and out of each state, as well as the supply and delivered consumption volumes within each state (i.e., excluding lease, plant, and pipeline fuel). Imports and exports should be included with the flow data.*
2. *Divide the historical pipeline fuel in each state by the total state flow from step 1.*
3. *After examining the historical trend of the percentages from step 2 in recent years, to ascertain the most representative years, set an average percentage over these historical years for use in the forecast years.*
4. *For supply and delivered volumes within the state apply the result from step 3 for the associated state.*
5. *For pipeline arcs that cross state or federal borders, set the loss/usage percent as the sum of the percentage from step 3 for the "from" state and the "to" state.*

To align with the national total in an historical or STEO year, a national scaling factor can be applied to all of these percentages, which is set to the desired national pipeline fuel divided by the national pipeline fuel solved for in the previous NEMS iteration or previous NLP solution. In the STEO years, the NLP could be called multiple times with incremental adjustments of the scaling factor until the model aligns with STEO results. In theory a separate scaling factor could be applied to each month, but this is probably overkill. These scaling factors can be extended into the forecast period or scaled out at the user's discretion.

Within the NLP, the pipeline fuel usage/loss is effectively a loss along each of the pipeline arcs and is incorporated into the balancing constraints at each node. So, if 100 units enter one end of a pipeline segment and the pipeline fuel loss percent is 5%, 95 units will arrive at the other end. In addition, if the 100 units was priced at $1.00/unit at the sending node, it will be priced at $1.05/unit [$1.00/(1-0.5)] at the receiving end, not accounting for any additional charges. Once the model solves, pipeline fuel can be calculated by state by multiplying the pipeline fuel loss factors by the total state flows and then aggregated to census division for NEMS or any other desired reporting region.

Imports and Exports

While the focus of the NGTDM is on the domestic natural gas market, the model must also include some representation of imports and exports that will vary in response to market signals and across NEMS scenarios. Initially the representation of imports and exports in the new NGTDM will be similar to what is used in the current module, which has minimal detail. The ultimate intent is to represent Mexico and Canada at a level of detail that is comparable to the United States, to the degree possible (e.g., supportable by available data) and that is consistent with the representation used and results from the international natural gas model currently being developed by EIA. Ideally, data and/or code from the international model will be directly transferable to readily accommodate model updates.

LNG imports and exports will need to be projected for Canada, Mexico, the connected United States, Alaska, and Hawaii. The longer-term goal is to represent LNG trade in a way that mimics the international model without actually modeling the rest of the world. An approach is being developed under a separate effort to accomplish this. It is anticipated that it will involve a reduced form model that will, for example, collapse the demand for LNG exports in Asia into a single price responsive demand curve that can be incorporated in the NGTDM. In addition, there will be some feedback mechanism to reflect the impact that LNG exports will have on the rest of the world.

In the current model Canada is subdivided into an east and west region. Consumption is based on model results from the latest International Energy Outlook (IEO), but set to change in response to higher/lower world oil prices, accounting for the use of natural gas in the production process of oil sands. East/West splits are set exogenously, based either on history or a separate projection (e.g., from the National Energy Board) if available by region. Eastern production is set exogenously and does not change. A set of price responsive equations are used to generate annual supply curves for western production. Monthly consumption and storage data will need to be found or assumed. While historical flow and price data are available at the border, including spot versus contract trade, historical prices and flows within Canada will need to be found or generated given available data, to form a basis for developing pipeline tariff curves.

In the current model, net pipeline imports into Mexico are set equal to production plus LNG imports minus consumption. Consumption is fixed at IEO levels. LNG imports are effectively set exogenously and fixed. A base level production projection is set exogenously with an associated base level price for the Henry Hub. Production is assumed to increase or decrease in response to deviations of the projected Henry Hub price and the base line value. Imports are set by three border crossings based on historical shares. Initially, the representation of Mexico in the NLP will just be fixed volumes at the border. Ultimately, the rapidly evolving natural gas market in Mexico will need to be reflected in the NGTDM.

In most scenario runs of the NGTDM, LNG imports are set at a minimum level into New England. The only time LNG imports are likely to exceed the minimum is in a low oil price case and, even then, the volumes are minimal. The current NGTDM uses LNG import supply curves based on IEO results, which can be used for the initial new NGTDM. The current NGTDM includes a methodology for setting expansion of liquefaction capacity for LNG exports that is executed outside of the balancing routine. While the routine which sets the utilization of the facilities typically results in full utilization, except under low oil prices, the methodology used can be specified as demand curves which can be incorporated into the NLP. As mentioned previously, this approach is likely to change in some aspects with the implementation of a new international hydrocarbon supply model.

In the current version of the NGTDM, Mexico and LNG imports and exports are set exogenously in the STEO years, while imports and exports from Canada are aligned with STEO by tweaking model parameters exogenously (although this approach might be automated for AEO2016). The basic approach is to shift the Western gas supply curve, with multiplicative factors, until the sum of the projected imports across all border crossing aligns with the total import levels from the STEO. In the current model the shifting effectively occurs along both the price and quantity axes. In the new model, a similar approach is expected to be used. As both the Canada and Mexico models are modified the basic approach will be similar, to shift the supply and/or demand curves similarly, across all regions and time periods represented, until the results align with STEO.

Supply

In general, supply will be represented as either a supply curve, where production will directly respond to price in balancing supply with demand, or supply will be fixed at levels set before the market is balanced in the NLP. In theory, a modeler should also be able to fix volumes that are generally represented with a supply curve; however, this is less likely to be desired and could result in problems if the model is left to balance on too limited of a supply pool. Only the price responsive supplies directly impact supply prices, as they will be the source of the marginal supply. Fixed supplies are effectively price takers. Production is forced to align with STEO by ensuring that consumption, imports, and exports align.

Fixed supplies

Supplies that are fixed during the balancing routine in the current model include: associated-dissolved domestic production (from OGSM), eastern Canada production, LNG imports, Mexico imports, Canada imports into East North Central, production via an Alaska or MacKenzie Delta pipeline to the Lower 48, and supplemental supplies (by three categories – synthetic gas from coal, synthetic gas from liquids, other supplemental supplies). In some cases, these supplies are set as a function of the price from a previous NEMS iteration, but are held fixed during the balancing process for reasons that are not relevant to the new formulation. In general if it is not possible or expedient to develop a supply curve for the model, then supplies will need to be fixed and priced based on the regional market price. The working assumption for the first version of the model is to represent these supply types as they are in the current model, however, the code will be formulated to allow each source to be set at a fixed volume or with a supply curve should one be developed.

Price responsive supplies

Price responsive supply, primarily non-associated dry gas production, is represented in the objective function as producer surplus, or the area under the short-term supply curve, and should ideally be specified as a continuous and increasing function. A general approach used in developing supply (and demand) curves is to base them on a price/quantity pair (P0,Q0) that represents the expected or baseline level of production or supply with an associated price, and to build a supply curve off of that point by assuming an elasticity (α). The curve could take either of the following forms:

$$Production = \ Q0 * \left(1 + \frac{\alpha * (Price - P0)}{P0}\right), \qquad or\ alternatively \quad = Q0 * \left(\frac{Price}{P0}\right)^{\alpha}$$

However, for nonassociated dry gas production, the (P0,Q0) point is more than just a random point on the supply curve. The expected production represents an economically viable level and mix of production that producers are planning to make available to the market without either stressing the system or needing to cut-back because of over-supply. As such, the supply curves are built around this expected production point with a shape that drives the solution towards that point while allowing some adjustment to balance the market. This is done by assuming the change in production values will be less responsive to a change in price at volumes exceeding the expected production and more responsive at volumes less than the expected production, as shown in Figure 2, with the (P0,Q0) point at the "knee" of the supply curve. The current plan is to specify the supply curve as a piece-wise linear function, with between three and five segments, very similar to what is used in the current NGTDM. This representation of supply, in combination with how the pipeline tariff curves will be specified (as described in a later section), should result in a reasonable balance in production across regions.

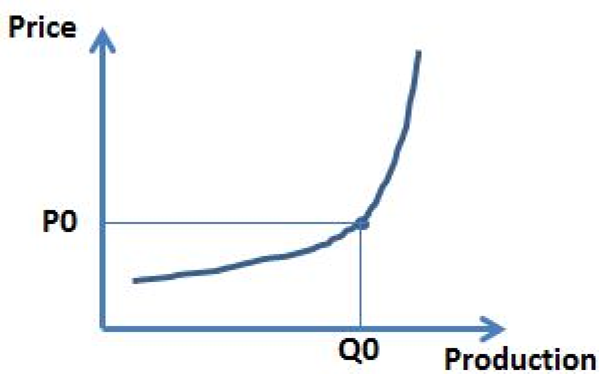

Figure 2 Illustrative supply curve

While OGSM determines expected production at a county level, which can be aggregated to most any regional representation NGTDM might consider, the levels are annual and the NGTDM requires seasonal or monthly production volumes and prices.[7] Two potential approaches were considered. The first was to have the annual regional/state supply curve feed into each season/month market hub node. The mass balance requirement would mean that the monthly production would sum to the annual production on the supply curve and that the associated annual price could be read off of the supply curve. Assuming no gathering charges on the connecting arcs, for simplicity, this generally means that the supply price in each season/month will be the same. Of course the gathering charges along each arc could be allowed to vary and force variation in prices across seasons/months.

The second approach was to define supply curves for each season/month by scaling the expected production by an assumed variation in volume across the seasons/months, which initially would just

[7] For the most part production in the United States in recent years has shown very little if any noticeable seasonal variation. Due to the general variability in prices, it is hard to definitively say the same thing about the associated prices.

reflect the number of calendar days in the period. The value of P0 should presumably be set at the price in the previous forecast year for the indicated region and season/month, not the annual price for the region. Ideally, the production across the months in a year would reflect the expected growth in annual production, so as to avoid a step increase in production from December to January.The current plan is to use the second approach.

For the record, the primary reporting regions for OGSM have New Mexico split into two regions and Texas split into three. Since we currently don't have data to split the consumption into substate numbers for these and other states (e.g., California), the current plan is to allow more than one supply node going into each region/state market hub.

Storage

While storage is a key component of a short-term natural gas market model, its role in a long-term model is less prominent. Two key driving assumptions in the modeling of storage are that 1) weather is normal and 2) annual net storage withdrawals are zero, outside of the STEO years when they will be set to total to STEO projections. In other words, we are not trying to model storage strategies under different circumstances or long-term changes in storage capacity, but do want to account for the use and associated cost of storage in balancing seasonal demand. One of the difficulties in properly representing storage is that the decision to store is generally not a purely economic one. Local distribution companies, the dominant users of seasonal storage, have an obligation to serve the majority of their customers regardless of the weather and must plan accordingly by both storing gas in the off-peak periods and reserving firm pipeline capacity. Previous versions of the NGTDM have attempted to model storage withdrawals/injections based on economics and the results have not been satisfactory (i.e., projected storage usage was much lower than history would indicate). Therefore, in the new NGTDM, storage will be set and fixed outside the NLP and be included as a fixed supply when net withdrawals are positive and a fixed demand when net withdrawals are negative.

Much of the specifics about how storage withdrawals/injections will be set for each season and region are yet to be determined as much of it will be driven by analyzing the data. The preliminary plan is to first establish the seasonal storage withdrawals/injections for the United States and Canada combined (eventually including Mexico) and second share the resulting seasonal/monthly levels to the regions/states included.

For the first step, seasonal/monthly shares, or approximations thereof (e.g., from the previous forecast year), for all of the supply and consumption categories will already be known before the NLP is solved, as well as actual or approximate annual volumes. Categories that are assumed to be constant across the year can be excluded from this calculation, as well as trade volumes between Canada and the United States. North American storage withdrawals for each month will be calculated as the sum of all included consumption categories (e.g., including exports) for the month minus the average monthly consumption over the year, minus a similar calculation for the included supply categories.

The next step will involve allocating the resulting North American withdrawals (positive and negative) across the regions/states. The hope is that historical data reveal a pattern and some potential drivers for where gas is stored now and into the future and that econometric analysis will result in a reasonable approach. One factor that will be considered is regional storage capacity. There is also likely to be a bit of "noise" in the data because of weather influences that will need to be filtered out.

Finally, the cost of storage will need to be factored into the prices paid by final customers. By fixing storage withdrawals in the NLP, the implied assumption is that storage is not a marginal source of supply and that the cost of gas coming out of storage is effectively sunk. Therefore, the costs associated with storage will be added to the price paid by end-users, similar to how pipeline reservation fees will be included and as will be discussed in a later section. We have yet to determine a reasonable way to approximate the costs of storage, which would probably include direct charges related to storing gas, reserving storage capacity, and injection and withdrawal fees, as well as indirect investment costs of holding inventory in storage.

Pipeline Tariffs

The previous versions of the NGTDM set both fixed (reservation fees) and variable tariffs based on a regulated rate calculation. Revenue requirements (or cost of service estimates) were calculated and allocated to fixed and variable rates based on regulated allocation schemes, and were set to dollar per unit charges based on an assumed utilization of capacity or the previous year's flow. More recently, variable rates have been fixed at average historical basis differentials. For fixed rates a curve is set from a (P,Q) point, represented by (revenue requirement/last year's flow, last year's flow). The curve is specified so that the tariff increases rapidly as the flow approaches the pipeline capacity and is extended beyond the current pipeline capacity. This mechanism acts like a hurdle rate by which the model decides to add pipeline capacity when representative peak day consumption levels are flowed through the network. If pipeline capacity is added in one forecast year, the revenue requirement is adjusted accordingly in the next year to capture the impact, using assumed costs for pipeline expansion.

In theory, the revenue requirement calculation provides a mechanism for accounting for the effects of pipeline depreciation and pipeline expansions, as well as changes in regulations and tax laws. In reality, it is not clear that such an approach improves the ability of the model to accurately project regional spot or citygate prices. The current NGTDM sets benchmark factors to align with historical citygate prices, which have been greater than ideal. There are multiple potential reasons for the model not aligning well with history, some of which have already been discussed (e.g., the model's level of aggregation):

- *The calculated regulated rates might not align well with actual posted rates (something which can be hard to assess given the aggregation)*
- *Actual rates charged are frequently negotiated*
- *The mechanism for capturing the effect of reselling unused reserved space to a third party is limited*

An alternate approach proposed for the new NGTDM is to base the "tariffs" on differences between region/state spot prices (i.e., basis differentials) and differences in citygate prices. The primary objective within the NGTDM structure is to produce accurate projections of the spot and citygate prices, not necessarily to produce an accurate projection of the tariffs themselves. However, basing a component of the projection on historical values is only reasonable if the component will not change substantially in the future under current laws and regulations or, preferably, that the primary potential drivers of future changes can be identified and incorporated within the model.

The basic assumption is that there are three components of the differences between prices in one state versus the other: 1) pipeline fuel charges, 2) variable tariff, and 3) fixed charges. We are further assuming that the differences in the spot charges are pipeline and variable charges and that the differences between spot and citygate prices are the fixed charges. While this might not be entirely accurate, it is hoped that it is will provide a reasonable approximation and a structure for projecting forward. Historically, the charges to move gas from point A to point B follow:

$$pipeline\ fuel\ charge\left(\frac{\$}{Mcf}\right) = Spot_A * \left(\frac{1}{1 - \%loss} - 1\right)$$

$$variable\ charges(\$/Mcf) = Spot_B - \frac{Spot_A}{1 - \%loss}$$

$$AnnualFixedCharge\ (\$) = \sum\nolimits_{month} \begin{matrix}\left((Citygate_B - Citygate_A) - (Spot_B - Spot_A)\right) \\ * \ associatedflow\ into\ B\end{matrix}$$

The specification of variable tariffs in the projection is described below, with the role of annual fixed charges included in the section on the pricing submodule. Some adjustments might be necessary to define data for tariffs in Canada and Mexico that allow for a representation that is consistent with the United States.

Variable Tariff Curves

While the pipeline fuel charge will automatically be accounted for in the NLP through a loss in volume, the variable tariff will be set in the NLP using a curve for each interregional arc, to assign a monthly variable tariff as a function of the monthly utilization of the pipe. The intent is to examine the monthly (or daily data, if flows are available), to see if patterns emerge that show the variable charge increasing with increased utilization and decreasing with decreased utilization and that will provide a basis for specifying the curves. The data will also be examined to see if there appear to be any annual trends showing the average tariff increasing or decreasing across time. The working assumption is that the variable tariffs should be reasonably constant across time in real terms and that the tariff curves can be held constant in the forecast period. Until the data are examined it is difficult to speculate about the form of the tariff curves, except that they necessarily will be continuous and increasing, and that they will be capped at the associated pipeline capacity. In order to capture the potential of reverse pipeline flow arcs will be established in both directions between regions and tariff curves based on gas flowing one direction will initially be assumed the same for potential gas flowing the opposite direction. Once historical data are available for gas flowing in both directions this will be reexamined. The NLP will effectively only be able to solve for net flows in each month/season as the optimal solution will result in zero flow in one direction, unless a minimum is established.

Pipeline Expansion

In the first few years of the forecast period, pipeline expansion will be set to historical levels plus capacity under construction or highly likely to be constructed. In years thereafter, before running the NLP to balance supply and demand each season/month, the NLP will be run to determine if the market needs and supports additional pipeline capacity. This will be done by mimicking a colder than normal peak day. Estimated consumption for January will be increased by a user specified percentage (e.g., 15%), which would vary by sector and region. It might also be reasonable to moderately increase the storage withdrawals for the period. An estimate of the unitized reservation fee will need to be added in this case, since the decision to build depends on more than just the variable charges. To estimate the reservation fee with a capacity addition, the current fee (e.g. from the previous year) will be increased to account for new construction vs. depreciated pipes and the estimated increase in volume. Instead of capping the variable pipeline tariff curves at capacity, the curve will be extended beyond the existing capacity, but at a higher rate that is intended to represent a hurdle rate for adding new capacity. Ideally the hurdle rates will reflect the relative cost of adding capacity on each arc; however, initially this will be a model assumption, if and until a methodology is developed to estimate/justify the amount. The anticipated effect is that flow on more economically desirable routes that are relatively full will be pushed to other routes, if available, to a point, but that eventually capacity will need to be added. If pipeline capacity is added, the annual fixed charge going forward should be increased accordingly and likely increased proportionately to the level of capacity added. It is likely that the NLP will also need to be run for a peak summer month using a similar approach, to estimate the needs and support for pipeline capacity additions in warmer regions (e.g., Florida).

This approach will allow pipeline capacity to be added incrementally as needed in each year of the forecast. While this is something of a distortion of how expansion projects actually are built, in larger discrete units, it is a reasonable approximation. Since pipeline capacity is being added to satisfy current year needs, the assumption is that the actual projects were planned ahead of time, as necessary, in anticipation of the future need. A likely future enhancement of the model will be to include a longer-term look ahead over the life of the pipeline, defined on a net present value basis, which would reflect beyond the immediate need for the pipeline. This would be of particular importance if the need for the pipeline is expected to decline into the future. This could conceivably be done by generating an expected average peak demand load over the life of the pipeline with greater weight on volumes in the near-term.

Pricing Submodule

As discussed previously the use of the NLP will be to determine the volumes of gas in the system that balance supply and demand, including setting supply and demand levels that are not previously fixed. Shadow prices at the nodes in the network are based on variable pipeline charges, generally equal the marginal price, and should therefore be a reasonable estimation of spot market prices. However, any fixed charges in the system are not represented in the NLP and will be added afterward in the Pricing Submodule. Fixed charges will include fixed pipeline charges (e.g., reservation fees), storage charges, and added costs when a minimum constraint is binding.[8] The fixed charges will be added to the spot price in each region/state to set citygate prices. The process for doing this, and for then setting delivered prices, is described below. The methodology for setting fixed storage charges has yet to be determined. Initial values for annual fixed pipeline charges are based on historical relationships, as described in the previous section on tariffs. The fixed charges will be increased, potentially just proportionately, if pipeline capacity is added, but should theoretically be decreased as pipeline depreciation outpaces any added costs for pipeline refurbishments. These assumptions will be decided later.

Building a hierarchical acyclic network

[8] Difficulties can arise in interpreting shadow prices when minimum constraints are introduced and they are binding. For the most part, we are avoiding the use of minimum constraints. However, if one considers a minimum constraint as a potentially noneconomic choice (e.g., a take-or-pay contract), then the sunk cost associated with the transaction, while not affecting flows and marginal prices, can be added after the fact as a fixed charge that end-users still have to pay.

With the established net flows between regions/states coming out of the NLP, a hierarchical acyclic network can be formed which can be used to follow flows through the network and progressively add fixed charges. The process of establishing the hierarchical network can best be described with an example.

If each of the arcs in a 6-node network with nonzero from/to flows are identified with a 1 in a matrix the following could result:

	1	2	3	4	5	6
1	0	0	0	1	0	0
2	0	0	0	0	0	1
3	1	0	0	1	1	0
4	0	1	0	0	0	1
5	0	0	0	0	0	1
6	0	0	0	0	0	0

The acyclic arc is built by identifying the nodes at the top level, following downward. So, in this case the only node at the **level 1 is node 6**, since there are all zeros in row 6. Eliminating row 6 and column 6 leaves:

	1	**2**	**3**	**4**	**5**
1	0	0	0	1	0
2	0	0	0	0	0
3	1	0	0	1	1
4	0	1	0	0	0
5	0	0	0	0	0

The only nodes at **level 2 are nodes 2 and 5**, leaving after eliminating their rows and columns:

	1	**3**	**4**
1	0	0	1
3	1	0	1
4	0	0	0

Continuing on shows**, level 3 with node 4**, **level 4 with node 1**, and **level 5 with node 3**, resulting in the network shown in Figure 3.

Flowing volumes down through the network

In order to unitize the fixed charges, which are specified in dollars, the consumers that will be paying the fixed charges need to be identified and the flow on each arc associated with these consumer's needs to be quantified by going down the hierarchical network, from level 1 to level 5 in the example. An assumed percentage of the consumption in each sector will be applied to determine the volume of the total gas that is assumed associated with fixed charges in each region/state, to be referred to as "firm" consumption. These percentages should roughly correspond to the consumption or percent of consumption that will be priced based off of the citygate price in each node as opposed to the spot price in each node.

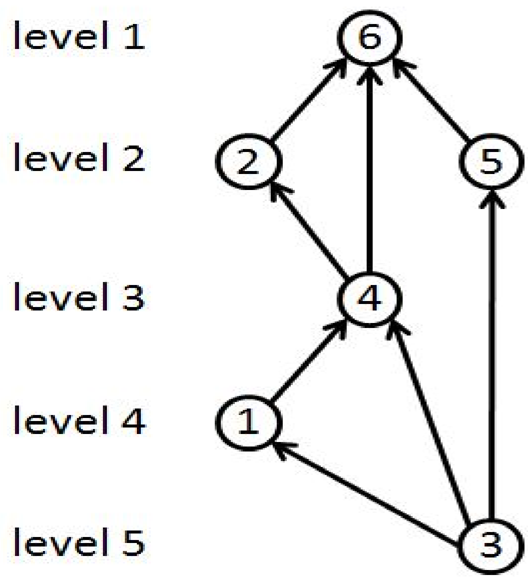

Figure 3. Example of hierarchical, acyclic network

Starting at level 1, the percentage of firm consumption in node 6 will be applied to the flow on each of the three arcs going into node 6 from other nodes, as well as from local storage. Then, going to level 2 and node 2, the amount of firm consumption needed to supply node 2 equals the firm consumption local to node 2 plus the firm flow out of node 2 to node 6, similarly for node 5. This share of firm consumption needed in node 2 is then applied to the flow on each of the arcs going into node 2 (in this case just the arc from node 4), including storage. This continues until a volume of firm flow is assigned to each arc and storage node. These volumes are to be used in the next step.

Flowing fixed charges up through the network

Once firm consumption levels are established for each of the components with an associated fixed charge (i.e., pipelines and storage), then the fixed charges can be assigned throughout the pipeline network, starting at the bottom of the hierarchical network and moving up. First of all, the established annual fixed charge (specified in dollars) for each arc will be allocated to the months based on number of days in each month. Going back to the example, starting at level 5 and node 3, the fixed charges associated with withdrawals from storage in node 3 will be allocated proportionately to the firm consumption in node 3 and the firm flows on the three arcs exiting node 3. The fixed charges assigned to each of the three exiting arcs will be added to the fixed charges already directly assigned to these arcs. The initial citygate price for node 3 will be set to the spot price at node 3 (in $/Mcf) plus the assigned fixed charge to the firm consumption (in dollars) in node 3 divided by the firm consumption in node 3.

Next, a similar calculation will be performed for node 1 at level 4, but the fixed charges associated with the firm flows from arc 3 to arc 1 (and other arcs that happen to flow into 3 from other nodes), will be added to the fixed charges associated with withdrawals from storage in node 1. This total fixed charge will similarly be allocated proportionately to the firm consumption in node 1 and the firm flow on the arc exiting node 1 (or other arcs that happen to flow out of node 1 to other nodes). Again, the citygate price will be assigned for node 1 as was done for node 3 and the proportioned fixed charges will be added to the arc from node 1 to node 4 as was done for the three arcs exiting node 3. This process will be repeated progressively through level 1 and until citygate prices are assigned to all of the nodes.

Setting delivered prices

Finally, once wholesale equivalent prices are established at the market hub and citygate in each region/state and season/month, delivered prices can be set to send back to the other modules in NEMS, as appropriate. The NEMS system requires average annual sectoral prices by Census Division, and for electric generators prices are required for 17 regions and 3 seasons. Three basic approaches can be taken: 1) calculate quantity-weighted average wholesale prices for a lower level of aggregation (presumably to the level needed in the NEMS system) and then apply distributor tariffs, 2) assign distributor tariffs at the region/state level and then calculate quantity-weighted average delivered prices, or 3) some combination of 1 and 2 by assigning distributor tariffs as a level of aggregation more than the region/state, but less than the level needed by NEMS.

In the current NGTDM, markups to delivered prices (i.e., distributor tariffs) are established using peak and offpeak equations specified for each of the 12 NGTDM regions or the 17 electric regions. For all but the electric sector the distributor tariffs are estimated with historical data and the seasonal prices are averaged, using quantity weights, to arrive at an annual average delivered price. For industrial, an assumed differential is applied to arrive at separate prices for energy-intensive and non-energy-intensive industries. For electric generators, the “distributor” tariff is initially set at an historical average and allowed to increase/decreased as the electric sector’s share of the total delivered volumes increases/decreases.

The decision about the level of disaggregation to assign and apply distribution markups will largely depend on an analysis of the data. It is generally believed that it is preferable to represent market behavior at a lower level of aggregation and then averaging/aggregating for reporting, estimating across series can provide more data points and make for a more sound estimation. The second factor to be considered in assigning delivered prices from wholesale prices is whether to 1) set distributor tariffs based on volumes and not include the wholesale price in the estimation, 2) set distributor tariffs as a function of the wholesale price (if statistically significant) as well as other explanatory variables, or 3) directly set delivered prices as a function of the wholesale price as well as other explanatory variables. The first approach is what is used in the current NGTDM. However, the other two options will be examined for the new NGTDM.

For the most part, it is reasonable to assume that the residential and commercial sectors are largely firm customers and should be based off of the citygate price. This also makes sense for the non-energy-intensive industrial price and the price paid for gas delivered to compressed natural gas station for vehicles. The other sectors (energy-intensive industries, electric generators, and gas delivered to liquefaction facilities), including gas that is exported, are more likely influenced by the spot price and should be set accordingly. However, the data will be examined to determine if these assumptions hold and whether some combination of the two wholesale prices seems to be a better indicator. Whatever assumptions or parameters are used in setting delivered prices will also be used when setting the firm consumption levels described previously.

Other outputs to NEMS

As a submodule to NEMS, the NGTDM is responsible for not only projecting delivered prices by sector and region, but all of the following for other NEMS modules:

- *Realized nonassociated dry gas production at the region/state for OGSM (values of which can be taken directly out of the NLP, making sure to account properly for lease and plant fuel consumption)*
- *Total dry gas production at an aggregate report level for NEMS reports and for other NEMS modules.*
- *Lease and plant fuel consumption (a percentage of dry gas production, which can be set using an accounting row in the NLP, summed to the Census Division)*
- *Pipeline fuel use (a percentage of the flow through each node, using an accounting row in the NLP, and summed to the Census Division)*
- *Supply prices at the region/state for OGSM (i.e., the price seen by producers) (should be the shadow price at each supply node, but can be verified by evaluating the supply curves at the dry gas production level)*
- *Supply prices averaged to an aggregate report level for NEMS reports and for other NEMS modules*
- *Import and export volumes and prices, largely for the Macroeconomic Module of NEMS*
- *Total national supplemental supplies produced, as well as other fuels used to produce synthetic natural gas by Census Division*

In addition, the NGTDM will provide projections for the NEMS report writer to fill existing and new tables containing the following:

- *Interregional natural gas flows and pipeline capacities*
- *Import and export volumes and prices by country and type (pipeline versus liquefied natural gas)*
- *Citygate prices by Census Division and selected or averaged spot prices*
- *Detailed elements related to the representation supply and demand in Canada and Mexico*

Finally, a reporting mechanism will be developed to analyze and debug the results of the NLP and the Pricing Submodule.