Eastern Interconnection Planning Collaborative

Phase 2 Report:

Interregional Transmission Development and Analysis for Three Stakeholder Selected Scenarios And Gas-Electric System Interface Study

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11 Gas-Electric System Interface Study Target 4: Dual-Fuel Capability and Firm Transportation Alternatives

Executive Summary

In the Target 1 report, LAI reported that the majority of gas-fired generators across the Study Region, which encompasses the Independent Electricity System Operator (IESO) of Ontario, Independent System Operator – New England (ISO-NE), Midcontinent Independent System Operator (MISO), New York Independent System Operator (NYISO), PJM, and the Tennessee Valley Authority (TVA), rely on non-firm transportation arrangements to meet the PPAs' daily scheduling requirements, excluding generators in Ontario and TVA. In the Target 2 report, LAI derived the distribution of frequency and duration of transportation constraints affecting the availability of interstate and storage infrastructure to serve the coincident requirements of the gas utility customers and gas-fired generators under three distinct market and resource scenarios as well as an array of sensitivities. The sensitivities were designed to test the ability of the Study Region's gas infrastructure to serve electric generation in light of market, environmental, and economic uncertainty factors. The Target 4 analysis compares dual-fuel capability versus firm pipeline transportation for gas-fired generators to achieve fuel assurance for electric reliability.

Target 4 research identified the dual-fuel capable generators in the Study Region, the on-site storage capacities for back-up fuel at these facilities, and the resupply modes employed to replenish back-up fuel supplies. The operating issues and costs for developing dual-fuel capability at new simple cycle (SC) and combined cycle (CC) generating units were examined, along with the operational considerations involved with switching from natural gas to ultra-low sulfur diesel (ULSD) fuel. Dual-fuel capable units have utilized a range of distillate fuel oils as back-up fuel, including #2 fuel oil, ULSD, kerosene, and ultra-low sulfur kerosene. Going forward, new gas-fired plants are expected to utilize ULSD as the primary back-up fuel. The anticipated heavy reliance on ULSD constitutes a major change in the distillate oil market, resulting in a conversion of the majority of the transportation fleet, distribution systems, and storage facilities from higher sulfur distillate fuel oils to ULSD. Consequently, the ULSD supply chain is capable of meeting dual-fuel generators' back-up fuels needs. Importantly, improvements in the liquidity and availability of ULSD have little or no bearing on the availability and deliverability on short notice of residual fuel oil (#6 FO) for the old-style steam turbine generators in many parts of the Study Region, in particular, ISO-NE, downstate New York and the MAAC portion of PJM.

A total of 561 dual-fuel capable units were identified in the Study Region, including dual-fuel steam units usually burning #6 FO as the alternate to natural gas, as well as existing SC and CC units that typically burn distillate fuel oil as back-up. Data regarding on-site fuel storage and resupply modes were developed for 48 representative plants across the Study Region, using publicly available sources such air permits and regulatory filings. The plants in the database have a wide range of on-site storage capacities with the average for on-site distillate fuel oil storage equivalent to 96 hours at full load operation.

The ability to utilize back-up fuel for each plant is determined by the conditions of air permits and local zoning approvals that govern the delivery, on-site storage and combustion of back-up fuel. Permits for new dual-fuel plants typically limit the number of hours that a plant can operate

on back-up fuel in any 365-day period, since operation on ULSD has higher nitrogen oxides (NO_x) and particulate matter (PM) emissions than on natural gas. The most common limit is 720 hours, but some recent permits have established lower annual hourly limits. Converting an existing gas-only plant to dual-fuel capability will require an air permit modification. If the use of ULSD will cause a significant net increase in NO_x and PM emissions, the permit modification may require that existing pollution controls be up-graded. In addition, retrofitting a gas-only plant to burn ULSD may require local zoning authorizations to allow construction of on-site storage tanks and to allow changes in local traffic patterns to accommodate increased truck traffic. Additional costs will be incurred in order to upgrade pollution controls, add storage tanks and back-up fuel handling equipment, modify fuel combustors, and upgrade plant control systems. The cost to retrofit an existing gas-only plant to burn back-up fuel is usually higher than the cost to incorporate dual-fuel capability in new construction.

To analyze comparative costs for dual-fuel plants, SC and CC configurations and equipment were identified that are representative of recently constructed and planned dual-fueled plants across the Study Region. General Electric (GE) LM6000 and GE LMS 100 combustion turbine (CT) models for SC configurations in the range of 50 MW to 200 MW, GE 7F.05 and Siemens SGT6-5000F CT models for SC configuration in the 200 MW to 400 MW range, and GE 7F.05 and Siemens SGT6-5000F CT models for CC configurations in the range of 300 MW to 650 MW were analyzed. Performance and operating characteristics of each of these CT models were obtained from the manufacturers. Cost estimates were obtained from CT manufacturers, recent Cost of New Entry (CONE) studies, and Federal Energy Regulatory Commission (FERC) filings. The incremental installed capital cost for including dual-fuel for a 2x1 7FA CC for a base site was estimated to be $17.8 million, but the cost model provides for locational variations. Dual-fuel capable SC and CC plants also incur higher fixed operation and maintenance (O&M) costs for maintaining additional equipment, incremental property taxes and insurance, periodic liquid fuel tests, and carrying costs of back-up fuel inventory. Total incremental fixed O&M costs for a 2x1 7FA CC were estimated to be $1.4 million/year.

Equipment vendors of heavy-frame dual-fuel CTs claim that their units can switch between fuels “on-the-fly”, or while operating at up to 80% to 85% of full load. The transfer can take place in under a minute provided that liquid fuel is available and recirculating at the required pressure and temperature. Initiation of recirculation can take several minutes and requires operator intervention. Vendors of some aeroderivative CTs claim that fuel switching can be achieved at full load if liquid fuel recirculation is in operation, but the switch itself requires operator intervention. Plant owners generally prefer to switch fuel at less than the maximum load to reduce the risk of spikes in NO_x or particulate emissions. The switchover to liquid fuel may result in the loss of operating flexibility in light of generators’ preference to operate at a uniform output level on oil to reduce the risk of emissions excursions.

A set of location-specific cost comparisons between dual-fuel capability and firm transportation service as a means of achieving fuel assurance was undertaken. For each of 27 locations selected by the PPAs, inputs to the dual-fuel cost model such as a labor cost factor, tax rates, and permit restrictions were identified. Particular attention was paid to those characteristics which would affect the liquid fuel inventory level and storage tank size, such as location of a source of liquid fuel and delivery logistics. For each location, a net cost of firm transportation for natural gas was established, based on the reservation cost for incremental capacity on the most likely pipeline path from a source (such as Marcellus) to the location. Adjustments were made for locations likely to be served by an LDC. Firm transportation rates were then netted against the avoided cost of non-firm transportation over the same path adjusted for pipeline limitations during the peak heating season observed in the Target 2 analysis.

All costs were ultimately expressed as an annual levelized cost per kW over a 20-year study term beginning in 2018 for comparison sake. Levelized annual cost per kW of installed capacity was chosen because it allows for a relative comparison of fuel assurance cost among plants of different capacities and heat rates.

Cost categories for dual-fuel capability include capital recovery for incremental combustion turbine scope cost, incremental balance of plant cost (including, where applicable, demineralized water for injection to control NO_x, the cost of ULSD storage tanks, the cost of acceptance testing on ULSD, and the cost of emission reduction credits. Carrying charges on ULSD inventory, and incremental fixed O&M costs were also incorporated in the derivation of annual levelized cost, including regular testing on ULSD. Cost categories for the firm transportation option include the pipeline reservation charges, capital recovery for any laterals required to provide firm service for the last leg across the supply chain, and an offset to account for the avoided cost of non-firm transportation, as more fully described in Section 11.6.3.

At most of the PPA-selected locations, dual-fuel capability has a much lower cost for a new combined cycle plant than firm transportation, as shown in Figure ES 11-1 on the following page. For simple cycle plants, the difference is even more pronounced, as shown in Figure ES 11-2. The cost of dual-fuel capability is generally similar across the range of locations, with the most significant variations arising from the inventory levels and tank volumes for locations with barge delivery, relative to those locations that can be replenished via truck. Firm transportation for the New England locations tends to be very expensive because of constraints on pipeline capacity serving the region. Notably, whether or not a seasonal LNG service leveraged from the existing Suez Distrigas and/or Repsol Canaport LNG import facilities is a good substitute for oil-based dual-fuel capability was not tested in this Target 4 report. Locations in MISO, TVA, and some in PJM show relatively low cost for firm transportation, since recent expansion capacity has been constructed at the system rate, or, in some instances, where existing capacity may not be fully subscribed due to decontracting.

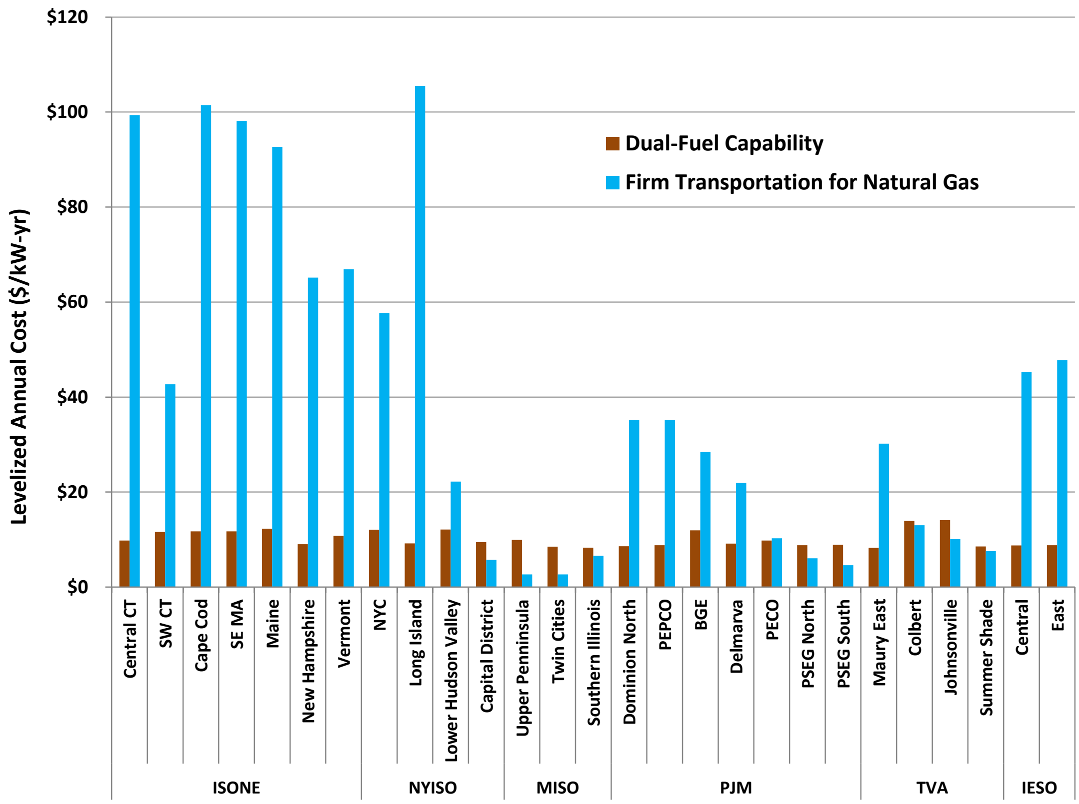

Figure ES 11-1. Levelized Annual Cost Comparison for Combined Cycle Plant

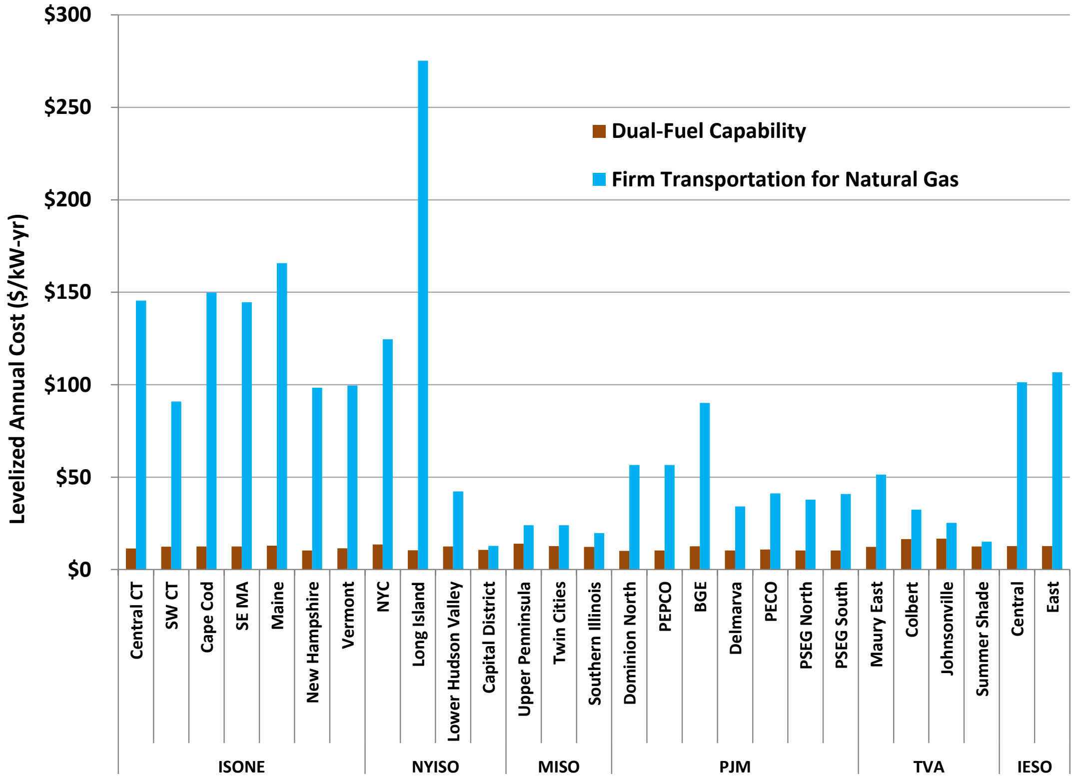

Figure ES 11-2. Levelized Annual Cost Comparison for Simple Cycle Plant

With few exceptions, dual-fuel capability appears to be much less costly with respect to reducing the direct cost as a strategy to achieve fuel assurance. The primary reasons supporting these results are five-fold: (i) existing pipelines in constrained locations are typically fully subscribed, thereby requiring a pipeline to add expensive new facilities to serve a gas-fired generation plant; (ii) generators behind LDC gate stations would be expected to bear the high cost of local facility improvements to ensure year-round service in addition to mainline improvements from the producing basin to the local system; (iii) the avoided cost of non-firm transportation is not sufficiently high in most constrained locations to significantly reduce the net cost of incremental firm transportation service; (iv) the capital charges, inventory carrying charges and incremental fixed O&M associated with dual-fuel capability are comparatively low; and (v) structural change in the distillate oil market has and will continue to improve the logistics of ULSD replenishment during cold snaps or outage contingencies.

Despite the ostensible economic superiority of the dual-fuel capable solution to the challenge of maintaining fuel assurance for electric reliability, there may be other commercial reasons that otherwise induce generators to invest in firm transportation.

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List of Acronyms

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#6 FO	Residual fuel oil, No. 6 Fuel Oil
BACT	Best Available Control Technology
Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
Btu	British thermal units
CC	Combined cycle
CONE	Cost of New Entry
DLN	Dry Low NO_x
DOE	Department of Energy
DR	Demand response
Dth	Dekatherm
EIA	Energy Information Agency
EIPC	Eastern Interconnection Planning Collaborative
EISPC	Eastern Interconnection States Planning Council
EPA	Environmental Protection Agency
EPC	Engineer, Procure, Construct
ERC	Emission Reduction Credit
F-D	Frequency-Duration
FERC	Federal Energy Regulatory Commission
FLE	Full Load Equivalent
FOA	Funding Opportunity Announcement
Gal	Gallon
GJ	Gigajoule
HRSG	Heat Recovery Steam Generator
IESO	Independent Electricity System Operator of Ontario
INGAA	Interstate Natural Gas Association of America
ISO-NE	Independent System Operator-New England
LAER	Lowest Achievable Emission Rate
LAI	Levitan & Associates, Inc.
LDC	Local distribution company
LIPA	Long Island Power Authority
LNG	Liquefied natural gas
Mcf	Thousand cubic feet
MDQ	Maximum Daily Quantity
MDth	Thousand dekatherms
MDth/d	Thousand dekatherms per day
MISO	Midcontinent Independent System Operator
MMBtu	Million British thermal units
MMcf	Million cubic feet
MMcf/d	Million cubic feet per day
MW	Megawatt
MWh	Megawatt hour
MWh/h	Megawatt hour per hour
NA NSR	Non-Attainment New Source Review
NAAQS	National Ambient Air Quality Standards
NAPP	Northern Appalachia
NO_x	Nitrogen oxides
NSR	New Source Review
NYISO	New York Independent System Operator
NYMEX	New York Mercantile Exchange
O&M	Operation and maintenance

OTR	Ozone Transport Region
PJM	PJM Interconnection, LLC
PM	Particulate matter
PPA	Participating Planning Authority
ppm	parts per million
PRB	Powder River Basin
PSD	Prevention of Significant Deterioration
PV	Photovoltaic
RCI	Residential, commercial, industrial
RTO	Regional Transmission Organization
SC	Simple cycle
SCF	Standard cubic feet
SCR	Selective catalytic reduction
SIP	State Implementation Plan
SO_2	Sulfur dioxide
SPP	Southwest Power Pool
SSC	Stakeholder Steering Committee
STG	Steam Turbine Generator
TDS	Total dissolved solids
tpy	tons per year
TVA	Tennessee Valley Authority
ULSD	Ultra-low sulfur diesel
ULSK	Ultra-low sulfur kerosene

List of Interstate Pipelines

Algonquin	Algonquin Gas Transmission LLC
Alliance	Alliance Pipeline LP
AM AlaTenn	American Midstream (AlaTenn) LLC
AM MidLa	American Midstream (MidLa) LLC
ANR	ANR Pipeline Company
Big Sandy	Big Sandy Pipeline LLC
Bison	Bison Pipeline LLC
Creole Trail	Cheniere Creole Trail Pipeline, LP
CNYOG	Central New York Oil and Gas LLC
Columbia Gas	Columbia Gas Transmission LLC
Columbia Gulf	Columbia Gulf Transmission LLC
Constitution	Constitution Pipeline Company
Crossroads	Crossroads Pipeline Company
Destin	Destin Pipeline Company LLC
Dominion	Dominion Transmission, Inc.
Dominion Cove Point	Dominion Cove Point LNG, LP
East Tennessee	East Tennessee Natural Gas LLC
Eastern Shore	Eastern Shore Natural Gas Company
Empire	Empire Pipeline, Inc.
Enable	Enable Gas Transmission LLC
Equitrans	Equitrans, LP
Fayetteville Express	Fayetteville Express Pipeline LLC
Florida Gas	Florida Gas Transmission Company LLC
Granite State	Granite State Gas Transmission, Inc.
Great Lakes	Great Lakes Gas Transmission LP
Guardian	Guardian Pipeline LLC
Gulf Crossing	Gulf Crossing Pipeline Company LLC
Gulf South	Gulf South Pipeline Company, LP
Horizon	Horizon Pipeline Company LLC
Iroquois	Iroquois Gas Transmission System, LP
KM Illinois	Kinder Morgan Illinois Pipeline LLC
KM Louisiana	Kinder Morgan Louisiana Pipeline LLC
KO Transmission	KO Transmission Company

M&N	Maritimes & Northeast Pipeline LLC
Midcontinent Express	Midcontinent Express Pipeline LLC
Midwestern	Midwestern Gas Transmission Company
Millennium	Millennium Pipeline Company LLC
Mississippi River	Enable Mississippi River Transmission LLC
MoGas	MoGas Pipeline LLC
NFG	National Fuel Gas Supply Corporation
NGPL	Natural Gas Pipeline Company of America LLC
NGO	NGO Transmission, Inc.
Northern Border	Northern Border Pipeline Company
Northern Natural	Northern Natural Gas Company
Ozark	Ozark Gas Transmission LLC
Panhandle Eastern	Panhandle Eastern Pipe Line Company, LP
PNGTS	Portland Natural Gas Transmission System
Rockies Express	Rockies Express Pipeline LLC
Sabal Trail	Sabal Trail Transmission, LLC
Sabine	Sabine Pipe Line LLC
Southeast Supply Header	Southeast Supply Header LLC
Southern	Southern Natural Gas Company LLC
Southern Star Central	Southern Star Central Gas Pipeline, Inc.
Tennessee	Tennessee Gas Pipeline Company LLC
Texas Eastern	Texas Eastern Transmission, LP
Texas Gas	Texas Gas Transmission LLC
Tiger	ETC Tiger Pipeline LLC
TransCanada	TransCanada PipeLines Ltd.
Transco	Transcontinental Gas Pipe Line Company LLC
Trans-Union	Trans-Union Interstate Pipeline, L.P.
Trunkline	Trunkline Gas Company LLC
Union Gas	Union Gas Ltd.
USG	USG Pipeline Company LLC
Vector	Vector Pipeline LP
Viking	Viking Gas Transmission Company
WBI Energy	WBI Energy Transmission, Inc.

Note on Conversion Factors

Natural gas is measured by volume or heating value. The standard measure of heating value in the English system of units is millions of British thermal units or “MMBtu.” Dekatherms (Dth) are also a standard unit of measurement. One Dth is equal to ten therms or one MMBtu. The standard measure of heating value in the metric system is gigajoule (GJ); one GJ is slightly smaller than one MMBtu (1 GJ = .948 MMBtu).

The standard measure of gas volume in the English system of units is standard cubic feet or “scf.” The “s” for standard is typically omitted in expressing gas volume in cubic feet. Therefore “scf” is typically shortened to “cf.” Because the heating value of natural gas is not uniform across production areas, there is no one fixed conversion rate between gas volume and heating value. Pipeline gas in North America usually has a heating value reasonably close to 1,000 Btu/cf. Therefore, for discussion purposes, one thousand cubic feet (Mcf) is roughly equivalent to one million Btu (MMBtu).

The standard measure of gas volume in the metric system is cubic meters (m^3). The conversion between metric and English volume measures is 1 m^3 = 35.31 cf. There are a number of different volumetric conventions used in Canada and the U.S.

$$\mathbf{1\ Mcf \approx 1\ MMBtu = 1\ Dth \approx 1\ GJ}$$

$$\mathbf{1\ Bcf = 1{,}000\ MMcf \approx 10^6 MMBtu = 10^6 Dth \approx 10^6\ GJ = 1\ PJ}$$

Foreword

In mid-2009, the DOE issued a funding opportunity announcement (FOA), "Resource Assessment and Interconnection-level Transmission Analysis and Planning," DE-FOA-0000068, funded by the American Recovery and Reinvestment Act of 2009. PJM Interconnection, LLC (PJM) was selected as the recipient of the Topic A portion of this FOA for the Eastern Interconnection and subsequently entered into a cooperative agreement with DOE's National Energy Technology Laboratory. The Eastern Interconnection Planning Collaborative (EIPC) was formed in 2009 by 25 of the major eastern utilities to conduct the work of PJM's award under this funding opportunity, DE-OE0000343. PJM's award under DOE's funding opportunity was divided into two phases – Phase 1 and Phase 2. Phase 1 focused on the formation of a diverse stakeholder group, the SSC, and its work to model public policy "futures" through the use of macroeconomic models. This first work effort examined eight futures chosen by the SSC. The final undertaking in Phase 1 was for the SSC to choose three futures scenarios to pass onto Phase 2 of the project. Phase 2 of this project focused on conducting the transmission studies and production cost analyses on the three scenarios chosen by the stakeholders at the end of Phase 1. This work included developing transmission options, performing a number of studies regarding grid reliability and production costs of the transmission options, and developing generation and transmission cost estimates for each of the three scenarios.

This project is intended to complement the work of the Eastern Interconnection Topic B recipient of DE-FOA-0000068, the National Association of Regulatory Utility Commissions, and its awardee, the EISPC. EISPC comprises regulatory representatives from the 39 states of the Eastern Interconnection, along with the District of Columbia, and the City of New Orleans. The work has also benefited from close interaction with an SSC representing a wide range of interests. DOE is additionally supporting the program through work at selected national laboratories. The EIPC is grateful to DOE and to all the above participants for their contributions.

11.1 Introduction

The extreme weather experienced by the PPAs during the Polar Vortex and subsequent events in January and February 2014 resulted in significant challenges as the PPAs worked to ensure electric reliability in many parts of the Study Region. As part of the four-target Scope of Work undertaken for the EIPC, in this Target 4 study Levitan & Associates, Inc. (LAI) has addressed different ways gas-fired generation can satisfy fuel assurance objectives for purposes of electric reliability. One way to meet the fuel assurance objective is to obtain firm transportation from the producing gas basin or liquid trading point to the generation station. Another approach is to invest in dual-fuel capability.

As discussed in the Target 1 report, the majority of gas-fired generators operating in the Study Region do not have firm transportation entitlements on interstate pipelines, thereby exposing the generator to natural gas interruptions when pipeline congestion materializes during the peak heating season, December, January, and February. Generators in IESO and TVA typically have firm transportation entitlements for all or the majority of the plant's Maximum Daily Quantity (MDQ), and thus represent the exception to the general rule regarding gas-fired generator reliance on non-firm transportation. Consistent with the study paradigm defined by the PPAs and presented to stakeholders, in this Target 4 report the relative economics of incremental firm transportation are compared to dual-fuel capability for a new CC plant or SC gas turbine unit. Before addressing the relative economic costs associated with achieving fuel assurance, other background information pertaining to liquid fuel storage capability, logistical concerns associated with the restocking or replenishment of liquid fuel capability, operating characteristics of new gas turbine technology, and environmental permitting issues are presented.

Investment in dual-fuel plant capability, coupled with on-site liquid fuel storage and resupply arrangements, is a viable way to satisfy fuel assurance objectives for electric system reliability. Based on data provided by the PPAs, LAI developed a list of existing dual-fuel generators. We supplemented this list with other information from LAI's database of dual-fuel capable units based on: air permits and permit applications, state commission and federal filings, state environmental agency documents, and company reports. Air permit, local zoning, plant equipment, and land challenges associated with converting an existing plant from gas-only to dual-fuel capability are addressed.

LAI contacted leading manufacturers of aeroderivative and industrial frame CTs to obtain the current operating characteristics of the most common CTs burning gas and fuel oil. Coordination with manufacturers serves as a basis for the identification of incremental equipment and systems required for dual-fuel capability. In close consultation with the PPAs, LAI reviewed the most common gas turbine technology types that have been or will be commercialized. Four plant configurations are evaluated, as follows:

- Two SC plants utilizing GE LM6000 aeroderivative CTs and the GE LMS100 hybrid CT, and
- Two CC plants utilizing GE 7F.05 and Siemens SGT6-5000F heavy frame CTs.

To facilitate the Target 4 research goals defined by the PPAs, LAI developed a Cost Model. The Cost Model draws from engineering economic analyses relating to the CONE performed by certain of the PPAs and their respective advisors. In addition, LAI has incorporated various operational, financial and/or economic adjustments to the CONE studies based on various location specific assumptions made by LAI. These additional assumptions pertain largely to the incremental cost of dual-fuel capability for a new SC or CC plant in various locations across the Study Region. Based on the frequency and duration of the transportation constraints identified in Target 2, twenty-seven constrained locations across the Study Region have been evaluated.

LAI has evaluated the structure of the liquid fuel market to backup gas-fired generators' primary reliance on natural gas. The liquid fuel market includes the availability of ULSD as well as the transportation logistics associated with replenishment of existing oil inventory. Emphasis has been placed on the delineation of oil and gas interaction effects, the capability of the petroleum delivery supply chain to keep pace with dual-fuel capable generation plant requirements, and noteworthy regional or intra-regional differences. LAI has therefore assessed the impact of seasonal constraints on the ability of truck haulers and barges to meet the coincident requirements of high priority residential, commercial and industrial (RCI) customer loads while replenishing oil inventories at dual-fuel capable units.

In order to assess the constraints associated with generator pressure-sensing limitations on fuel switching capability, LAI worked directly with prominent gas turbine vendors to obtain fuel-switching information. This information included the requisite timing associated with switching fuels, on-the-fly switching from natural gas to oil without dispatching off-line to accommodate the changeover, and the success factors that make or break a successful transition to liquid fuel use.

LAI has evaluated the relative costs associated with the establishment of fuel assurance through firm transportation entitlements versus dual-fuel capability. Economic tradeoffs between fixed and variable costs underlie the economic determination of relative costs. The choice between firm transportation and dual-fuel capability differ significantly in terms of cost, operational requirements, air emissions, and electric system impacts from the PPAs' perspective. In performing the analysis of the merit of dual-fuel capability in comparison to the use of firm transportation, LAI has determined the relevant costs associated with each option. Quantification of the relative benefits to generators or the PPAs is not part of the Target 4 inquiry. Therefore, all benefits are synonymous with fuel assurance. Development of a flexible planning tool provides the PPAs with a structured analytic framework that can be updated on a regular basis in response to changing market and operational dynamics.

11.2 Dual-Fuel Capable Generators, Backup Fuel Storage, and Delivery Modes

11.2.1 Overview

LAI developed a list of dual-fuel capable generators for the study region based on data provided by the PPAs and data for the generating units that were included in the AURORAxmp model. A data request seeking information by generating unit regarding back-up fuel capabilities, storage, emissions and zoning limitations, and alternate fuel delivery modes was sent to the PPAs so that relevant alternate fuel data could be solicited from dual-fuel generators. Responses to the data request indicated that data regarding the applicable alternate fuel storage capacity and delivery modes were not available for many of the dual-fuel capable generators on the list due primarily to confidentiality restrictions.

In addition to the information received from the PPAs, LAI utilized data from public sources. The publicly available sources including: (i) air permits and permit applications, (ii) state commission and SEC filings, (iii) environmental agency documents, (iv) company reports, and (v) press releases. These data are reported for currently operating plants as well as for plants that are under development or those units that have been proposed and have since filed air permit or siting permit applications with federal, state, and/or local regulatory agencies.

The list of dual-fuel capable generators is provided as Exhibit 28. This list includes old-style steam turbine generators that typically utilize #6 FO for backup fuel. Other technology types include SC and CC plants that utilize distillate fuel oil for backup.[1] As discussed briefly in footnote 1, distillate fuel oil encompasses a variety of liquid fuels. The range of fuel delivery modes included oil pipeline, ocean-going tankers and barges, river barges, rail tank cars, and tank trucks.

The capacities of these fuel oil delivery modes vary considerably:

- Trucks typically provide 7,500 to 10,500 gallons per delivery.
- Rail tank cars typically have capacities of 20,000 to 30,000 gallons.
- River barge capacities typically range from 600,000 to over 1 million gallons.
- Ocean-going barges have capacities ranging from 4.7 million gallons to 9.4 million gallons.
- The typical Jones Act tanker can deliver up to 12 million gallons of liquid fuel.

A total of 561 dual-fuel capable units in the Study Region are included in the list. Table 11-1 includes a summary by backup fuel type for each PPA. The #6 FO capacity represents the alternate fuel capacity for dual-fuel capable steam turbine generators, such as those used in

[1] Distillate fuel oil includes number 2 fuel oil (#2 FO), ULSD, kerosene, and ultralow sulfur kerosene.

downstate New York along the New York Facilities System as well as in New England and parts of PJM, among other locations. The distillate oil capacity represent all types of distillate fuel oil utilized or proposed as the alternate fuel for SC and CC plants. Details regarding the ULSD market and availability, storage issues, as well as resupply modes and costs are covered in Section 11.4.

Table 11-1. Summary of Dual-Fuel Capacity by PPA and Alternative Fuel Type (MW)[2]

PPA	Installed Capacity	Total Oil Capacity	#6 FO Capacity	% of Installed Capacity	Distillate Oil Capacity	% of Installed Capacity
IESO	36,000	2,100	2,100	*6%*	0	*0%*
ISO-NE	33,600	6,772	2,731	*7%*	4,041	*11%*
MISO	179,900	18,949	5,915	*3%*	13,034	*7%*
NYISO	40,400	21,738	10,446	*26%*	11,292	*28%*
PJM	217,100	24,444	2,951	*1%*	21,463	*10%*
TVA	37,300	5,267	0	*0%*	5,267	*14%*
Study Region	544,300	79,270	24,143	*4%*	55,097	*10%*

11.2.2 Dual-Fuel Steam Plants

Many of the dual-fuel steam units are located on navigable water ways and can be resupplied by river barges, ocean-going barges, and, in some cases, tankers. In the Northeast, most of the dual-fuel steam plants can take barge or tanker deliveries through existing wharf facilities. These plants also tend to have much larger on-site #6 FO oil storage capacities as compared with amount of distillate storage capacity typically held at SC or CC plants.

Dual-fuel steam plants in inland locations or with restrictions on other delivery modes usually receive #6 FO by truck. Some dual-fuel steam units have traditionally been served by waterborne deliveries. Certain generators contacted by LAI reported that insufficient dredging of the waterways has made barge deliveries difficult and sometimes impossible, thereby forcing the plants to rely on truck deliveries. When those plants are required to operate at or near full load, refueling presents logistical problems given the large number and frequency of truck deliveries to meet the full load burn rate. Complicating the logistical problems is the type, age, and number of trucks used to deliver the #6 FO. Given declining refinery production of #6 FO, the low annual volumes of #6 FO required by steam plants and the growing transportation and electric generation markets for ULSD, much more tank truck capacity is dedicated to serving the ULSD market. As a result, #6 FO deliveries typically utilize the oldest equipment to serve that market, which cannot be used to supply ULSD due to fuel contamination problems.[3] The large storage

[2] This table includes existing plants and plants that are under development and scheduled to begin operation by 2018.

[3] Contamination occurs if the same trucks are used to deliver ULSD and #6 FO since the sulfur content of ULSD is limited to 15 ppm while the sulfur content, even for low sulfur (0.3%) #6 FO is 3,000 ppm.

capacities and #6 FO inventory at the dual-fuel steam units can mitigate this problem, except under unusual market conditions when these plants are dispatched to operate for comparatively long periods due to sustained higher than usual forced outage rates on conventional gas-fired generators, coal plants, and/or other generation units. The typical dual-fuel steam plant has on-site #6 FO storage equivalent to more than 550 hours of full load operation. Assuming the #6 FO inventory is full or nearly full going into the event, in LAI's view there is typically sufficient time to arrange for replenishing supplies to cover extended operating periods.

Table 11-2 provides storage capacity information and estimated full load hours of operation for several dual-fuel steam plants burning #6 FO, for which sufficient data was publicly available. The descriptive operating information shown in Table 11-2 is reasonably representative of the dual-fuel steam units operating elsewhere in the Study Region.

Table 11-2. Representative Dual-Fuel Steam Units – #6 Fuel Oil Data

PPA	Plant/Unit	Cap. (MW)	Storage Capacity (Gal)	Hours at Full Load	Resupply Mode
NYISO	Northport 1-4	1,589		195	Barge
NYISO	Port Jefferson 3,4	393		944	Barge
NYISO	Barrett 1,2	397	**REDACTED**	732	Truck
NYISO	Oswego 5,6	1,685		543	Barge
NYISO	Roseton 1,2	1,220		544	Barge
PJM	Chalk Point 3,4	1,318	29,525,000[4]	317	Pipeline / Barge[5]
IESO	Lennox 1-4	2,140	67,200,000	513	Rail (55 car unit train)
MISO	G. Andrus 1	741	77,700,000[6]	216	Barge

On Long Island, the Northport and Port Jefferson stations owned and operated by National Grid to serve the Long Island Power Authority (LIPA) receive barge deliveries of #6 FO. Port Jefferson has sufficient on-site storage to run at full load for 944 hours (39 days). In contrast, the larger Northport station has on-site storage for 195 hours (just over 8 days). The ability of Northport to utilize barge deliveries, with individual barges each capable of holding 1 million

[4] Plant connected by pipeline to storage terminal with an additional 63 million gallons of #6 FO storage which is shared with Morgantown 1 and 2.

[5] Chalk Point is served by an 11 mile pipeline from Piney Point Terminal that receives barges.

[6] The reported storage of 77.7 million gallons at the G. Andrus 1 plant would permit 1,617 hours of full load operation, but LAI understands that this includes inactive tanks. Assuming a target inventory of 9 days of full load operation, the effective storage would be approximately 10.4 million gallons, equivalent to 216 hours of full load operation. (Source: the Independent Auditor's Report on The Annual Management Review Audit of Entergy Mississippi, Inc. presented to The Mississippi Public Service Commission by Boston Pacific Company, Inc. December 20, 2012).

gallons or more, allows Northport to extend full load operation for more than 8 days.[7] The Barrett station receives #6 FO deliveries by truck. Existing on-site storage capacity is sufficient to meet Barrett's fuel requirements at full load for 30 days. This operating period would be extended by truck deliveries during that 30 day period. With sufficient #6 FO tank trailers available, almost all of the plant's daily fuel requirements could be supplied in a typical 16 hour delivery day.[8]

The Oswego and Roseton stations in Oswego and Orange Counties, New York are resupplied by barges. The increased volume of crude barged from Albany to New York harbor and the New Jersey refineries has tightened the availability of barges to deliver #6 FO anywhere in the region. The large storage capacities at these plant sites accommodate sufficient inventories to support continued unit operation, but have the potential to be stressed when there are significant delays in arranging for the scheduling of barges to restock depleted inventory.

The Chalk Point station in Prince Georges County, Maryland has on-site storage for 317 hours at full load operation. Chalk Point is connected by an 11 mile pipeline to the Piney Point Terminal. The Piney Point terminal can receive deliveries of #6 FO by barge and has an additional 63 million gallons of storage capacity which is shared with Morgantown 1 and 2.[9]

The Lennox plant in Greater Napanee, Ontario is served by unit trains which can deliver 30,800 barrels (1.29 million gallons) of #6 FO every two days.

Dual-fuel steam plants in New England account for 2,461 MW of generating capacity and have total #6 FO storage capacity of more than 130 million gallons, sufficient to provide an average estimated 739 hours at full load.[10] The majority of this dual-fuel steam plant capacity is located on the coast of Connecticut. Other dual-fuel capable units are located in NEMA/Boston, SEMA, New Hampshire and Southern Maine.

11.2.3 Simple Cycle and Combined Cycle Plant Backup Fuel Storage

Dual-fuel units involving CTs in either SC or CC configurations typically utilize distillate fuel oil when gas is not available or is otherwise priced above the cost of distillate. This happens for

[7] Northport's full load operation for 24 hours for 8 days or more represents a low probability event in light of HVDC transmission project additions linking Long Island to PJM and ISO-NE, the availability of natural gas on Long Island from Transco into Long Beach, from Iroquois into South Commack, as well as other infrastructure changes LIPA has implemented over the last decade.

[8] This assumes that at least two delivery bays are available in order to accommodate truck deliveries and associated unloading every 30 minutes,

[9] Morgantown 1 and 2 are steam units that burn primarily coal but can also burn #6 FO.

[10] Data for these plants which include Canal 1 and 2, Montville 5 and 6, Newington 1, and New Haven Harbor are aggregated to comply with confidentiality requirements. The aggregated data include units that burn only #6 FO but which are at the same site as the dual-fuel steam units and share the site storage capacity.

brief intervals during cold snaps or during pipeline outage contingencies. While some existing plants, particularly those located outside of non-attainment areas, have been able to burn higher sulfur diesel or kerosene, many of these existing units, along with most new dual-fueled SC and CC units, will burn ULSD as backup fuel to meet increasingly stringent emissions requirements. Some units burn ultra-low sulfur kerosene (ULSK) in lieu of ULSD.

Trucks are the most common mode for delivering distillate oil to dual-fuel SC and CC plants. Almost always, SC and CC plants with on-site storage capacity have much less on-site storage capacity than steam units. This is because SC and CC plants with on-site storage capacity have typically been permitted and commercialized more recently, while many of the dual-fuel steam turbine generators were built in the 1960s and 1970s, designed as intermediate cyclers, and permitted initially to run on oil, not natural gas. A few SC and CC plants located on navigable waterways can take delivery of ULSD by barge and a few others can be supplied by pipeline, usually from a large fuel oil storage terminal or refinery.

Tables 11-3 through 11-7 provide information regarding on-site storage of alternate fuel and the estimated number of hours operating at full load that this storage capacity could support. The selected units are broadly representative of dual-fuel SC and CC plants in each PPA. There were no dual-fuel SC or CC plants listed in IESO.

Table 11-3. ISO-NE Representative SC and CC Alternate Fuel Data

Plant	Cap. (MW)	Technology	Alternate Fuel	Storage (Gal)	Hours at Full Load	Resupply Mode
Lake Road	812	CC	Distillate		17	Truck
Waterbury	96	CT	ULSK		41	Truck
PSEG Power	150	CT	ULSD		29	Truck
Pioneer Valley	306	CC	ULSD/Biodiesel		68	Truck
EP Newington	540	CC	ULSD	**REDACTED**	31	Pipeline/Truck
NRG Meriden	530	CC	ULSD		43	Truck
GenConn Devon	380	CT	ULSD		363	Barge
Berkshire Power[11]	272	CC	Distillate		31	Truck
Kleen Energy	620	CC	ULSD		264	Pipeline

[11] Berkshire Power has been permitted since construction for dual-fuel operation. As of September 2014 Berkshire Power has not submitted the required emissions testing results to MA Department of Environmental Protection verifying it can meet the distillate operation emission limits.

Table 11-4. NYISO Representative SC and CC Alternate Fuel Data

Plant	Cap. (MW)	Technology	Alternate Fuel	Storage (Gal)	Hours at Full Load	Resupply Mode
Bowline 3	775	CC	ULSD		151	Barge
Caithness LI I	350	CC	Distillate		24	Truck
Caithness LI II	752	CC	ULSD		46	Truck
Carr Street	122	CC	Distillate	REDACTED	61	Truck
PSEG Bethlehem	893	CC	Distillate		196	Barge
Empire Gen	970	CC	Distillate		77	Truck
Astoria Energy	640	CC	Distillate		212	Barge
Astoria Energy II	660	CC	Distillate		212	Barge

Table 11-5. PJM Representative SC and CC Alternate Fuel Data

Plant	Cap. (MW)	Technology	Alternate Fuel	Storage (Gal)	Hours at Full Load	Resupply Mode
Doswell	850	CC,CT	#2 FO	15,200,000	264	Truck
Tenaska Virginia	885	CC	#2 FO	2,100,000	48	Truck
ODEC Louisa	600	CT	Distillate	2,000,000	99	Truck
Bellemeade	267	CC	#2 FO	50,000	3	Pipeline[12]
Gordonsville	240	CC	ULSD	5,000,000	336	Truck
Lady Smith	783	CT	#2 FO	5,400,000	78	Truck
Darbytown	336	CT	ULSD	6,250,000	172	Truck
Bear Garden	590	CC	ULSD	4,500,000	153	Truck
West Deptford	600	CC	ULSD	2,000,000	51	Truck
Darby	480	CT	ULSD	1,400,000	29	Truck
Richland Peaking	390	CT	Distillate	2,000,000	55	Truck
Dresden Energy	550	CC	ULSD	2,250,000	74	Truck
National	500	CT	Distillate	1,120,000	24	Truck
Greenville	200	CT	Distillate	400,000	51	Truck
Troy Energy	600	CT	Distillate	4,400,000	97	Truck
Garrison Energy	309	CC	ULSD	1,400,000	82	Truck

[12] Bellemeade has on-site storage sufficient for only 3 hours of full load operation but is connected by a 1 mile pipeline to more than 20 million gallons of distillate storage at the TransMontaigne Partners terminal in Richmond.

Table 11-6. MISO Representative SC and CC Alternate Fuel Data

Plant	Cap. (MW)	Technology	Alternate Fuel	Storage (Gal)	Hours at Full Load	Resupply Mode
Mankato Energy	375	CC	#2 FO	1,250,000	77	Truck
Fox Energy	600	CC	ULSD	1,000,000	31	Truck
Paris Gen	400	CT	Distillate	1,500,000	42	Truck
Elk River	211	CT	ULSD	600,000[13]	40	Truck
Exira	150	CT	Distillate	500,000	81	Truck
Junction Station	550	CT	Distillate	1,500,000	31	Truck
Comanche	308	CC	Distillate	2,100,000	116	Truck
Rock Gen	503	CT	Distillate	1,200,000	26	Truck

Table 11-7. TVA Representative SC and CC Alternate Fuel Data

Plant	Cap. (MW)	Technology	Alternate Fuel	Storage (Gal)	Hours at Full Load	Resupply Mode
Allen	456	CT	Distillate	8,000,000	40W/35S	Barge
Colbert	392	CT	Distillate	9,036,000	68W/40S	Barge
Gallatin	600	CT	Distillate	10,626,560	100W/60S	Barge
Johnsonville	1128	CT	Distillate	23,030,000	100W/60S	Barge
Kemper	312	CT	Distillate	4,000,000	80W/60S	Truck
Lagoon Creek	1444	CT, CC	Distillate	6,000,000	56W/40S	Truck
Marshall	616	CT	Distillate	3,600,000	47W/40S	Truck
John Sevier	880	CC	Distillate	4,000,000	83W/93S	Truck

These data indicate a wide range of storage capacities at SC and CC plants relative to the number of hours each of these plants can run at full load.[14] A few plants have less than 3 days of full load storage on-site. The three days of full load storage is tantamount to 72 hours for CC plants and 48 hours for SC plants. Many plants do not have 5 days of storage on-site. Some of the plants that have more than 5 days of on-site storage were located adjacent to large storage tanks that served older steam plants and either had sufficient room to build large new ULSD storage tanks or could convert existing storage tanks to ULSD storage. Some plants apparently elected to construct larger storage tanks in response to market or economic conditions affecting gas pipeline deliverability conditions.[15] Plants capable of taking barge deliveries typically have larger on-site storage in order to take the larger quantities that barges carry. Also, some plants with small on-site storage capacity are located in close proximity to refineries or terminals that have much greater storage. For example, the Bellemeade plant in Virginia shows on-site storage

[13] Elk River has on-site storage capacity of 846,000 gal but is limited to 600,000 gal by permits.

[14] Assumes full tank going into the peak winter season.

[15] See Doswell, Darbytown, Gordonsville, and Bear Garden plants in Table 11-5; Kleen Energy in Table 11-3.

sufficient for only 3 hours of full load operation. However, the Bellemeade plant is connected by a 1 mile pipeline to more than 20 million gallons of distillate storage at the TransMontaigne Partners terminal in Richmond.[16]

Data on alternate fuel storage provided by TVA reflects its targets for on-site distillate inventories in terms of hours of full load operation at each plant for summer and winter operations. The estimated hours are based on target inventories that, in many cases, are lower than the storage capacity reported for each plant. For TVA, the target inventories as a percentage of on-site storage at each plant range from 20% to 90% for the summer season and from 26% to 98% for the winter season.

11.2.4 Dual-Fuel Emissions Issues and Conversion Limitations

The ability of SC and CC plants to burn backup liquid fuel is determined by local requirements governing transportation and bulk storage of liquid fuel, and by conditions incorporated in air operating permits. Local approvals are generally required for the construction of on-site distillate fuel storage tanks. Municipal or county health or environmental codes may prohibit bulk storage of oil or hazardous materials in areas where drinking water supplies may be vulnerable. State or local fire marshals commonly must review and approve plans for tank construction and siting. Tank siting and construction must meet local zoning requirements. Community concerns about increased tanker truck traffic have, in some instances, created challenges in obtaining zoning board approvals.

Air permits for new dual-fuel generators must comply with the New Source Review (NSR) and Prevention of Significant Deterioration (PSD) programs. The applicable requirements fall under either (i) federal NSR program, or (ii) the state's NSR (or equivalent) program. The permit requirements and operating limits that will be imposed on dual-fuel plants vary depending on several factors:

- Whether the facility is located in a county which is classified as "attainment" or "non-attainment" with respect to the National Ambient Air Quality Standards (NAAQS) for criterion pollutants. The criterion pollutants relevant to gas and distillate oil-fired electric generators are ozone, carbon monoxide, sulfur dioxide (SO_2), and particulate matter (PM_{10} and $PM_{2.5}$). NO_x is a precursor of ozone in the atmosphere; therefore NO_x emissions controls are included in NSR permit conditions. Within the states comprising the Ozone Transport Region (OTR), CT, DE, MA, MD, ME, NH, NJ, NY, PA, RI, VT, and northern VA, NO_x is treated as a non-attainment air pollutant regardless of the ozone attainment status of the individual OTR jurisdiction. States in the OTR or otherwise containing non-attainment counties must develop State Implementation Plans (SIPs) to improve air quality or prevent backsliding.

- Under the PSD program, carbon monoxide (CO) emissions limits for new combustion turbine generators in areas in attainment for CO may include unit operating hour

[16] This oil product pipeline is owned by Dominion Energy, but is operated by TransMontaigne.

restrictions, or if potential CO emissions exceed the applicable significant emission threshold, the unit may be subject to a Best Achievable Control Technology (BACT) analysis. The BACT analysis requires consideration of CO emission control technologies and in many recent air permits for CC and CTs has required installation of an oxidation catalyst system to limit CO emissions.

- If the annual emissions of the criterion air pollutants, on a “potential to emit” basis, exceed certain threshold quantities, the plant is considered a “major source” and must meet federal program requirements. Plants which emit less than the threshold quantity fall under state facility permit programs. State facility permit requirements may be more stringent than the federal NSR program.

Both major source and state facility permit programs are generally administered by individual states. Importantly, permit requirements vary from state to state, depending not only on the NAAQS attainment status, and whether it falls under minor source or state facility rules, but also on each state’s SIP, state regulations, and other state policy goals.

Major source permits in attainment areas fall under the PSD program, which requires the application of BACT. Many states also apply the BACT standard for state facility permits. BACT applied to recent air permits requires selective catalytic reduction (SCR) for NO_x control and a CO catalyst for gas-only and dual-fuel CC and for aeroderivative CTs.[17] SCR has not typically been BACT for frame SCs units, but this may become a future requirement as BACT evolves.

Major permits in non-attainment areas fall under Non-Attainment NSR program (NA NSR). NA NSR requires the application of the Lowest Achievable Emission Rate (LAER). Many states also apply LAER for their respective minor permit programs. While LAER is intended to be more stringent than BACT, in practice the emission control technologies are essentially identical to BACT. NA NSR also requires the facility to obtain emission offsets (also referred to as Emission Reduction Credits, or ERCs) for the non-attainment pollutant(s) from a facility that has either ceased operations or otherwise permanently reduced its emissions of a criterion pollutant. Depending on the pollutant, location, and state rules regarding trading between locations, ERCs may be readily available or scarce.

Typical operation on distillate fuel oil can produce significantly higher emissions of NO_x, particulate matter, and CO_2 than operation on natural gas. Permits for dual-fuel plants are therefore typically written with a limit on the annual hours of operation on distillate fuel oil, or in some cases, a gallon per year limit. The most common limit is 720 hours per year of full load operation on distillate fuel, although there are some older plants with higher hourly limits or without any annual limits. Some permits specifically allow distillate fuel oil use only when natural gas is curtailed, subject to the annual hourly limit. Some recent permits allow only 500 hours of operation on ULSD, and only during gas curtailment. Since the efficiency of emission

[17] BACT also applies to CO_2, but the standard has not required post-combustion emission controls for this pollutant on gas-fired plants.

control equipment can be impaired at part-load operation, some recent dual-fuel air permits also prescribe a minimum allowable load.

In addition to limits on annual operating hours on distillate oil, some permits prohibit use of distillate fuel during the ozone season (May 1 through September 30). The most stringent permit limit that LAI has encountered is 480 hours per year on distillate fuel oil.[18] LAI is not aware of any air permit for a power plant that contains explicit provisions to allow exceedances of the annual oil burn limit in the event of an emergency declared by a state or federal authority.[19]

Before the use of ULSD became increasingly common, the fuel sulfur content and the resulting SO_2 emissions when that fuel was burned had a large impact on setting the annual operating limits on distillate fuel oil. The driving force behind requiring the use of ultra-low sulfur fuels (15 ppm or less), usually ULSD, has been to reduce SO_2 emissions. Because sulfur-containing compounds, *e.g.*, mercaptan, are added as a safety odorizer to natural gas, switching to ULSD actually decreases SO_2 emissions. However, since burning ULSD still results in higher emissions of NO_x and particulates than burning natural gas, relatively low annual operating hour limits remain common in air permits for dual-fuel SC and CC plants.

Converting an existing gas-only plant to dual-fuel operation requires an air permit modification. An air permit modification is considered "major" if operating the plant on distillate oil would cause a net emissions increase that exceeds a "significance level," which is defined by regulation. A major modification would reopen the BACT or LAER review, and therefore upgrades to emission controls and/or more stringent operating restrictions may be required.[20] An operator who opts to restrict annual operations to remain below the significance levels may avoid requirements to upgrade equipment. The net emissions analysis generally must compare actual historic emissions to projected future emissions of the plant. In estimating projected future emissions, the applicant would consider the number of days when gas curtailment is expected.

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[18] Garrison Energy Center. State of Delaware Department of Natural Resources and Environmental Control, Secretary's Order No. 2013-A-0013.

[19] If an exceedance of the annual oil burn limit is anticipated in response to a PPA request, generators may seek emergency waivers from the applicable permit authority. Alternatively, the generator may document a deviation from permit conditions with a justification, which may provide an affirmative defense, depending on state regulations. Regulations promulgated under the Clean Air Act (40CFR 52.21) also allow generators to avoid triggering a major modification under NSR if the change in the method of operation is "use of an alternative fuel or raw material by reason of an order under sections 2(a) and (b) of the Energy Supply and Environmental Coordination Act of 1974 (or any superseding legislation) or by reason of a natural gas curtailment plant pursuant to the Federal Power Act."

[20] Physical modifications at existing dual-fuel plants can also trigger changes in operating conditions specified in the facility's air permit. For example, the Essential Power Operating Company in Lakewood, NJ, a CC with 2 Alstom 11NM turbines, proposed replacing the turbine compressor, turbine blades and vanes, which resulted in a reduction of the allowable hours on oil-fired operation from 5,957 to 480 per year. (NJ DEP, Air Pollution Control Operating Permit, Significant Modification and Preconstruction Approval, January 23, 2013.)

The significance level depends on the pollutant and whether the plant is located in an attainment or non-attainment area. The significance levels for attainment areas are shown in Table 11-8.

Table 11-8. Significance Levels for NAAQS Attainment Areas

Pollutant	Significance Level (tpy)
NO_x	40
SO_2	40
PM 10	15
VOCs	40
CO	100

The significance levels for non-attainment areas vary with the severity of the non-attainment, and may be different from state to state. For CTs and CCs equipped with SCR, the increase in NO_x emissions when converting from gas-only to dual-fuel may exceed the significance level, even if ULSD use is limited to 720 hours per year or less. The net increase in particulate matter emissions may also trigger a major modification, since the particulate emission rate when burning ULSD may be 3-4 times the rate from burning gas. A major modification in a non-attainment area may also trigger the need to obtain ERCs.

There are two other concerns arising from conversion of an existing gas-only plant to dual-fuel: compliance with local zoning requirements and the technical feasibility of retrofitting the facility. Gas-only plants typically obtain the necessary zoning permits and authorizations without requiring on-site fuel storage tanks or obtaining permission for truck deliveries that would increase or disrupt local traffic patterns. These approvals can be difficult to obtain during the normal permitting process for new plants; retroactively obtaining such approvals would be significantly more difficult.

Retrofitting an existing gas-only plant to provide dual-fuel capabilities may or may not be technically feasible, depending on the site footprint and layout. Retrofitting involves adding liquid fuel storage tanks, a truck receiving bay, liquid fuel handling / forwarding / heating / atomizing systems, new or expanded demineralized water tanks (for NO_x control) and associated systems, adding dual-fuel combustor nozzles, a new instrumentation and control system, and installing different or additional SCR catalyst(s). The SCR reactor vessel may also need to be retrofitted to accommodate the additional catalyst and ensure adequate treatment of exhaust gases. The additional land requirement for the oil and water storage tanks, truck receiving bay, and associated equipment is probably about two acres.[21] As discussed in Section 11.3, the incremental costs for this equipment is on the order of \$25-\$30 million for a new SC (frame CT) plant or a CC plant, and about one-half of that cost for a new SC (aero CT) plant. Retrofitting such equipment to an existing gas-only plant could easily be twice that amount or more, provided such conversion is feasible from local zoning and land-use perspectives. There are also additional compliance costs associated with developing an oil spill contingency plan, obtaining

[21] As explained in Section 11.3, a 3-day storage tank would require close to an acre, a demineralized water tank about one-half an acre, plus additional land for truck receiving bay.

regulatory approvals, acquiring spill response equipment and maintaining training and maintenance records for fuel oil storage.

11.3 Dual-Fuel Operating Characteristics and Costs

11.3.1 Overview

11.3.1.1 Dual-Fuel Capability

A generating unit is considered to have dual-fuel capability if it can switch from firing natural gas as a primary fuel to firing a secondary (or backup) liquid fuel, typically ULSD, on short notice and for periods of up to several days without violating air permit restrictions. To support this capability, the generating unit must have:

- ready access to an on-site inventory of liquid fuel,
- the ability to replenish that inventory even under severe winter conditions before the inventory is depleted,
- the ability to switch fuel at the burners without coming off-line,
- the ability to efficiently and safely control combustion while switching fuels, and
- the ability to control emissions firing either fuel within the unit's air permit parameters.

To the extent any one of the aforementioned five criteria is impaired, a generator's ability to maintain fully functional dual-fuel capability would likewise be imperiled for purposes of fuel assurance.

11.3.1.2 Older Dual-Fuel Generators

There are many older, existing steam units in the Study Region that were designed with, or converted to, dual-fuel (gas and oil) capability.[22] We note that many steam power plants were originally designed to operate on residual oil and later modified to operate on natural gas (delivered at pressures lower than required for SC and CC plants). In some instances, the capability to burn residual oil has been retained, but its use is often limited by air emission limitations. Evaluation of older SC and CC plant designs is also outside the scope of the Target 4 analysis. We note that while older single-fuel plants could be converted to dual-fuel operation, there can be significant cost, permitting, land, and community factors making such conversions difficult to achieve.

11.3.1.3 Recent Dual-Fuel Generators

The vast majority of new, non-renewable generating capacity recently installed or announced in the Study Region is based on CT technology and designed to operate with natural gas as its primary fuel in either a SC or CC configuration with heat recovery steam generators (HRSGs) and steam turbine generators (STGs). Virtually all CT models are offered with optional dual-

[22] Evaluation of these units is outside the scope of the Target 4 analysis.

fuel capability to burn either natural gas or a liquid fuel (such as kerosene or ULSD), and to switch from one to the other fuel with minimal operating disruptions. We provide a summary of the most popular current models that have recently been installed or are newly announced, with an emphasis on the incremental capital and O&M costs associated with dual-fuel capability. Two aeroderivative CT models in SC configuration and two heavy frame CT models in SC and CC configurations have been evaluated. Performance differences between the two fuels are also noted.

In general, adding the capability to burn a liquid backup fuel for either an SC or CC plant involves five specific initiatives, as follows:

- modifying burners and adding equipment / systems to the CT units,
- modifying the plant instrumentation and control systems,
- adding liquid fuel receiving, storage, and handling systems,
- adding or expanding the water storage and treatment systems, and
- modifying the emission control systems.

Being able to burn liquid fuel entails a more complicated air permit process. This is because NO_x emissions are higher on liquid fuels than on natural gas. These air permits often set limits on the hours or days that liquid fuel can be fired in any year, and might restrict liquid fuel operation to the non-summer months. As discussed in Section 11.2.4, such air permit limitations generally require backup fuels with extremely low sulfur levels, such as ULSD. Moreover, the limitations may be stricter for sites in a NO_x non-attainment areas.

11.3.1.4 Dual-Fuel Costs

In addition to higher capital costs, dual-fuel capability requires higher fixed operating costs to maintain the additional equipment and systems and to carry the liquid fuel inventory.[23] ULSD is much more expensive on a $/MMBtu basis than natural gas, except during brief intervals when pipeline congestion such as that observed during the Polar Vortex cause daily delivered spot gas prices to run up in the extreme, *i.e.*, super-spike. Plant operating characteristics change as well. Even if gas deliveries are not interrupted or priced above ULSD (thus leading to fuel switching), regular testing of the ULSD systems raises annual fixed operating costs that are generally not recoverable. Running on ULSD results in different plant performance characteristics: on ULSD, a generator's heat rate increases, capacity decreases, accrual costs for CT major maintenance will increase, and other variable operating costs will increase as well. For example, NO_x allowance

[23] The cost of a liquid fuel inventory is typically treated as a capital cost in the initial financing of a new project. However, LAI treats fuel inventory as a fixed operating cost, *i.e.*, a carrying charge because (i) fuel inventory can be financed at lower cost than other capital categories, (ii) the value of a given fuel inventory volume can vary year to year with fuel prices, and (iii) the fuel inventory level can be managed on a seasonal basis.

costs and water treatment costs will increase on ULSD relative to natural gas. As we understand it, if a plant submits an energy bid based on liquid fuel and is dispatched by the PPA, the resultant increase in variable operating costs is generally recoverable.

In consultation with the PPAs, LAI has selected SC and CC configurations that are representative of recently installed and newly announced gas-fired plants across the Study Region. For each configuration, we have calculated the following changes in costs and operating characteristics:

- Incremental capital costs for key equipment, system additions / modifications, and land (for the liquid fuel and demineralized water storage tanks).
- Incremental fixed O&M costs for staffing, property taxes, equipment, and insurance.
- Incremental variable O&M costs for consumables and air emission allowances.
- Performance effects in terms of net output, net heat rate, demineralized water requirements, emissions, and maintenance accruals.

An example of our budgetary-quality incremental cost estimates for dual-fuel SC and CC plants is summarized in Table 11-9 below. Full details are provided in Exhibit 29. We have broken ULSD inventory out of plant capital, but retained the unit cost of ULSD used in the PJM CONE Study.

Table 11-9. Summary of Incremental Costs for Dual-Fuel Capability (2018 $)

Configuration	Simple Cycle		Combined Cycle
CT Type	Heavy Frame	Aeroderivative	Heavy Frame
Location	Cleveland, OH	Newburgh, NY	Cleveland, OH
Net Summer Capacity (gas)	385 MW	184 MW	651 MW
Capital Cost (excluding fuel inventory)	$54.41/kW *+ 5.8%*	$48.85/kW *+ 2.9%*	$27.29/kW *+ 2.3%*
Initial ULSD Inventory Cost	$15.58/kW	$14.92/kW	$9.56/kW
Fixed Operating Costs	$3.55/kW-yr *+ 18.7%*	$1.89/kW-yr *+ 7.8%*	$2.81/kW-yr *+ 6.4%*

11.3.1.5 Dual-Fuel Economics

Throughout most of the Study Region, excluding TVA, developers have not seen a significant economic advantage to building in dual-fuel capability. In MISO North/Central, MISO South, and a substantial portion of PJM, pipeline transportation constraints have not been frequent enough to deter generators' reliance on non-firm transportation arrangements. There are other market incentives affecting generators' risk tolerance as well, in particular, erosion of capacity revenue attributable to fuel constraints. Moreover, generators located behind the LDCs' systems are typically arranging local transportation services on a non-firm basis as well.[24] For merchant plant owners, that is, independent generation companies who derive operating income from the sale of energy, capacity and ancillary services into PPA administered markets, the resulting expected incremental net energy margin from liquid fuel operation during pipeline curtailment events may not justify the cost associated with permitting and maintaining liquid fuel capability. Under traditional cost of service regulation, utilities are reasonably assured full cost recovery of the fixed and variable costs ascribable to the liquid fuel option.

As shown in the Target 2 analysis, there are some areas across the Study Region where the frequency and duration of transportation deficits are moderate to high. Under the Reference Gas Demand Scenario "S0" pricing, these areas include the EMAAC and SWMAAC portions of PJM, Virginia, most of NYISO and all of ISO-NE, excluding the New Mystic Station outside Boston.[25] In these locationally constrained areas, dual-fuel capability may be a viable economic option.

In New York City and Long Island, however, the local utilities must comply with the following Local Reliability Rules established by the New York State Reliability Council (as of April 14, 2014):

- I-R3. Loss of Generator Gas Supply (New York City): "The *NYS Bulk Power System* shall be operated so that the loss of a single gas facility does not result in the loss of electric *load* within the New York City *zone*."

- I-R5. Loss of Generator Gas Supply (Long Island): "The *NYS Bulk Power System* shall be operated so that a loss of a single gas facility does not result in the *uncontrolled loss of electric load* within the Long Island zone."

These Local Reliability Rules are intended to protect reliability in New York City and Long Island during both pipeline outage contingencies as well as periods of relatively high load. To implement these rules, Con Edison and LIPA have developed "Minimum Oil Burn Procedures" that require the gas-fired generators in New York City and on Long Island which have dual-fuel capability to co-fire specific units with liquid fuel under certain system loading conditions.

11.3.2 Combustion Turbine Models

CTs are generally categorized as either aeroderivative or "heavy" industrial frame models. Aeroderivative models were derived from jet or turbo-prop engines originally developed for

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[24] Fuel assurance objectives remain a work in progress and are presently under technical review by PJM, NYISO and ISO-NE. Potential tariff reform to increase penalties levied on capacity and/or energy sales due to fuel constraints may be implemented in 2018 and 2023, but have not been considered in the Target 4 analysis.

[25] The New Mystic combined cycle plant is a full requirements customer of the Suez Distrigas LNG import terminal, which maintains sufficient inventory under long term contract to ensure sufficient fuel supply to meet the New Mystic station's daily gas requirements.

aviation. Heavy frame models were originally designed for stationary use. Their lineage is traced to steam turbines. In principle, they operate the same way: a compressor pushes air into a combustion section, where fuel is injected under pressure and ignited. The high pressure, high temperature exhaust gas then flows through a set of turbine blades that drives a shaft to power the compressor and an external generator. Heavy frame CTs utilize a single shaft for the compressor and generator. Aeroderivative CTs often utilize separate shafts that operate at different speeds.

Today, aeroderivative CTs generally serve the smaller end of the utility grid generation market with unit capacities up to about 100 MW. Heavy frame CTs range from about 100 MW to over 300 MW per unit.[26] On a unitized basis, that is, dollars per kilowatt installed, aeroderivative units tend to be relatively expensive, but nevertheless have certain operational advantages, *i.e*., multiple start/stops, high efficiency, fast response, and operating flexibility. The high efficiency of recent aeroderivative models results in low exhaust temperatures in the 800°F range. The heavy frame units offer lower unit costs at some sacrifice in efficiency and flexibility, with exhaust temperatures above 1,000°F, leaving more energy in the exhaust that can be captured in a CC configuration. The energy embedded in the exhaust would otherwise be wasted in a SC configuration. Over the last decade, there has been steady technology progress regarding manufacturers' ability to improve the operational flexibility of heavy frame units in response to new operational challenges.[27]

There are many manufacturers of CTs world-wide. However, the market for grid-based power applications in North America is mostly supplied by a few vendors. GE is the largest manufacturer, having provided a majority of the gas-fired capacity installed in North America. GE offers heavy frame units through its Power Generation Products business area and aeroderivative units through its Distributed Power group. Siemens AG, a German company, also offers heavy frame units manufactured in Florida. The dominant Siemens models are derived from Westinghouse technology, as are the heavy frame units offered in North America by Mitsubishi Heavy Industries, a Japanese company. Rolls-Royce Holdings Plc, a world leader in aircraft engines, also markets an aeroderivative line in North America that Siemens AG is in the process of acquiring.[28] While there are several other CT manufacturers, their respective product slates are targeted mostly for the marine, pipeline compressor, industrial, and co-generation markets.[29]

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[26] Aeroderivative CT units are also commonly used in industrial and institutional combined heat and power installations which are not covered by this analysis.

[27] Increased cycling duty coupled with faster response in light of the increased penetration of intermittent resources has heightened pressure on manufacturers to improve the operational flexibility of the heavy frame units.

[28] Siemens issued a press announcement in May 2014 that it will acquire the Rolls-Royce Energy gas turbine and compressor business and enter into a long-term technology partnership. The transaction is expected to close by year-end.

[29] Solar Turbines, for example, has many CT packages in the 1-30 MW size range specifically for pipeline compressor applications.

For the purposes of the Target 4 study, LAI has focused on the following CT models from GE and Siemens to cover SC configurations from about 50 MW to 200 MW and CC configurations in the 300 to 600 MW range.

11.3.2.1 Aeroderivative CTs

GE LM6000 – The GE LM6000 aeroderivative CT is offered in several models ranging in nominal output from 43 MW to 56 MW. For simple cycle peaking operation, one of the most common is the LM6000-PC Sprint at 50.3 MW. The LM6000 has been offered in various forms since 1997, during which time its performance has been improved almost continuously. The US operating fleet consists of about 700 units. (See brochure provided as Appendix 35.)

GE LMS100 – The GE LMS100 CT is a relatively new (2005) offering which combines some features of aeroderivative units with features of heavy frame units. With 55 units installed worldwide, it has caught on rapidly for SC peaking applications due to high efficiency (attributable in large part to an innovative intercooler in the compressor section), operating flexibility, compact footprint, and convenient rating at about 100 MW. (See brochure provided as Appendix 36.)

11.3.2.2 Heavy Frame CTs

GE 7F.05 – The 7F.05 heavy frame gas turbine is the current version of GE's 7F series of CTs which have been produced over the last 20 years.[30] It has a nominal output of 216 MW and can be used in either SC or, more typically, CC configurations. In a typical 2x1 (2 CTs and 1 STG) CC configuration, the rated net output is approximately 641.5 MW. GE has sold over 1,100 F-class CTs globally. (See brochure provided as Appendix 37.)

Siemens SGT6-5000F – The Siemens SGT6-5000F heavy frame CT is derived from the Westinghouse 501F model and has a nominal ISO rating (with dry, low NO_x combustors) of 196 MW. In a 2x1 CC configuration, the rating is 588 MW. (See brochure provided as Appendix 38.)

11.3.3 Incremental Dual-Fuel Scope of Supply

The added scope items to provide dual-fuel capability, relative to gas firing only, is divided between items that would be provided with the turbine vendor's scope of supply and those that would be part of the balance of plant. Each scope of supply is described below.

[30] Some sources refer to the 7F.05 as the 7FA. The Gas Turbine World 2012 GTW Handbook lists 2 entries for the 7FA, one with a rating of 184.9 MW and the other at 215.8 MW. The lower rating corresponds to the model now labeled by GE as the 7F.04.

11.3.3.1 Combustion Turbine Vendor Scope Elements

The incremental scope items for dual-fuel capability vary among turbine vendors. In general, they include fuel oil manifold, combustor nozzles, fuel filtration equipment, atomizing air equipment, and various controls. LAI relied upon GE for most of the vendor scope differences between a single-fuel and dual-fuel 7FA.05 unit.

Dry Low NO_x (DLN) Dual-Fuel Combustion System – The DLN combustion system uses staged combustion and lean pre-mixed fuel and air, in which fuel and air mixing occurs prior to the combustion zone during gas operation. This minimizes the formation of NO_x during combustion. With liquid fuel injection, which occurs in diffusion mode, the fuel and air mixing occurs in the combustion zone. While efficient, diffusion mode operation results in higher NO_x emissions, thus water injection is used for NO_x abatement while operating on liquid fuel.

DLN Water Injection Skid for Liquid Fuel – The water injection system consists of pumping and metering equipment for supplying water to the combustion system for NO_x emission control during liquid fuel operation. The on-base equipment includes water supply manifold(s), instrumentation, and a piping connection to the off-base water supply. The off-base skid consists of a strainer/filter, pump, instrumentation, valves, and a connection to the customer's demineralized water supply system.

Main Liquid Fuel System & Atomizing Air Skid – The liquid fuel system delivers fuel oil from the fuel forwarding system to the turbine's combustion chambers. The system filters the fuel and controls the fuel flow to each nozzle in the combustion chambers. Major components include the main fuel pump, stop valve, fuel filter, flow divider, purge system, and atomizing air system components (used to atomize the liquid fuel prior to combustion).

Liquid Fuel Forwarding Skid – This system consists of low pressure pumps, filters, and valves necessary to deliver the liquid fuel from the storage tank to the main liquid fuel system.

Liquid Fuel Heater Skid – The fuel heater skid contains the electric fuel heater and controls required to preheat the liquid fuel before it is delivered to the main liquid fuel system.

Liquid Fuel Fire Detection – All skids containing liquid fuel handling and supply are equipped with fire detection instrumentation.

Liquid Fuel Recirculation System – During gas operation, the liquid fuel system can be charged and ready to operate on short notice if the gas pressure drops or the operator initiates a transfer. The system circulates liquid fuel to ensure readiness for operation. The system also provides a maintenance benefit by cooling the on-base components of the liquid fuel system, which prevents coking of the components. Coking involves a build of carbon residue on parts of the CT fuel oil path when distillate fuel is exposed to high enough temperatures for it to thermally decompose.

Liquid Fuel Automated Nitrogen Purge – This optional system preserves the liquid fuel system when it is not required by evacuating liquid fuel from the hot environment (piping and valves) inside the turbine enclosure to minimize coking opportunities. It also eliminates any requirement to exercise liquid fuel system to maintain transfer reliability. This system can be installed with the Liquid Fuel Recirculation System and used on a seasonal basis or when backup fuel operation is not required.

Mk VIe+ Controls for Liquid Fuel – Additional CT instrumentation and controls logic is required for dual-fuel operation, including control of the fuel pumps, liquid fuel stop valve, water injection pump and valves, monitoring of differential pressure across the filters, pump supply and discharge pressures, servo motor operation, protective action when a fault occurs, and to define the prerequisites (also referred to as "permissives") that allow transfer from gas to liquid fuel and from liquid fuel to gas.

The CT scope of supply for other large frame models is similar but differs in one respect for most aeroderivative CTs. When intended for peaking purposes, most aeroderivative CT units use water injection for NO_x control when operating on natural gas, since this provides additional generation capacity at relatively low cost (with some heat rate penalty). Hence, there is no need to include water injection equipment in the dual-fuel capability scope addition.

11.3.3.2 Combustion Turbine Balance of Plant Scope Items

Items that are normally treated as balance of plant and are generally common to all models are discussed below.

Liquid Fuel Receiving Facilities – A receiving station with connections, valves, and piping to safely off-load liquid fuel from delivery trucks (or in some instances, rail cars or barges) to a storage tank must be provided, along with systems to contain any spills and space for waiting vehicles. ULSD is generally delivered in 10,000 gallon semi-trailer tank trucks, and multiple deliveries per hour may be required during a cold snap or pipeline outage. A 650-MW CC plant at full load would require deliveries of about 735,000 gallons per day, or 74 truckloads, possibly confined to a 16-hour delivery period. For a plant of this size, the receiving facility would have to be able to accommodate two trucks unloading simultaneously, while accommodating additional trucks waiting to unload. Requirements for smaller plants, *e.g.*, a 100-MW aeroderivative SC facility would be less demanding, at about 14 truckloads per day.

Liquid Fuel Storage Tanks – The tankage volume to store enough fuel inventory for 3 days of full-load operation for a 650 MW CC plant is substantial – about 2.2 million gallons.[31] The tank would be surrounded by a concrete retaining basin to hold the full volume in the event of a tank failure, for a total footprint of about 39,000 square feet, just

[31] This 3-day oil storage tank assumption is only applicable to the analysis described in this section; we calculate multiple oil storage sizes in Section 11.6.5 based on site-specific factors, as discussed later in this report.

under one acre.[32] Distillate fuel tanks are generally pre-engineered structures of welded steel plate. In MISO North/Central, PJM, NYISO and ISO-NE, storage tanks would likely be equipped with thermal insulation and some form of heating system to keep the fuel temperature above 24ºF. Thermal insulation avoids waxing, while maintaining fuel viscosity within CT vendor specifications. It also serves to minimize the potential for contamination from water condensation. LAI developed a model structure to estimate the cost for fuel storage tanks.[33] See Appendix 39 for the basis for the model structure.

Liquid Fuel Forwarding Pumps and Related Piping – Pumps are required to move fuel from the storage tanks to the fuel skid in the power plant. While transfer pumps are often provided as part of the CT dual-fuel package, additional pumping may be necessary, depending on distance and elevation of the storage tanks. Piping generally includes lines in both directions between storage and the CT unit to accommodate recirculation and is generally heat-traced to facilitate flow and to keep delivered fuel within CT specifications on temperature and viscosity.

Demineralized Water System – All CC plants require demineralized water for boiler make-up and other uses, regardless of the fuel choice or NO_x control method. The hourly boiler make-up water requirement for a 650 MW CC plant firing natural gas and using DLN combustors is about 19,000 lb/hr, equivalent to 2,300 gal/hr. When firing ULSD, water injection would be required for NO_x control, bringing the hourly requirement up to 350,000 lb/hr or 42,000 gal/hr. While the CC plant might be designed with permanent demineralization capacity to support the boiler make-up requirement, a much greater water storage capacity along with provisions for temporary trailer-mounted demineralization capacity would be required for liquid fuel operation.[34] A demineralized water tank with 3 days of storage would have a volume of about 3.0 million gallons. A raw water storage tank might also be required if the plant site has a limited delivery rate for raw water, but LAI did not include a raw water storage tank in our cost estimates. All of these water tanks and systems would require winterization to prevent freezing. The demineralized water tank would occupy about 13,000 square feet of land, not including a spill containment structure, which may or may not be required.

Aeroderivative SC plants in peaking service generally use water injection for NO_x control on either natural gas or liquid fuel, since the water provides for additional mass flow and output capability, as noted earlier. Due to their intermittent operation, SC plants normally rely on stored demineralized water and trailer-mounted demineralizer capacity. The amount of demineralized water required for liquid fuel operation is only slightly

[32] Assumes 100 ft diameter, 40 ft high cylindrical welded steel tank and square containment area with an 8 ft high dike wall.

[33] The storage tank model structure and assumptions are based in part on a September 2006 report for the New York State Energy Research and Development Authority by ICF Consulting LLC and Applied Statistical Associates.

[34] Mobile demineralized water capacity is discussed in more detail in Appendix 40.

greater than for natural gas operation, so no significant incremental water-related equipment is required for dual-fuel capability.

<u>Post-Combustion Emission Controls</u> – Virtually all new CC facilities are equipped with SCR systems to reduce NO_x emissions in the stack exhaust to levels of about 2-2.5 parts per million (ppm) when firing natural gas when used in combination with either DLN or water injection at the burners. The SCR catalyst is installed as an integral part of the HRSG at a point where exhaust gas temperature is optimum for the catalyzed reaction of injected ammonia to minimize NO_x. Air permits for new CC plants typically require control to these levels on natural gas, but for dual-fuel units, higher emission concentrations may be allowed for a limited number of hours per year.[35] A plant designed for 9 ppm NO_x at the gas turbine exhaust flange and 2-2.5 ppm at the stack when firing natural gas will typically achieve 42 ppm with water injection at the turbine exhaust flange and 5 ppm at the stack after SCR when firing ULSD. Hours of operation on ULSD might be limited to 720 per year, with further restrictions on summer operation. The SCR system for a dual-fuel unit would not be significantly different than one for a gas-only unit. Recently, however, we were informed by vendors that they have been asked by CC developers in response to regulatory inquiries to reduce emissions when firing ULSD to levels closer to those achieved on natural gas, which would likely result in larger SCRs (to increase the catalyst surface area) and higher ammonia injection rates.

The application of SCR to SC plants is a more recent development, made possible by the development of NO_x catalysts that can operate at higher exhaust temperatures. This is because SC exhaust is not cooled in the high temperature sections of an HRSG as it would be in a CC plant. Some recent aeroderivative CT installations, particularly in non-attainment areas such as New York City, include SCR modules operating at up to 900°F and achieving stack concentrations of NO_x in the single digit range. The high (above 1000°F) exhaust temperatures on heavy frame CTs have typically prevented the use of SCR, consistent with the 2013 NYISO ICAP Demand Curve analysis by NERA that proposed heavy frame (Siemens SGT6-5000F) CT peakers without SCR as a reference plant for NO_x attainment zones upstate, but proposed LMS100 units with SCR in non-attainment zones, *i.e.*, Long Island, New York City, and the Lower Hudson Valley.[36] A subsequent report by the Brattle Group, however, found that SCR on heavy frame CTs was commercially available and recommended adopting that technology for the non-attainment zones.[37] These reports did not specifically address the impact of ULSD firing, but the CTs for the non-attainment zones were described as dual-fuel capable. According to GE, the SCR system design for heavy frame CTs includes specialized high temperature

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[35] Recent air permits for dual-fuel CCs may specify emission rate and/or ramp time limits during start-up and shut-down as well, creating additional operating constraints.

[36] "Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator", NERA Economic Consulting, August 2, 2013.

[37] "Independent Evaluation of SCR Systems for Frame-Type Combustion Turbines – Report for ICAP Demand Curve Reset", The Brattle Group, November 1, 2013.

catalysts and the introduction of dilution air into the exhaust upstream of the catalyst to reduce temperature to about 900°F.

11.3.4 Incremental Capital Cost for Dual-Fuel Capability

LAI estimated the incremental capital costs based on information provided by the CT manufacturers identified above and on the following CONE studies and FERC filings:

- "Cost of New Entry for Combustion Turbine and Combined Cycle Plants in PJM", by the Brattle Group and Sargent & Lundy, May 15, 2014. This 2014 PJM CONE Study provided capital and O&M cost data for GE 7FA units in SC and CC applications located in five regions. The Study assumed that SCs would be dual-fueled in every region except the Rest of RTO and CCs would be dual-fueled except for SWMAAC and Rest of RTO. Data for gas-only and dual-fueled units allowed LAI to estimate the incremental cost of dual-fuel capability. The Study provided relative cost factors for labor and other components across all included regions.

- "Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator", by NERA and Sargent & Lundy, August 2, 2013. This 2013 NYISO Demand Curve Study included capital cost and O&M costs for gas-only and dual-fuel SC and CC plants throughout New York.[38] The Study considered the Siemens SGT6-5000F (Zones A-F) and the GE LMS100 (Zones G-K) units for SC applications and the Siemens SGT6-5000F unit for CC applications (all Zones). (The SC model choices were revised later to reflect the availability of high temperature SCR that would allow the Siemens SGT6 SC-5000F to operate in all zones.) The Study identified the incremental cost of dual-fuel capability in Zones G-K for an LMS100 peaking station and a SGT6 CC station. It also provided relative cost factors for labor and other components across all zones.

- "Filing of Midcontinent Independent System Operator, Inc. Regarding LRZ CONE Calculation; FERC Docket No. ER13-2187-000", August 16, 2013. This Filing contained total capital costs per kW for SC plants located in MISO's southern region. MISO's Filing in FERC Docket No. ER12-2580-000 of September 4, 2012 contained similar capital costs for SC plants in MISO's northern region. Both sets of capital costs were taken from a 2010 U.S. Energy Information Administration report (as discussed in the next bullet).

- The MISO Filings were based on capital cost data in "Updated Capital Cost Estimates for Electricity Generation Plants" prepared by the U.S. Energy Information Administration, November 2010. The 2010 Energy Information Agency (EIA) Report provided capital

[38] The 2013 NYISO Demand Curve Study also included forecasted operating revenues and financial factors to derive net CONE values that are not relevant to this EIPC assignment. Although the Study considered CC technology, the NYISO Tariff requires Net CONE to be based on peaking technology.

cost and O&M costs for advanced (F-class) CTs located in all 50 states. LAI was able to utilize the relative capital cost data in this 2010 EIA Report to broaden the geographic scope of our cost estimates for EIPC.

The CONE studies used somewhat different assumptions about the choice of CT models, number of units per site, construction timing / commercial operation date, and treatment of fixed and variable O&M costs. However, the CONE studies were generally consistent with regard to (i) considering both SC and CC plants in multiple zones, (ii) utilizing F-technology frame CTs for SC calculations unless prohibited due to air emissions in non-attainment zones, and (iii) utilizing F-technology frame CTs for CC calculations. LAI was able to develop a consistent set of capital and O&M costs in 2018 dollars based on these studies, assuming an average 2% annual inflation rate over the last several years to provide a consistent temporal basis. While equipment costs should be roughly the same at any location within the EIPC study footprint (which MISO refers to as the "law of one price"), construction costs, in particular, labor, can vary from one region to another. These labor variations are described by LAI in more detail in Section 11.6.6.3.

LAI broke down capital cost categories in the general format used in the 2014 PJM CONE Study, with breakouts for equipment costs, construction materials, and construction labor. Other components of the Engineer / Procure / Construct (EPC) and Owner-Provided Equipment categories are estimated using factors consistent with the assumptions of the 2014 PJM CONE Study, but allow for a wider range of regional variations for labor rates, land cost, and sales tax rates. As shown in Table 11-10 and Table 11-11, we have re-arranged some cost breakouts from the 2014 PJM CONE Study to facilitate our modeling, but the dual-fuel differential cost results are consistent.[39]

[39] CONE parameters included in PJM's tariff filings in Docket ER14-2940-000 on September 25, 2015, and in Docket ER15-68-000 on October 9, 2014 were not available at the time this study was undertaken.

Table 11-10. Capital Costs for 2x1 7FA CC from 2014 PJM CONE Study

	Base Location (PJM RTO)			Table references are to "PJM 2014 CONE Study" by Brattle Group
	Gas-Only	Dual-Fuel	Increment	Gas-Only source: Table 20, Rest of RTO column
Nominal $000 for 2018 CO				
Equipment Cost				
Gas Turbine Scope	$92,600	$97,300	$4,700	Dual-fuel source: Table 20, SWMAAC column
HRSG/SCR	$43,500	$43,500	$0	Dual-fuel source: Table 20, SWMAAC column
Other major equipment	$96,100	$96,100	$0	Dual-fuel source: Table 20, SWMAAC column, less $4,031 k for fuel, DW sys (1)
Materials	$37,800	$39,815	$2,015	Dual-fuel cost = Gas-only cost + $2,015 k for fuel, DW sys materials (1)
Sales Tax	$16,200	$16,603	$403	6.0% of subtotal for equipment and materials
Subtotal	$286,200	$293,318	$7,118	
Construction				
Construction Labor	$164,500	$166,515	$2,015	Dual-fuel cost = Gas-only cost + $2,015 k for fuel, DW sys labor (1)
Other Labor	$39,900	$39,900	$0	Dual-fuel source: Table 20, SWMAAC column
Subtotal for EPC Fee	$490,600	$499,734	$9,134	
EPC Fee	$58,872	$59,968	$1,096	12.0% of subtotal for EPC fee
EPC Contingency	$54,947	$55,970	$1,023	10.0% of subtotal for EPC fee + EPC fee
Total EPC Cost	$604,419	$615,672	$11,252	
Owner's Costs				
Development Costs	$30,221	$30,784	$563	5.0% of EPC total
Mobilization & Startup	$6,044	$6,157	$113	1.0% of EPC total
Electrical Interconnection	$21,400	$21,400	$0	Dual-fuel cost assumed same as Gas-only cost
Gas Interconnection	$22,600	$22,600	$0	Dual-fuel cost assumed same as Gas-only cost
Land	$1,524	$1,562	$38	Dual-fuel cost includes 1.0 additional acres at $38.1 k/acre
Non-Fuel Inventories	$3,022	$3,078	$56	0.50% of EPC total
Start up natural gas cost	$21,011	$21,011	$0	Based on Table 13 data for production and fuel consumption during testing
Start up distillate oil cost		$5,319	$5,319	Based on Table 13 data for production and fuel consumption during testing
Start up energy revenue	($24,735)	($26,346)	($1,612)	Based on Table 13 data for production and fuel consumption during testing
Distillate oil inventory		$5,319	$5,319	Fuel Oil price from Table 13, 72 hours storage assumed
Owner's Contingency	$7,298	$8,179	$882	9.0% of owner's costs above
Financiing Fees	$16,627	$17,154	$526	2.40% of EPC, owner's costs, and owner's contingency
Subtotal	$105,013	$116,216	$11,203	
Grand Total (Overnight)	$709,432	$731,887	$22,455	Dual-fuel overnight cost consistent with estimate in Table 29
Grand Total (Installed)	$777,183	$801,783	$24,600	1.096 x Overnight Costs (accounts for timing of expenditures)
			3.17%	
Installed $/kW of ICAP	$1,194	$1,232	$37.79	Based on summer Installed Capacity rating of 578.0 MW
				(1) Material and labor cost estimates for liquid fuel and demineralized water systems are explained elsewhere.

Table 11-11. Capital Costs for 2x7FA SC from 2014 PJM CONE Study

	Base Location (PJM Rest of RTO)			Table references are to "PJM 2014 CONE Study" by Brattle Group
	Gas-Only	Dual-Fuel	Increment	Gas-Only source: Table 19, Rest of RTO column
Nominal $000 for 2018 CO				
Equipment Cost				
Gas Turbine Scope	$94,000	$98,400	$4,400	Dual-fuel source: Table 19, SWMAAC column
HRSG/SCR	$17,900	$18,700	$800	Dual-fuel source: Table 19, SWMAAC column
Other major equipment	$25,500	$26,015	$515	Dual-fuel source: Table 19, SWMAAC column, less $4,485 k for fuel, DW sys (1)
Materials	$8,600	$10,842	$2,242	Dual-fuel cost = Gas-only cost + $2,242 k for fuel, DW sys materials (1)
Sales Tax	$8,760	$9,237	$477	6.0% of subtotal for equipment and materials
Subtotal	$154,760	$163,195	$8,435	
Construction				
Construction Labor	$55,300	$57,542	$2,242	Dual-fuel cost = Gas-only cost + $2,242 k for fuel, DW sys labor (1)
Other Labor	$18,600	$19,600	$1,000	Dual-fuel source: Table 19, SWMAAC column
Subtotal for EPC Fee	$228,660	$240,337	$11,677	
EPC Fee	$22,870	$24,034	$1,164	10.0% of subtotal for EPC fee
EPC Contingency	$25,150	$26,437	$1,300	10.0% of subtotal for EPC fee + EPC fee
Total EPC Cost	$276,680	$290,808	$14,141	
Owner's Costs				
Development Costs	$13,834	$14,540	$706	5.0% of EPC total
Mobilization & Startup	$2,767	$2,908	$141	1.0% of EPC total
Electrical Interconnection	$12,700	$12,700	$0	Dual-fuel cost assumed same as Gas-only cost
Gas Interconnection	$22,600	$22,600	$0	Dual-fuel cost assumed same as Gas-only cost
Land	$1,143	$1,181	$38	Dual-fuel cost includes 1.0 additional acres at $38.1 k/acre
Non-Fuel Inventories	$1,383	$1,454	$71	0.50% of EPC total
Start up natural gas cost	$10,589	$10,589	$0	Based on Table 13 data for production and fuel consumption during testing
Start up distillate oil cost		$5,109	$5,109	Based on Table 13 data for production and fuel consumption during testing
Start up energy revenue	($7,367)	($8,440)	($1,073)	Based on Table 13 data for production and fuel consumption during testing
Distillate oil inventory		$5,109	$5,109	Fuel Oil price from Table 13, 72 hours storage assumed
Owner's Contingency	$5,188	$6,098	$909	9.0% of owner's costs above
Financiing Fees	$8,148	$8,752	$603	2.40% of EPC, owner's costs, and owner's contingency
Subtotal	$70,986	$82,601	$11,615	
Grand Total (Overnight)	$347,666	$373,409	$25,756	Dual-fuel overnight cost consistent with estimate in Table 29
Grand Total (Installed)	$363,650	$390,577	$26,927	1.046 x Overnight Costs (accounts for timing of expenditures)
			7.40%	
Installed $/kW of ICAP	$945	$1,014	$69.94	Based on summer Installed Capacity rating of 385.0 MW
				(1) Material and labor cost estimates for liquid fuel and demineralized water systems are explained elsewhere.

LAI utilized the differential cost estimates in the 2013 NYISO Demand Curve Reset Study to identify incremental dual-fuel capability capital costs for a 2-unit LMS100 plant located in the Lower Hudson Valley, as shown in Table 11-12. As shown in Table 11-13 we restructured the study capital cost accounts to parallel the cost structure of the 2014 PJM CONE Study and applied escalation to express costs in 2018 dollars.

Table 11-12. Capital Costs for 2xLMS100 SC from 2013 NYISO Demand Curve Reset Study

Site	K - Long Island			J - New York City			G - Poughkeepsie			G - Newburgh		
Fuel Capability	Gas	Dual	Incr	Gas	Dual	Incr	Gas	Dual	Incr	Gas	Dual	Incr
Capital Costs (2013 $ 000)												
EPC Costs												
Equipment												
Equipment	$113,304	$116,520	$3,216	$114,626	$117,879	$3,253	$114,219	$117,461	$3,242	$114,219	$117,461	$3,242
Spares	$1,126	$1,126	$0	$1,126	$1,126	$0	$1,126	$1,126	$0	$1,126	$1,126	$0
Subtotal	$114,430	$117,646	$3,216	$115,752	$119,005	$3,253	$115,345	$118,587	$3,242	$115,345	$118,587	$3,242
Construction												
Construction Labor & Materials	$86,172	$88,655	$2,483	$92,904	$95,658	$2,754	$65,989	$67,367	$1,378	$70,810	$72,387	$1,577
Plant Switchyard	$4,516	$4,516	$0	$7,346	$7,346	$0	$4,619	$4,619	$0	$4,771	$4,771	$0
Electrical Interconnection & Deliverability	$9,980	$9,980	$0	$13,009	$13,009	$0	$10,047	$10,047	$0	$10,047	$10,047	$0
Gas Interconnect & Reinforcement	$5,395	$5,395	$0	$6,347	$6,347	$0	$5,395	$5,395	$0	$5,395	$5,395	$0
Site Prep	$4,047	$4,047	$0	$7,523	$7,523	$0	$3,292	$3,292	$0	$3,440	$3,440	$0
Engineering & Design	$11,245	$11,569	$324	$11,875	$12,227	$352	$10,220	$10,433	$213	$10,487	$10,721	$234
Construction Mgmt. / Field Engr.	$2,811	$2,892	$81	$2,969	$3,057	$88	$2,555	$2,608	$53	$2,623	$2,681	$58
Subtotal	$124,165	$127,054	$2,889	$141,974	$145,167	$3,193	$102,116	$103,761	$1,645	$107,573	$109,442	$1,869
Startup and Testing												
Startup & Training	$1,928	$1,928	$0	$2,038	$2,038	$0	$1,739	$1,739	$0	$1,787	$1,787	$0
Testing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal	$1,928	$1,928	$0	$2,038	$2,038	$0	$1,739	$1,739	$0	$1,787	$1,787	$0
Contingency	$23,014	$23,014	$0	$24,322	$24,322	$0	$20,752	$20,752	$0	$21,324	$21,324	$0
Subtotal - EPC Costs	$263,537	$269,642	$6,105	$284,085	$290,532	$6,447	$239,952	$244,839	$4,887	$246,029	$251,140	$5,111
Non-EPC Components												
Owner's Costs												
Permitting	$2,696	$2,696	$0	$2,905	$2,905	$0	$2,448	$2,448	$0	$2,511	$2,511	$0
Legal	$2,696	$2,696	$0	$2,905	$2,905	$0	$2,448	$2,448	$0	$2,511	$2,511	$0
Owner's Project Mgmt. & Misc. Engr.	$4,045	$4,045	$0	$4,358	$4,358	$0	$3,673	$3,673	$0	$3,767	$3,767	$0
Fuel Oil Testing	$0	$875	$875	$0	$871	$871	$0	$866	$866	$0	$866	$866
Social Justice	$539	$539	$0	$2,615	$2,615	$0	$490	$490	$0	$502	$502	$0
Owner's Development Costs	$8,089	$8,089	$0	$8,716	$8,716	$0	$7,345	$7,345	$0	$7,534	$7,534	$0
Financing Fees	$5,393	$5,393	$0	$5,811	$5,811	$0	$4,897	$4,897	$0	$5,023	$5,023	$0
Studies (Fin, Env, Market, Interconnect)	$1,348	$1,348	$0	$1,453	$1,453	$0	$1,224	$1,224	$0	$1,256	$1,256	$0
Emission Reduction Credits	$1,144	$1,144	$0	$1,144	$1,144	$0	$0	$0	$0	$0	$0	$0
Subtotal	$25,950	$26,825	$875	$29,907	$30,778	$871	$22,525	$23,391	$866	$23,104	$23,970	$866
Financing (Incl AFUDC, IDC)												
EPC Portion	$12,595	$12,595	$0	$13,571	$13,571	$0	$11,436	$11,436	$0	$11,731	$11,731	$0
Non-EPC Portion	$1,253	$1,253	$0	$1,438	$1,438	$0	$1,093	$1,093	$0	$1,120	$1,120	$0
Working Capital and Inventories	$2,676	$5,321	$2,645	$2,886	$5,519	$2,633	$2,428	$5,046	$2,618	$2,491	$5,109	$2,618
Subtotal - Non-EPC Costs	$42,474	$45,994	$3,520	$47,802	$51,306	$3,504	$37,482	$40,966	$3,484	$38,446	$41,930	$3,484
Total Capital Investment	**$306,011**	**$315,636**	**$9,625**	**$331,887**	**$341,838**	**$9,951**	**$277,434**	**$285,805**	**$8,371**	**$284,475**	**$293,070**	**$8,595**

Table 11-13. Capital Costs for 2xLMS100 SC in Format of 2014 PJM CONE Study

	Base Location (Newburgh)			References are to "NYISO 2013 Demand Curve Reset Study" by NERA
	Gas-Only	Dual-Fuel	Increment	Dual-Fuel source: Table A-3, Zone G (Newburgh) Column
Nominal $000 for 2018 CO				Escalation from 2013$ to 2018$ at 2.0%
Equipment Cost				
Gas Turbine Scope	$83,313	$86,658	$3,345	Gas-Only source: Allocation of Differential from Table A-3
HRSG/SCR	$15,472	$15,472	$0	Gas-Only source: Allocation of Differential from Table A-3
Other major equipment	$20,233	$20,233	$0	
Materials	$21,920	$22,575	$656	Dual-fuel cost = Gas-only cost + $656 k for fuel system materials (1)
Sales Tax	$9,866	$10,146	$280	7.0% of subtotal for equipment and materials
Subtotal	$150,804	$155,085	$4,281	
Construction				
Construction Labor	$54,726	$55,382	$656	Dual-fuel cost = Gas-only cost + $656 k for fue system labor (1)
Other Labor	$0	$0	$0	
Subtotal for EPC Fee	$205,530	$210,467	$4,937	
EPC Fee	$20,553	$21,047	$494	10.0% of subtotal for EPC fee
EPC Contingency	$22,608	$23,151	$500	10.0% of subtotal for EPC fee + EPC fee
Total EPC Cost	$248,691	$254,665	$5,931	
Owner's Costs				
Development Costs	$12,435	$12,733	$299	5.0% of EPC total
Mobilization & Startup	$2,487	$2,547	$60	1.0% of EPC total
Electrical Interconnection	$11,093	$11,093	$0	Dual-fuel cost assumed same as Gas-only cost
Gas Interconnection	$5,957	$5,957	$0	Dual-fuel cost assumed same as Gas-only cost
Land	$995	$1,061	$66	Dual-fuel cost includes 1.0 additional acres at $66.3 k/acre
Non-Fuel Inventories	$1,243	$1,273	$30	0.50% of EPC total
Start up natural gas cost	$9,296	$9,296	$0	Based on 982 hours of testing, $5.49/MMBtu
Start up distillate oil cost		$2,222	$2,222	Based on 72 hours of testing, $17.90/MMBtu
Start up energy revenue	($7,008)	($7,509)	($502)	Based on 1054 hours of testing, $38.70/MWh
Distillate oil inventory		$2,222	$2,222	Based on 72 hours of inventory, $17.90/MMBtu
Owner's Contingency	$3,285	$3,681	$396	9.0% of owner's costs above
Financiing Fees	$6,923	$7,182	$258	2.40% of EPC, owner's costs, and owner's contingency
Subtotal	$46,705	$51,757	$5,052	
Grand Total (Overnight)	$295,397	$306,422	$10,983	Dual-fuel overnight cost consistent with format of Table 29
Grand Total (Installed)	$309,790	$321,353	$11,563	1.049 x Overnight Costs (accounts for timing of expenditures)
			3.73%	
Installed $/kW of ICAP	$1,680	$1,743	$62.71	Based on summer Installed Capacity rating of 180.0 MW
				(1) Material and labor cost estimates for liquid fuel and demineralized water systems are explained elsewhere.

Our Cost Model focuses on the cost categories that are directly affected by the incremental scope items for dual-fuel capability. Other categories are either omitted or calculated as percentages of the direct cost accounts. We have taken the cost of fuel oil inventory out of the capital cost portion of the model, thereby treating oil inventory as an ongoing fixed operating cost. Capital costs include the costs of initial testing of the plant using ULSD as a fuel. Table 11-14 shows the resulting differential capital costs for the 7FA CC configuration in the selected base location (Cleveland as representative of PJM's Rest of RTO) and in selected zones in PJM. Tables for the 7FA CC, 7FA SC, and LMS100 SC covering a range of locations are provided, along with a tabulation of model variables, in Exhibit 29.

Table 11-14. Incremental Capital Costs for Dual-Fuel Capability for 2x1 7FA CC (Select PJM Zones)

Location	Base	RTO	EMAAC	SWMAAC	WMAAC	Dominion
Locational Assumptions	OH	OH	NJ	MD	PA	VA
Nominal Capital $MM for 2018 CO						
Gas Turbine Scope	$4.700	$4.700	$4.700	$4.700	$4.700	$4.700
Other major equipment	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
Other construction labor	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
Liquid Fuel, Demin water handling (Mat'l)	$0.900	$0.900	$0.900	$0.900	$0.900	$0.900
LIquid Fuel, Demin water handling (Labor)	$0.900	$0.900	$1.170	$0.887	$0.920	$0.804
Liquid fuel storage tank (Mat'l)	$0.827	$0.827	$0.846	$0.843	$0.825	$0.838
Liquid fuel storage tank (Labor)	$0.556	$0.556	$0.740	$0.559	$0.568	$0.504
Demin water storage tank (Mat'l)	$0.498	$0.498	$0.498	$0.498	$0.498	$0.498
Demin water storage tank (Labor)	$0.335	$0.335	$0.436	$0.331	$0.343	$0.300
Incremental Land for Tanks	$0.038	$0.038	$0.066	$0.074	$0.042	$0.054
Startup Testing ULSD	$5.087	$5.087	$5.244	$5.217	$5.070	$5.179
Startup Testing Energy Sales on ULSD	($1.611)	($1.611)	($1.812)	($1.647)	($1.605)	($1.636)
Inventory carrying cost as O&M	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
Total Incremental Direct Cost	$12.232	$12.232	$12.788	$12.362	$12.261	$12.142
Sales tax on equipment and materials	$0.416	$0.416	$0.488	$0.418	$0.413	$0.434
EPC Fee	$1.096	$1.096	$1.173	$1.096	$1.100	$1.077
EPC Contingency	$1.023	$1.023	$1.095	$1.023	$1.027	$1.005
Development Cost	$0.563	$0.563	$0.602	$0.563	$0.565	$0.553
Mobilization & Startup	$0.113	$0.113	$0.120	$0.113	$0.113	$0.111
Non-fuel Inventories	$0.056	$0.056	$0.060	$0.056	$0.056	$0.055
Owner's Contingency	$0.332	$0.332	$0.331	$0.343	$0.331	$0.339
Financing Fees	$0.380	$0.380	$0.400	$0.383	$0.381	$0.377
Indirect (factored) Costs	$3.977	$3.977	$4.271	$3.996	$3.986	$3.951
Total Overnight Cost	$16.209	$16.209	$17.059	$16.357	$16.247	$16.093
Total Installed Cost	$17.765	$17.765	$18.697	$17.928	$17.806	$17.638
Installed Cost per kW of ICAP	$27.29	$27.29	$27.99	$27.00	$27.44	$26.72

11.3.5 Incremental Fixed O&M Costs for Dual-Fuel Capability

Dual-fueled SC and CC plants face higher fixed O&M costs for maintaining additional equipment, incremental property taxes and insurance, periodic liquid fuel tests (net of offsetting energy revenues), and carrying costs of liquid fuel inventory. Based on information provided by CT manufacturers and data in the CONE studies, LAI estimated the incremental fixed operating cost for each of the selected plant configurations as tabulated in Table 11-15. Costs are presented in 2018 US dollars per year, assuming an average general inflation rate of 2% per year into the future. Labor and property tax costs can vary dramatically from one region to another, and can be estimated using regional factors.

Table 11-15. Incremental Fixed O&M Costs for Dual-Fuel Capability – Base Locations

CT Model and Configuration	2x1 7FA CC	2x7FA SC	2xLMS100 SC
Location	Base	Base	Base
Locational Assumptions	OH	OH	Newburgh
Annual Fixed O&M Cost (2018 $MM /yr)			
Materials & Contract Services	$0.118	$0.044	$0.011
Administrative & General Expense	$0.023	$0.047	$0.011
ULSD for Regular Testing	$1.060	$1.070	$0.491
Energy Offset for Testing	($0.336)	($0.223)	($0.116)
Property Taxes	$0.259	$0.303	$0.068
Insurance	$0.107	$0.126	$0.054
ULSD Inventory Carrying Cost as Fixed O&M	$0.203	$0.206	$0.094
Total Fixed O&M (2018 $MM/yr)	$1.435	$1.572	$0.612
Total Fixed O&M (2018 $kW-yr)	$2.20	$4.08	$3.32

For the purpose of model development, the cost of liquid fuel testing and carrying costs for liquid fuel inventory are based on a ULSD price of $2.52/gal, as used in the PJM CONE analysis, and assume an average inventory level over the year of 3 days full load operation. Regional variations in price and average inventory level will be developed in more detail in Section 11.6.5.

11.3.6 Operating Characteristics and Fixed Operating Costs for Natural Gas and for Liquid Fuel

The decision to design for or add dual-fuel capability to a new CT-based power plant fuel must consider the following components

- Incremental capital recovery for power island and balance-of-plant equipment and associated construction costs, as well as net costs (after power sales revenue) of pre-commissioning testing on liquid fuel

- Fuel inventory carrying costs and other incremental fixed O&M costs

- Incremental annual operating margin (revenues from energy and ancillary service sales less variable fuel and O&M costs) provided by dual-fuel capability

The potential annual operating margin (revenues from energy and ancillary service sales less variable fuel and O&M costs) will be enhanced by dual-fuel capability due to option value. Typically, a dual-fueled plant would bid into the energy market on any given day at the lower total variable cost of natural gas or ULSD, based on prevailing market conditions. The PPAs typically dispatch the resource based on cost minimization, *i.e.*, the stacking of resources reflecting least cost. ULSD capability would allow the plant to operate when natural gas fuel is unavailable or is priced higher than ULSD and the market energy and/or ancillary service price is high enough to warrant ULSD operation. The magnitude of the potential added operating margin is driven both by market conditions (natural gas prices, ULSD prices, load, availability and characteristics of other generators) and by the specific performance parameters of the plant in question, such as capacity, heat rate, non-fuel variable costs, minimum load, ramp rate and ability to switch fuels quickly. Appendix 41 shows the key performance parameters for each of the selected gas turbine configurations at ISO, winter, and summer conditions. These parameters are discussed in greater detail, including adjustments for elevation above sea level, for selected locations in Section 11.6.6.2.

Figure 11-1 shows the non-fuel variable costs for the selected configurations on both natural gas and ULSD, assuming winter conditions. CO_2 allowances are shown as shaded bars which may or may not be relevant, depending on the development of carbon markets. The cost of future NO_x allowances is also uncertain, due to uncertainties arising from implementation of the Cross State Air Pollution Rule and potentially more stringent NAAQS for ozone. Figure 11-2 adds the estimated cost of fuel to obtain total variable cost. This chart shows that the differences in variable O&M cost, depending on choice of fuel, are small compared to the costs of the fuel itself. Natural gas costs are shown at a typical winter price level and at a level corresponding to the high prices observed during the Polar Vortex in the Northeast. Note that a plant receiving FT service would procure the gas commodity at a more stable pricing point and would not directly pay the spiked downstream commodity price. Some generators might still view the spiked price as an opportunity cost if they could more profitably lay off their firm capacity.

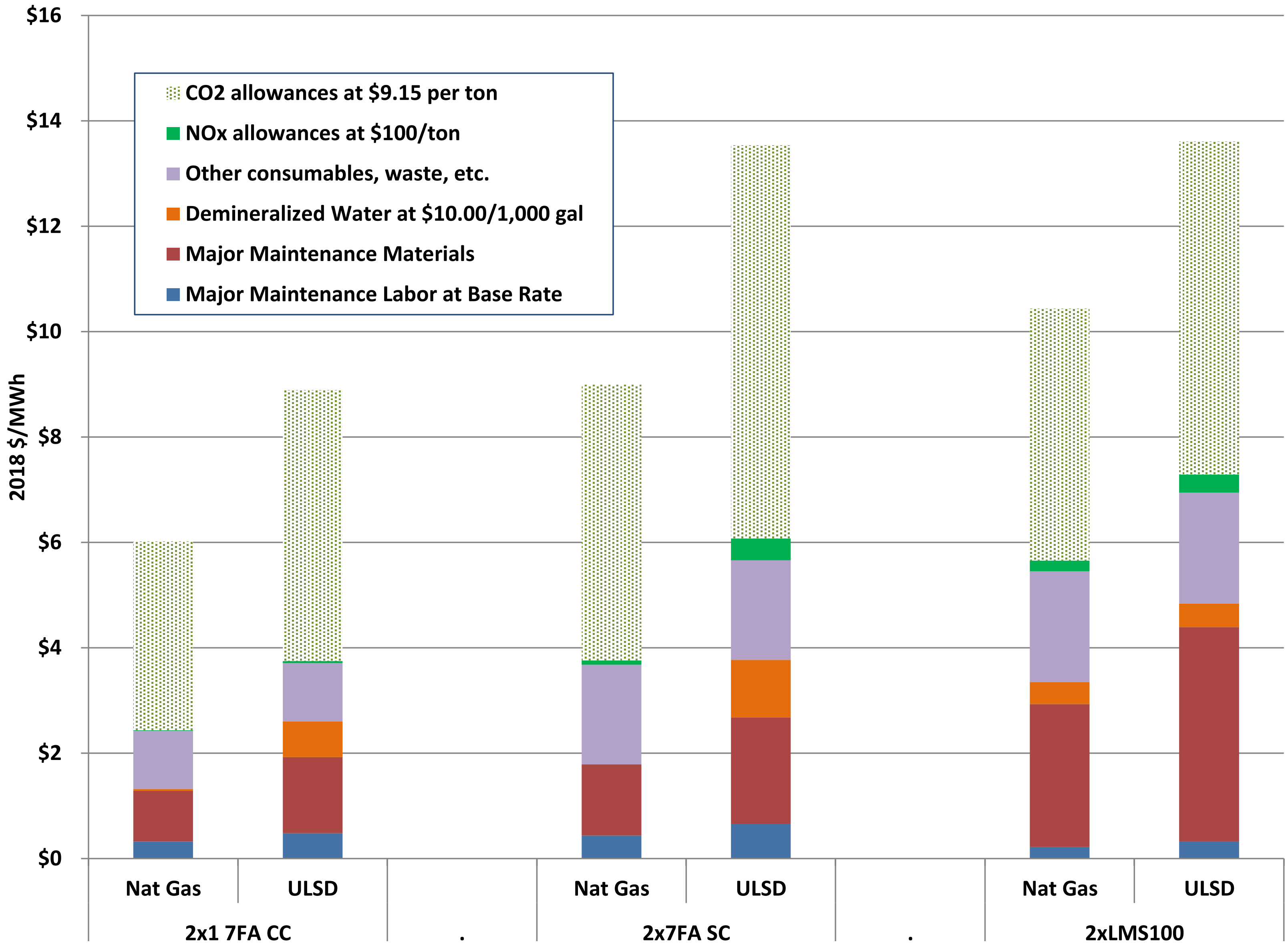

Figure 11-1. Variable O&M Comparison

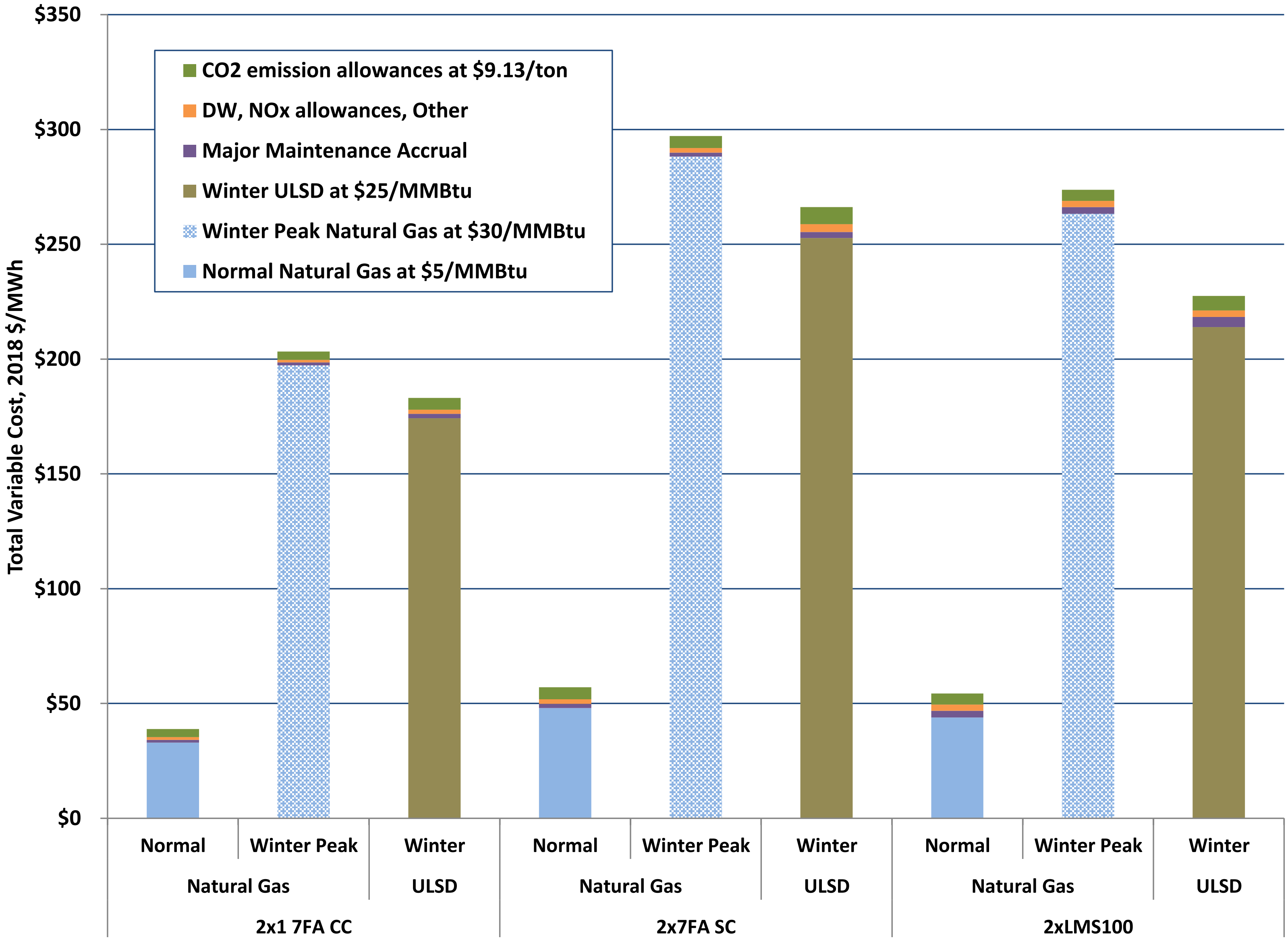

Figure 11-2. Total Variable Cost Comparison

11.4 Market Availability, Resupply Options and Specifications for ULSD

11.4.1 Distillate Fuel Oil Market

The distillate fuel oil market has experienced dramatic changes over the last few years that are improving the availability of alternate fuel at SC and CC plants. While the overall production of distillate fuel has grown by about 2.5 % annually over the past 10 years, the ULSD share of distillate production has surged, increasing from less than 1% of total distillate fuel oil production in 2003 to more than 92% in 1H-2014.[40] As the production of ULSD has increased, the production of #2 FO has materially declined. Production of #2 FO now represents only 6% of the U.S. market. In May 2013, reflecting the changing character of the distillate fuel oil market, the NYMEX converted the standard heating oil futures contract to a ULSD contract. Increasingly stringent emission regulations governing distillate fuel use in transportation, commercial, and residential applications have been driving these changes. Following this trend, the air permits that allow dual-fuel capabilities for most new SC and CC plants require the use of ULSD as the back-up fuel. In response, the U.S. refining industry has been making process upgrade investments that have shifted the slate of products to emphasize ULSD. The EIA forecasts that growth in ULSD consumption, coupled with declining gasoline consumption, will provide further support to shift refinery production toward ULSD.[41]

Rapidly growing shale oil production has increased the supply of light sweet crude available to U.S. refiners at a significant price discount to international crude (Brent) prices. As a result, U.S. refiners have been making process changes and investments to accept more light sweet crude as well as to increase ULSD output. Favorable refining economics, resulting from lower crude costs, lower hydrogen costs due to lower natural gas costs, and attractive margins available from ULSD, have provided sufficient financial incentives for refiners to invest in new and revamped hydrocracking and hydrotreating facilities,[42] improved fractionation, and move to catalysts that favor increasing ULSD yields.[43] While less efficient refining capacity that cannot easily increase ULSD production has shut down, total U.S. refining capacity has increased over the past seven years from 17.1 to 18.1 million barrels per day with hydrocracking capacity increasing over the same period by more than 19 %.[44] Favorable costs and product pricing have allowed U.S. refiners to run at high utilization rates and are transforming the U.S. into a major exporter of petroleum products. Net ULSD exports increased to 874,000 BPD in 2013 from essentially zero net exports in 2008.[45] Exports provide stability for the domestic market in that exports can be

[40] EIA U.S. refinery and blender net production of distillate fuel oil.

[41] EIA Annual Energy Outlook 2014.

[42] Hydrocracking is a catalytic process that breaks down larger, heavier molecules to produce lighter products such as ULSD, while hydrotreating removes sulfur and other impurities with the addition of hydrogen to produce low sulfur products such as ULSD.

[43] EIA, Office of Petroleum, Gas and Biofuels Analysis, "Increasing Distillate Production at U.S. Refineries – Past Changes and Future Potential," October 2010.

[44] Hydrocarbon Processing, "Overcome the imbalance between diesel and gasoline production," September 1, 2014.

[45] EIA U.S. supply and disposition of crude oil and refined products.

diverted to the domestic market as an additional supply, subject to contract requirements, if product supply balances tighten.[46]

11.4.2 ULSD Market Implications

The changes in the distillate fuel oil market represent very positive developments in regard to ULSD availability as an alternate fuel for dual-fuel capable generators across the Study Region. The market transition to ULSD – coupled with the NYMEX conversion of the futures contract – has reduced operating pressures on the distillate oil supply chain to keep pace with the needs of dual-fuel capable generation. Simply put, when #2FO was the primary back-up fuel for oil-fired SCs and CCs, generators represented a much larger portion of a comparatively smaller market. Increasing reliance on ULSD means that dual-fuel generation represents a smaller part of a much greater market, thereby suppressing the seasonal demand peak problems traditionally experienced in the #2 FO heating oil market. Going forward dual-fuel capable generators will face less competition with RCI customers for ULSD supplies during the peak winter heating demand periods since electric generators and RCI end-users will be buying fuel in the much larger and less seasonal ULSD market. Likewise, the ULSD distribution system includes much greater transportation and delivery capabilities.

The ULSD market exhibits relatively minor seasonality, with demand peaks usually occurring during the non-winter months. The primary use of ULSD in the on-highway and off-highway markets tends to be affected by much less seasonality with more stable year-round demands. The conversion of most of the Northeast states that form the major part of the space heating oil market to require ULSD use after 2018 (New York has already converted) will add to the seasonal demand for ULSD. While this increases the demand for ULSD, the shift to ULSD for residential and commercial use moves the heating oil demands into a much larger market dominated by transportation demands that are largely insensitive to winter demand peaks. Figure 11-3 shows the U.S. distillate fuel oil consumption in 2012 (the latest year for which EIA has end-use data) by end-use.

[46] EIA, "Outlook for Refinery Outages and Available Refinery Capacity in the First Half of 2014," February 2014.

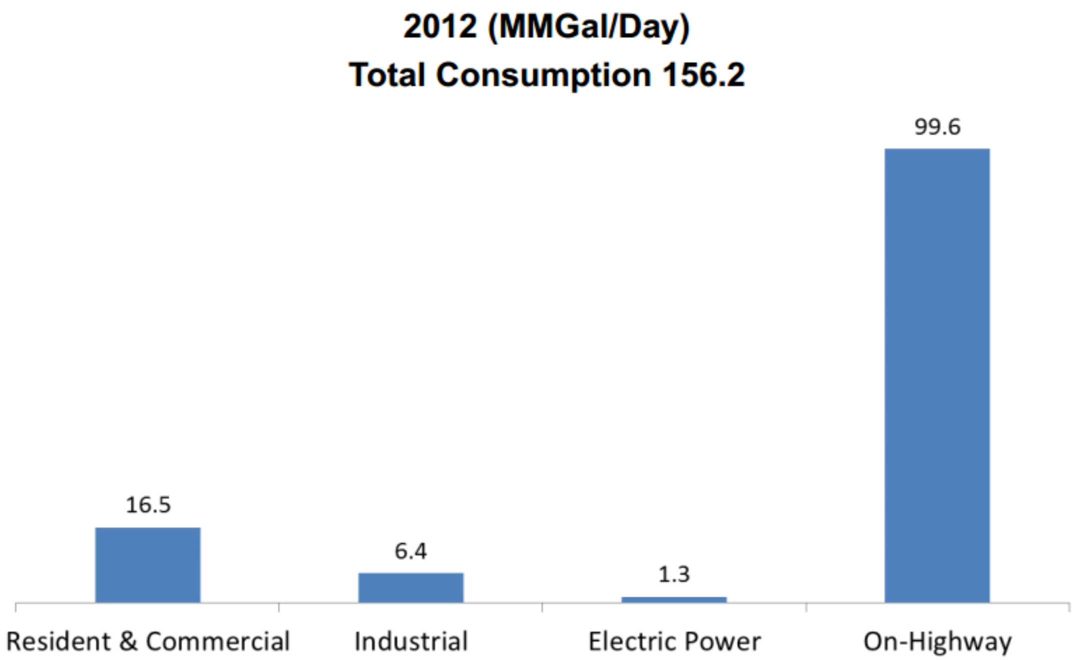

Figure 11-3. U.S. Distillate Fuel Oil Consumption By End-Use

In the ULSD-dominated distillate fuel market, electric demand for distillates amounts to less than 1% of total distillate fuel oil demand while residential and commercial demands account for about 10%. On-highway transportation use accounts for almost 64% of the total. Other uses not shown include distillate fuel oil consumed for agricultural uses and off-highway transportation. Given the large and growing share that ULSD holds in the distillate fuel oil market, the declining supply of higher sulfur #2 FO has turned #2 FO into a niche market with poor liquidity, limited availability, and fewer truck tank trailers or barges available to move this now specialized product. The lower sulfur content of ULSD means that any transport mode that moves higher sulfur distillate fuels such as #2 FO must be flushed and cleaned prior to transporting ULSD to avoid contamination. While many of the dual-fuel generators identified in Section 11.2 currently store and utilize #2 FO and other higher sulfur distillate fuels, the revolutionary changes in the distillate fuel oil market mean that ULSD has become the primary alternate fuel for dual-fuel capable SC and CC generators.

The current ULSD market and refining capacities are adequate to meet generators' demands for back-up fuel. Based on the technical review LAI conducted for Target 4 analysis, the ULSD supply chain, including transportation, distribution, and storage (both off-site and on-site) is sufficiently robust to meet generator back-up fuel needs as well due to the widespread distribution and use of ULSD. LAI's review of the location of major wholesale terminals and refinery storage facilities indicates that the Study Region is well served by a combination of river terminals, coastal storage facilities, and refineries in the Study Region and along the Gulf Coast that can move ULSD to markets into the Northeast by water. There are also storage facilities located along several major petroleum product pipelines serving the Northeast, Midwest, and Southeast. The key to assuring sufficient supplies of ULSD to meet generator needs during peak winter periods will involve a combination of transportation scheduling and maintaining adequate on-site supplies going into the winter season.

During extended periods of extreme cold weather, the ULSD supply chain is capable of providing timely back-up fuel replenishment in most parts of the Study Region. Keeping up with ULSD burns during extreme weather events will depend on the plant's ULSD on-site storage capacity and unloading facilities as well as the size of the plant. The primary constraint for resupplying large plants is likely to be local restrictions on truck traffic, not the availability of ULSD. Since the management of new plants will be aware of such restrictions, the on-site storage capacity for ULSD could be increased accordingly at the time of the plant's construction. The incremental cost of expanded ULSD storage capacity is relatively low.

In Section 11.2 LAI addressed the issues and capacities associated with on-site storage and provided data regarding on-site volumes and estimated hours of full load operation for a representative group of dual-fuel generators in the Study Region. The average on-site distillate fuel storage capacity amounts to approximately 96 hours of full load operation, excluding the TVA plants. [47] The winter season average on-site inventory for the TVA plants is 72 hours of full load operation.

The data in Section 11.2 show a wide range of on-site storage capabilities among these plants, with the average integrated utility plant having 80 hours (full load operation) of on-site storage capacity while the average merchant plant having 110 hours of on-site storage capacity. The larger value for the merchant versus utility plants may be an artifact reflecting the plants for which such data were publicly available. For example, a number of merchant plants, such as Doswell, with in-service dates in the early 1990s, were constructed with relatively large on-site storage capacities relative to more recent plant additions.[48] Other merchant plants were built on or adjacent to existing steam units and thus may benefit from existing large on-site storage capacities designed to receive barge deliveries. Moreover, locations adjacent to existing steam units often have more room for new on-site storage tanks with less local zoning restrictions, thereby facilitating conversion of large existing oil storage tanks to ULSD. These data also show that CC plants have on-site storage capacities averaging 107 hours of full load operation and the SC plants in the data base average 79 hours at full load.

11.4.3 ULSD Specifications and Utilization Issues

The use of ULSD in SCs and CCs poses some additional challenges relative to higher sulfur distillate fuels. Table 11-16 provides a summary of the key ULSD specifications for use as a back-up fuel based on ASTM D 975 qualifications.[49]

[47] The hours at full load operation for the TVA SCs and CC are based on TVA's target inventory numbers.

[48] Doswell entered into a long term PPA with Virginia Power Co., the cost of which is an automatic pass through to Virginia Power's retail customers under VA SCC jurisdiction.

[49] American Electric Power Service 2014 Fuel Oil Request for Quote Guidelines, Exhibit A Diesel Fuel Specifications.

Table 11-16. Ultra Low Sulfur Diesel Specifications

Specification	Required Properties
Viscosity	Not less than 1.9 mm2/s or more than 4.1mm2/s at 40 degrees C
Flash Point	Not less than 54 degrees C
Pour Point	September through March -18 degrees C maximum April through August -12 degrees C maximum
Carbon Residue	0.35 % or less
Sulfur Content	15 ppm or less
Cetane Number	Not less than 40
Lubricity	Not greater than 520 microns
Conductivity	Not less than 25 pS/m
Ash Content	Not more than 100 ppm

ULSD that is used in off-highway applications, including for electricity generation, is dyed red to differentiate it from #2 FO for tax purposes. ULSD is more susceptible to biological fouling than higher sulfur distillate fuels and is generally treated with a biocide that is added in the storage tanks. ULSD lubricity can exceed the maximum specification at times, typically running at or slightly above 600 microns, which is usually addressed by additives mixed with the ULSD at the supplier's terminal or at the refinery prior to shipment. The ULSD pour point can be lowered for winter use in cold climates, again through the use of additives, although many turbines are equipped with fuel oil heaters or recirculation systems.[50]

[50] Hoy, M., Tennessee Valley Authority, "Distillate Handling, Firing, Learn from Long-term Experience in Burning Fuel Oil," CCJ Online, Combined Cycle Journal, 2012.

11.5 Fuel Switching Design and Practice

11.5.1 Operational Considerations for Fuel Switching

CT manufacturers have offered dual-fuel capability for a long time. Over the past few years, progress has been made by manufacturers to improve the operator's ability to quickly switch fuels. Manufacturers often claim that switching can be accomplished at or near full load, but they recognize the practical advantages of reducing CT loading when switching fuels to minimize the chances of a unit trip or a NO_x emission excursion.[51] Similarly, operators often bid to operate at a steady load when firing liquid fuel to avoid load changes and minimize the possibility of NO_x emission excursions. Operators' reluctance to risk a NO_x emission violation is reasonable: however, these risks can be minimized by having trained operators carefully follow procedures during fuel switching and load ramping.

In New York City, Con Edison requires that dual-fuel units be capable of switching from natural gas to ULSD in 45 seconds. GE claims that the 7F.05 CT can switch from full load operating on natural gas to operating on liquid fuel within 45 seconds without interruption.[52] When operating at full load, GE recommends that the unit first ramp down from full load to about 80% load prior to conducting the fuel transfer in order to minimize the risk of a trip or emission excursion. The GE LMS100 can also achieve a full load fuel switch in less than 60 seconds without ramping back load, provided that liquid fuel is being circulated at the required pressure and temperature. Presetting the fuel circulation and temperature must be initiated by operator command, which would normally be done ahead of time on any day that a switchover might be anticipated.

CT manufacturers generally recommend that plant owners regularly conduct tests of liquid fuel systems (and associated systems such as water injection) to assure their readiness and to routinely train plant operators. Plants that have Long Term Service Agreements with those manufacturers may be required to perform such testing to maintain liquid fuel operating and emission guarantees. These tests do not necessarily require a full switch from natural gas to ULSD and back, but are often limited to establishing ULSD combustion and injection water flow at a low percentage of total fuel input periodically. More extensive tests would confirm the ability to perform a full switch in a few minutes without emissions excursions. In either case, any fuel switching tests require firing ULSD at times when it is usually much more expensive than firing natural gas.

11.5.2 Cost Recovery for Liquid Fuel Testing

While RTO tariffs may allow plants to self-schedule plant operation for liquid fuel testing, only TVA covers the reimbursement of those incremental testing costs above the prevailing LMP. Testing on ULSD when natural gas prices are lower than liquid fuel prices and are setting the

[51] In general, short-term excursions would not violate air permit limits since air emissions are averaged over some period of time.
[52] See affidavit of Chris Ungate, Sergeant & Lundy, submitted to FERC by NYISO, Docket No. ER14-500, January 9, 2014, p. 6.

LMPs thus imposes a substantial operating cost in addition to the incremental fixed O&M costs that affect a merchant generator's bottom line. While merchant plant operators may thus be reluctant to test fuel switching capability any more than absolutely necessary, some RTOs (notably ISO-NE and PJM) are considering proposals to offer other types of compensation or performance incentives to ensure that dual-fuel plants can operate when called upon during the winter heating season.

In order to confirm whether (i) PPAs require dual-fuel capability testing, (ii) plant operators are able to recover the costs of such tests and (iii) other compensation or performance incentives are offered, LAI distributed a question set via email to the PPAs and received the following information. LAI supplemented this with information on the PPA websites.

11.5.2.1 NYISO

NYISO confirmed that its Tariff does not require generators to test their backup fuel systems; hence, there is no cost recovery mechanism for doing so. During full load DMNC testing, generators are exempt from performance penalties. NYISO also confirmed that Con Edison (i) requires generators in New York City to demonstrate their back-up oil inventory (either on-site or off-site) and (ii) requires new plants in New York City to have auto-fuel-swapping and be tested semi-annually.

11.5.2.2 IESO

IESO has informed LAI that there are no requirements for dual-fuel testing and thus no mechanism to recover the costs of that testing; however ,there is only one dual-fuel plant in its system.

11.5.2.3 MISO

MISO confirmed that dual-fuel units can self-schedule to test their backup fuel systems but there is no cost recovery mechanism for generators to be paid more than the LMP. Dual-fuel units are not required to demonstrate backup fuel capability or on-the-fly switching. We are not aware of any current efforts to improve system reliability by expanding or enhancing local dual-fuel capability.

11.5.2.4 PJM

Through its stakeholder process at the Operating Committee, PJM is pursuing a number of market reforms to enhance system reliability during cold weather events such as those which occurred in January 2014. The process began in April 2014 has a target completion date of October 31st. PJM staff released two whitepapers: a Problem Statement on August 12th and a Capacity Performance Proposal on August 20th, which was subsequently revised on October 7.

The Proposal will add an enhanced capacity product – Capacity Performance – to its capacity market structure and will reinforce the existing definition of the Annual Capacity product.[53]

11.5.2.5 ISO-NE

ISO-NE has instituted short-term remedial measures and is proposing additional long-term measures to enhance the ability of dual-fuel plants to operate when gas supplies are constrained. The most recent measures for the 2014-15 winter were included in a July 11, 2014 FERC filing (docket ER14-2407) to modify ISO-NE's Operating Agreement and Tariff as follows:

- The Unused Oil Inventory Program is designed to insure that dual-fueled plants have a sufficient minimum level of oil inventory entering the winter heating season. To participate, a plant's minimum inventory level as of December 1st must be 85% of the usable tank capacity, up to 10 days of full load operation. At the end of the winter, program participants will be compensated for the lesser of their December 1st and March 15th inventory levels, subject to the 85% / 10 day cap. Inventory compensation is set at $18/barrel, subject to performance adjustments, and ISO-NE anticipates that the aggregate minimum back-up oil inventory will be 3.8 million barrels.

- The Unused Contracted LNG Program is designed to offset the cost of unused LNG contract volumes. ISO-NE will compensate up to 6 Bcf in aggregate, equivalent to approximately 1 million barrels of oil, at $3/MMBtu. Generators must have take-or-pay LNG contracts, must apply by December 1st, and will be compensated at the end of the winter based on the lesser of December 1st and March 1st contract volumes, not to exceed the amount of fuel necessary to permit the generator to operate for four days at full load.[54]

- The Dual-Fuel Commissioning Cost program will compensate dual-fueled generators for commissioning costs (or re-commissioning costs for generators that have not operated on oil since December 1, 2011). Generators must (i) notify ISO-NE by December 1, 2014 and have a target commissioning date before December 1, 2016 (with incentives for commissioning by December 1, 2015), (ii) have an oil tank that holds enough fuel to start the generator from a cold state and operate at its Economic Minimum Limit for the greater of four hours or the generator's minimum run time, (iii) have the ability to switch

[53] PJM distributed an Updated Proposal on October 7th that is generally consistent with the August 20th version.

[54] Generators in New England can be served by two onshore LNG import terminals, the GDF Suez facility at Everett and the Repsol Canaport terminal in New Brunswick. Excelerate has an offshore buoy submersible LNG facility as well. These import facilities could provide LNG for a peaking service to mitigate upstream pipeline constraints or to displace ULSD to provide fuel assurance during the peak heating season. A seasonal LNG service could provide generators with a call option for peaking gas supplies or short-notice peaking supply. The pricing, delivery logistics and replenishment constraints associated with a LNG seasonal peaking service have not been evaluated in the Target 4 analysis.

fuels within eight hours, and (iv) the ability to run on oil at the Economic Maximum Limit for at least one hour.

- The DR program is designed to help ISO-NE maintain thirty minute reserves by reducing load or operating behind-the-meter generation. This program is open to DR assets that may or may not be participating in the wholesale markets. This program is limited to 100 assets and 100 MW. Dispatch is limited to 180 hours per winter period, with a monthly payment rate of $1.80/kW-month and an energy payment equal to the LMP plus a 1.065 energy loss factor, subject to a $250/MWh cap.

- ISO-NE is eliminating the requirement that dual-fueled plants burn the higher-priced fuel when its offers are based upon that fuel. This is intended to give generators more flexibility in case the generator can obtain lower-priced fuel supplies. Other reporting requirements will also be relaxed.

- Last year, ISO-NE adopted rules to compensate dual-fuel generators if they were able to test their fuel switching capability successfully. These audits of 13 units cost $1.7 million and provided ISO-NE operators with increased certainty on the operational readiness and the confirmed functionality of fuel-switching capability of those generators. ISO-NE will continue this audit program and will compensate generators for their dual-fuel testing costs.

11.5.2.6 TVA

TVA confirmed that plant scheduling is centrally coordinated and on-the-fly fuel switching fuel is tested monthly and prior to the summer and winter seasons, with a target to be at full load within 10 minutes. TVA's plants are allowed to recover these testing costs while similar provisions are unavailable for merchant plants. If a dual-fuel plant is operating at full load, TVA confirmed that it lowers load before switching fuels and then ramps back up to full load. TVA believes that regular testing makes liquid fuel operation more reliable and allows it to achieve a 90-95% fuel-switching success rate. TVA indicated that regular testing is particularly important in winter conditions when check valves can become sticky and fuel nozzles can become coated, which can cause combustion upsets and turbine trips.

11.5.3 Fuel Switching Operations

Dual-fuel CTs are usually provided with a recirculating fuel oil system that can continuously circulate fuel from storage to the CT and back. Fuel is extracted for use as needed. The circulating fuel cools the portions of the fuel system exposed to high temperatures close to the CT unit to help avoid coking. In this mode, liquid fuel is instantly available to start a switchover when initiated by operator action or automatically triggered by a low gas pressure signal. During periods when the need for a quick switch-over is unlikely, the recirculation may be turned off, and the portion of the system subject to high temperatures can be purged with nitrogen or air[55] to

[55] GE uses a nitrogen purge system for the 7F.05 CT, but includes an air purge with the dual-fuel package for the LMS100.

avoid leaving liquid fuel exposed to coking. Restarting the entire recirculation system can take several minutes, according to GE.

11.5.3.1 Inventory Cycling

With liquid fuel storage capacities generally in the 2-5 day range, dual-fuel capable SC and CC stations will likely cycle through their liquid fuel inventory in a year or less. Since ULSD is a valuable commodity all year in the transportation market, operators might be inclined to run down inventory in the spring, then restock in the fall, thus avoiding year-around carrying charge and risks of fuel deterioration due to bacterial activity during the summer, when it is unlikely to be used.[56]

11.5.3.2 Distillate Fuel Oil Implications for SCR

The combustion of distillate fuel oil results in higher NO_x emissions than the combustion of natural gas. In addition, the performance of SCR catalysts for NO_x reduction can deteriorate when the CT is fired on distillate fuel oil primarily as the result of masking. Masking occurs when the surface of the SCR catalyst is fouled with combustion products. These primarily carbon-based combustion products are more likely to occur when burning distillate fuel oil. The impacts of SCR catalyst masking resulting from relatively short operation on distillate fuel (as would most often be the case for back-up fuel use) can generally be reversed when natural gas burning is resumed, which, in effect, burns off the carbon deposits.

[56] Before ULSD is delivered to a non-transportation user such as power plants, it is dyed to prevent its diversion to transportation use without taxation. This reduces the financial liquidity of the fuel and makes reselling unused fuel in the spring a difficult option.

11.6 Tradeoffs between Dual-Fuel Capability and FT Service

11.6.1 Overview

LAI has expanded the cost model described in Section 11.3 to calculate the levelized annual cost for liquid fuel back-up and FT service. Location-specific variables have been used to facilitate the comparison of both approaches to fuel assurance. Across the Study Region, system reliability can be improved through fuel arrangements that allow gas-fired generators to operate reliably year-round. To satisfy the PPAs' fuel assurance objectives, LAI has estimated the incremental capital and fixed operating costs of two options that are *roughly* equivalent in terms of plant reliability: (i) providing fully-functional, all-season, dual-fuel capability for a new gas-fired plant under an assumed set of gas transportation constraints and oil replenishment logistics; and, (ii) entering into an FT arrangement with an interstate gas pipeline.[57]

Development of a cost model for estimating the incremental capital and fixed operating costs for dual-fuel capability was presented in Section 11.3. Incremental capital costs include additional oil and water storage tanks, forwarding and injection equipment, different burner nozzles, modifications to the CT and other equipment, the net cost of startup testing on liquid fuel, and incremental NO_x emission offsets. Incremental fixed operating costs include maintenance costs, insurance and property taxes on incremental plant and equipment, net costs of regular test-firing on liquid fuel, and the carrying charge for inventory of liquid fuel. In lieu of dual-fuel capability, to estimate the additional cost of FT service relative to non-firm service,[58] LAI relied on pipeline filings and other public information for new pipeline projects. An incremental FT rate pertaining to deliverability to the constrained location identified in the Target 2 report has been identified. A unit rate for FT has been incorporated in this analysis. More details on the derivation of these rates are presented in this section.

To assess the relative economics associated with dual-fuel capability versus firm transportation by location, the PPAs provided a list of locations for new SC and CC plants. For each location, LAI has estimated the incremental cost of dual-fuel capability and firm transportation to allow for a standard economic comparison of relative cost. In this section, LAI describes the process by which the sites were modeled to support the results presented in Section 11.6.8.

[57] The cost to convert an *existing* gas-fired plant to dual-fuel and quantification of the margin from energy sales associated with a firm transportation entitlement are not part of the Target 4 study. A generator's willingness to invest in dual-fuel capability may be affected by an array of economic and market factors, including PPA tariff provisions that may impose penalties on capacity resources for non-performance.

[58] Throughout this report, non-firm transportation service may include interruptible transportation purchased directly from a pipeline, secondary capacity arrangements with an assignor that releases capacity subject-to-recall, or a third party arrangement with a marketer under an Asset Management Agreement (AMA). Because IT rates are transparent, but third party arrangements under AMAs are not, Target 4 analytic results reflect the use of IT rates.

11.6.2 Location Selection and Definition

The PPAs identified locations for further analysis based on the results of the Target 2 research, locations that are of particular concern with respect to electric-side reliability, and locations that may be well-suited for the repowering of existing technology. The 27 locations identified by the PPAs are listed in Table 11-17. In those instances where the geographic locations were not specified by the PPA, LAI exercised judgment regarding the municipality and county to define the location. As discussed in Section 11.3, three plant configurations were considered: (i) 2x1 7FA combined cycle plant, (ii) 2x7FA simple cycle plant, and (iii) 2xLMS100 simple cycle plant. Based on the NO_x emission compliance level for each location, one of the two simple cycle plant configurations was chosen for final analysis.

Table 11-17. PPA Location Selections

No.	PPA	Location Name	PPA Zone	State/ Prov.	City/Town	County
1	ISO-NE	Central CT	CT	CT	Middletown	Middlesex
2	ISO-NE	SW CT	CT	CT	Norwalk	Fairfield
3	ISO-NE	Cape Cod	SEMA	MA	Sandwich	Barnstable
4	ISO-NE	SE MA	SEMA	MA	Somerset	Bristol
5	ISO-NE	Maine	ME	ME	Yarmouth	Cumberland
6	ISO-NE	New Hampshire	NH	NH	Bow	Merrimack
7	ISO-NE	Vermont	VT	VT	Vernon	Windham
8	NYISO	New York City	J	NY	NYC (Astoria)	Queens
9	NYISO	Long Island	K	NY	Yaphank	Suffolk
10	NYISO	Lower Hudson Valley	GHI	NY	Newburgh	Orange
11	NYISO	Capital District	F	NY	Albany	Albany
12	MISO	Upper Peninsula	North	MI	Marquette	Marquette
13	MISO	Twin Cities	North	MN	St. Paul	Ramsey
14	MISO	Southern Illinois	Central	IL	Carbondale	Jackson
15	PJM	Dominion North	Dominion	VA	Arlington	Arlington
16	PJM	PEPCO	PEPCO	MD	Washington	DC
17	PJM	BGE	BGE	MD	Baltimore	Baltimore
18	PJM	Delmarva	Delmarva	DE	Wilmington	New Castle
19	PJM	PECO	PECO	PA	Philadelphia	Philadelphia
20	PJM	PSEG North	PSEG N	NJ	Newark	Essex
21	PJM	PSEG South	PSEG S	NJ	Trenton	Mercer
22	TVA	Maury East	Central	TN	n/a	Maury
23	TVA	Colbert	South	AL	n/a	Colbert
24	TVA	Johnsonville	Central	TN	Johnsonville	Humphreys
25	TVA	Summer Shade	Central	KY	Summer Shade	Metcalfe
26	IESO	Central	Central	ON	Toronto	n/a
27	IESO	East	East	ON	Gr. Napanee	n/a

11.6.3 Natural Gas Supply and Delivery by Location

LAI developed relevant characteristics for natural gas transportation and delivery. For each of the 27 location, an assumption was made regarding the cost of incremental FT service or non-firm service.[59] A supply path from the gas producing basin to the constrained location was identified. For 7 of 27 locations, the supply path from the producing basin to the plant gate includes local distribution company transportation. All other locations are assumed to be directly connected to an interstate pipeline. Some paths include upstream pipeline segments, thus requiring the incurrence of "pancaked" transportation rates. FT paths are generally the same as for IT, except in those instances where LAI incorporated a cost from the LDC's distribution franchise to the nearest pipeline gate station. This cost represents a proxy for the uncertain cost of local facility improvements.[60]

11.6.3.1 FT Paths and Reservation Rates

In order to estimate the cost of FT by location, LAI relied primarily on publicly available data sources. Such sources reported the cost of incremental capacity on pipelines of relevance for incremental firm service. The currently effective FT rate on each pipeline was reviewed. However, most pipelines, particularly those serving entitlement holders throughout the Study Region, are fully subscribed and, in some instances, fully or near fully utilized during the peak heating season. Hence, in many cases it would not be possible for a new CC or SC plant to obtain FT service at the existing tariff rate. To obtain FT service, the shipper must be willing to enter into a contract with the pipeline that obligates the benefitted shipper to pay for facility improvements that support incremental firm service. Under FERC cost of service, such costs are typically borne by new shippers rather than rolled-in to existing rates, thus ensuring no cross-subsidization from existing to new shippers when the benefits of such system improvements are limited to the new shipper rather than distributed across the system. In order to estimate the incremental cost of FT in these situations, LAI reviewed recent pipeline certificate applications before FERC.

One constrained location evaluated in this analysis is in Newark, New Jersey. LAI assumed that a new generator located in Newark would be directly connected to Transco. Transco's pipeline in this area is presently fully subscribed, thus requiring additional facilities. Transco's Leidy Southeast project consists of loopline and compression designed to increase the pipeline's delivery capability from Marcellus.[61] In its certificate application, Transco indicated that the

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[59] For simplicity sake, the cost of non-firm service is assumed to be the embedded cost of IT on one or more pipeline(s) from the producing basin to the location. In actuality, the cost of non-firm service varies by season and may be higher or lower than the IT rates used in this analysis.

[60] Coordination with LDCs to define the incremental cost of local facility improvements to render firm service was not part of the Target 4 analysis.

[61] See Transco's Leidy Southeast Project certificate application at FERC, Docket No. CP13-551. The Leidy Southeast Project will enable Transco to provide 525 MDth/d of incremental firm transportation service from Leidy Line receipt points to mainline delivery points.[61] Seven shippers have contracted for the full capacity of the project: Anadarko Energy Services

reservation rate for new firm service would be $20.50/Dth-month, which was used as the cost of FT for that location.

In some instances, a location was analyzed where a pipeline has recently announced plans to increase capacity, but not yet filed an application at FERC. For example, facility additions in Arlington, VA and Washington, DC could be served by Transco's Atlantic Sunrise project, which consists of new looping and compression designed to accommodate increased production from Marcellus.[62] Transco is expected to file a certificate application at FERC in 2015. Transco has not, to date, conducted an open season for the new capacity. In conducting the open season, Transco indicated that the maximum recourse rate for the project will range between $21.29/Dth-month and $26.16/Dth-month.[63] In this case, LAI assumed the average, or $23.73/Dth-month.

In some instances, pipeline capacity is not fully subscribed. Therefore incremental FT may be available at the existing embedded cost rate. In some locations across the Study Region, additional FT is likely available without pricing the cost of new facilities. An example is the TVA Johnsonville location that can be served by the Tennessee pipeline. The plant is located in Tennessee's Zone 1. A review of current contract entitlements indicated that there is existing capacity on Tennessee to move natural gas from Zone 0 to the plant at Zone 1.[64] In cases such as these, we have assumed that the new facility would purchase capacity directly from the relevant

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Company, Capitol Energy Ventures Corp., MMGS Inc., Piedmont Natural Gas Company, Inc., Public Service Company of North Carolina Inc., South Carolina Electric & Gas Company and Washington Gas Light Company. The total estimated project cost is $607.3 million. The target in-service date is December 1, 2015.

[62] See Transco's Atlantic Sunrise Project request to initiate a pre-filing review at FERC, Docket No. PF14-8. The project's facility improvements will create 1,700 MDth/d of incremental firm transportation capacity along two paths from Pennsylvania to Alabama and Virginia. The first path, which has eight contracted shippers, will create 850MDth/d of capacity from receipt points on the Leidy Line to Compressor Station 85 in Alabama. The second path, which has one contracted shipper, will create 850,000 MDth/d from a new receipt point north of the Leidy Line in Susquehanna County, PA to Transco's Cascade Creek interconnection with Dominion Cove Point. Project facilities include 179 miles of pipe along new rights-of-way in Pennsylvania, 17 miles of loopline and replacement pipe in Pennsylvania, two new compressor stations in Pennsylvania, incremental compression at two stations in Pennsylvania and one station in Maryland, and other related facilities. The target in-service date for all facilities is July 1, 2017. The contracted shippers were not identified in the pre-filing request, and a certificate application is expected in May 2015.

[63] http://www.1line.williams.com/1Line/wgp/download?delvid=5611994&hfNoticeFlag=Y&hfDownloadFlag=
false&hfFileName=download.html

[64] Additionally, TVA already has a plant located at Johnsonville and has firm entitlements to the facility. In this case, we have therefore assumed that if a new facility were developed in place of the existing plant, TVA could utilizing its existing entitlements on Tennessee to serve that new facility.

pipeline(s) at the current tariff rates. For Johnsonville, the applicable rate on Tennessee is $11.94/Dth-month. Other locations that could be served by pipelines that would likely be able to furnish such service under the existing embedded cost rate are Upper Peninsula, Michigan; Twin Cities, Minnesota, Southern Illinois; Johnsonville, Tennessee; IESO Central, Ontario, and IESO East, Ontario.

For each constrained location, the incremental cost of FT captures the supply chain from the producing basin to the generator location. For locations in the greater Northeast – ISO-NE, NYISO, and the MAAC portion of PJM – the supply chain almost always extends to Marcellus/Utica. However, in New England, one location extends "back" to Atlantic Canada. In MISO North/Central and TVA, the supply chain is from Texas and/or the Gulf of Mexico. In Ontario, the supply chain is from Western Canada via the TransCanada mainline.

For a number of locations, geographic factors would require a facility to obtain FT on more than one pipeline in order to assure deliverability from a producing basin. For example, constrained locations in New England such as the Cape Cod, SE MA, and Central CT locations, could be served by Spectra Energy's AIM project. Pursuant to Spectra's filing in CP14-96, the recourse rate for shippers utilizing the capacity generated by AIM will be $42.575/Dth-month when the project goes in service in November 2016. However, AIM provides new capacity from Algonquin's interconnection with Texas Eastern at Mahwah, New Jersey. For these constrained locations, an upstream entitlement from Marcellus to Mahwah would be required in order to assure delivery. LAI has assumed that capacity made available by the Texas Eastern TEAM 2014 project.[65] The upstream FT rate for TEAM 2014 capacity from Marcellus to Mahwah is $13.98/Dth-month. Therefore, the total mainline cost of FT for the Cape Cod, SE MA, and Central CT locations is $56.55/Dth-month, *i.e.*, the cost on AIM plus FT on TEAM 2014. Although AIM includes incremental deliverability on Algonquin's "G" system in southeastern Massachusetts, additional lateral system improvements would be needed to render firm service to the Cape Cod location.[66]

Locations that required more than one pipeline to provide a firm path include the Central CT, SW CT, Cape Cod, SE MA, Maine, Long Island, New York City, and Colbert locations.

The FT rate for each location is indicated in Table 11-18.

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[65] See Texas Eastern's TEAM 2014 Project certificate application at FERC, Docket No. CP13-84. These facility improvements will create 600 MDth/d of incremental firm capacity to markets along Texas Eastern's mainline – 300 MDth/d will be deliverable to the Lambertville and Staten Island, 50 MDth/d will be deliverable to Lebanon, OH, and 250 MDth/d will be deliverable to points in Mississippi and Louisiana. The major project facilities will be located in Pennsylvania, and include 33.5 miles of new 36-inch pipeline and a net increase of 77,100 HP of compression at various locations. Other modifications will accommodate bi-directional flow along the mainline. The planned in-service date is November 1, 2014. The facilities are estimated to cost $520 million. Chevron U.S.A., Inc. and EQT Energy, LLC have each contracted for 300 MDth/d of incremental transportation capacity.

[66] The incremental cost to bolster "G" system deliverability is $2.06/Dth-mo.

Table 11-18. FT Rates by Location

Location	Pipeline	Expansion Project	FERC Docket	Total Rate ($/Dth-mo.)	Supply Basin
Central CT	Algonquin Texas Eastern	AIM TEAM 2014	CP14-96 CP13-84	56.55	Marcellus/Utica
SW CT	Tennessee	CT Expansion Northeast Supply Diversification	CP14-529 CP11-30	25.89	Marcellus/Utica
Cape Cod	Algonquin Texas Eastern	AIM TEAM 2014	CP14-96 CP13-84	56.55	Marcellus/Utica
SE MA	Algonquin Texas Eastern	AIM TEAM 2014	CP14-96 CP13-84	56.55	Marcellus/Utica
Maine	PNGTS M&N[69]	C2C[67]		74.83[68]	Atlantic Canada
New Hampshire	Tennessee	Northeast Energy Direct		39.26[70]	Marcellus/Utica
Vermont	Tennessee	Northeast Energy Direct		39.26	Marcellus/Utica
New York City	Constitution Iroquois	New pipeline	CP13-499	30.72[71]	Marcellus/Utica
Long Island	Constitution Iroquois	New pipeline	CP13-499	30.72	Marcellus/Utica

[67] C2C facility modifications are expected to be minor. Therefore, the PNGTS system rate of $40.2456/Dth-month has been used as a proxy.

[68] All conversions between USD and CAD are based on an exchange rate of 1.1047 CAD/USD, per the exchange rate published September 22, 2014 by the Bank of Canada.

[69] A facility at the Maine location using M&N for transportation to supply upstream of PNGTS would need to pay two rates to move gas on M&N, $16.7292/Dth-month for the U.S. portion of the pipeline and CAD $20.8162/GJ-month.

[70] Rates for NED are not yet available. LAI has utilized twice the proposed Constitution rate filed in FERC Docket CP13-499 as a proxy for both the Vermont and New Hampshire locations.

[71] For both Long Island and New York City, the total rate is the sum of the Constitution rate filed in CP13-499 plus the current effective tariff rate on Iroquois.

Location	Pipeline	Expansion Project	FERC Docket	Total Rate ($/Dth-mo.)	Supply Basin
Lower Hudson Valley	Millennium	Hancock Compressor	CP13-14	19.77[72]	Marcellus/Utica
Capital District	Tennessee	Northeast Supply Diversification	CP11-30	6.52	Marcellus/Utica
Upper Peninsula	Northern Natural	N/A		14.88	West Texas
Twin Cities	Northern Natural	N/A		14.88	West Texas
Southern Illinois	NGPL	N/A	CP11-547[73]	9.99	Gulf
Dominion North	Transco	Atlantic Sunrise		23.73[74]	Gulf
PEPCO	Transco	Atlantic Sunrise		23.73	Gulf
BGE	Columbia	East Side Expansion	CP14-17	11.29	Marcellus
Delmarva	Texas Eastern	TEAM 2014	CP13-84	13.98	Marcellus
PECO	Transco	Leidy Southeast	CP13-551	20.50	Marcellus
PSEG North	Transco	Leidy Southeast	CP13-551	20.50	Marcellus
PSEG South	PennEast	New pipeline		18.25[75]	Marcellus
Maury East	Texas Eastern	Access South		19.47[76]	Marcellus/Utica
Colbert	AlaTenn Tennessee	N/A		15.29	Gulf
Johnsonville	Tennessee	N/A		11.94	Gulf

[72] The most recent project on Millennium, the Hancock Compressor Station Project, did not lead to an increase in rates. Therefore the FT-1 rate was utilized.

[73] The most recent project on NGPL, the 2014 Storage Optimization Project, did not lead to an increase in rates. Therefore, the NGPL system rate was utilized.

[74] Indicative rate from open season announcement, March 14, 2014. See http://www.1line.williams.com/1Line/wgp/download?delvid=5611994&hfNoticeFlag=Y&hfDownloadFlag=false&hfFileName=download.html

[75] Indicative rate from open season announcement, August 11, 2014. See http://penneastpipeline.com/openseason/

[76] Indicative rate from open season announcement, August 29, 2014. See http://www.spectraenergy.com/content/documents/Projects/Access_South_Open_Season_Notice_-_FINAL_-_07.25.14.pdf

Location	Pipeline	Expansion Project	FERC Docket	Total Rate ($/Dth-mo.)	Supply Basin
Summer Shade	Columbia Gulf	Rayne Express		6.39[77]	Gulf
Central	TransCanada	N/A		45.48	Western Canada
East	TransCanada	N/A		47.93	Western Canada

[77] Indicative rate from open season announcement, December 3, 2013.
See https://www.columbiapipelinegroup.com/docs/default-source/nisource-documents/leachrayne-xpress-open-season.pdf

In addition to the incremental firm rates on interstate pipelines, generators located behind the LDC citygate would incur additional costs to ensure deliverability throughout the heating season at the local level. A proxy cost of local system improvements was formulated based on the capital cost to establish a direct connection with an interstate pipeline.

For each LDC-served location, a comparable pipeline project was identified as a cost proxy, assuming that similar labor, materials, land and permitting costs would apply to the new lateral. Table 11-19 lists the proxy project for each location. For each project, except the Long Island location, the post-construction cost variance filing was used as the basis for estimating the new lateral costs.

Table 11-19. Projects Used as Cost Proxies for New Lateral Connections

Location	Cost Proxy Project
SW CT	Kleen Energy Lateral Project
New York City	Eastchester Extension Project
Long Island	Eastern Long Island Expansion Project[78]
BGE	Rock Springs Expansion Project
PECO PSEG North PSEG South	Woodbridge Delivery Lateral Project

Pipeline material costs were adjusted to account for increases in the cost of steel from the proxy project in-service date to 2014, total pipeline costs were adjusted to account for differences in lateral length, and total project costs were adjusted to account for actual inflation rates from the project in-service date to 2014, and then for 2% inflation from 2014 to 2018. Lateral connections and estimated lateral costs (in 2018$) are summarized in Table 11-20.

[78] This project was filed with FERC in late 2001, but later withdrawn. Iroquois is currently developing a similar project to serve proposed gas-fired generation on Long Island, but it has not yet been filed with FERC. Therefore updated cost data are not available. In addition to the estimated costs for the proposed project as filed in 2001, $44 million was added based on legal costs incurred by Spectra during permitting of the Islander East Project, which followed a similar route in order to account for difficulties associated with permitting from Connecticut to Long Island Sound.

Table 11-20. Lateral Connections and Estimated Costs

Location	Pipeline Connection	Length (Miles)	Estimated Cost (2018$ millions)
SW CT	Tennessee	3.5	$42.2
New York City	Iroquois	0.8 (onshore) / 1.7 (marine)	$69.2
Long Island	Iroquois	12 (onshore) / 17 (marine)	$259.0
BGE	Columbia	19.5	$89.0
PECO	Transco	0.5	$10.0
PSEG North	Transco	0.4	$9.2
PSEG South	PennEast	1.3	$20.7

LAI notes that some generators have other contract options with third parties and pipeline companies that may be designed to provide premium hourly services, including the right to schedule gas non-ratably. Cost tradeoffs between traditional primary firm transportation service and premium hourly service as well as the relative availability of these services throughout the Study Region to meet the fuel assurance objective vary throughout the study region and have - not been evaluated in Target 4.

11.6.3.2 IT Volumetric Rates

The effective IT rate for each constrained location follows the supply path used for incremental FT service discussed above, including, where applicable, the IT rate where LDC service is required. Some of the locations require transportation on two pipelines. The total volumetric IT rate for each location is summarized in Table 11-21 below.[79]

[79] For those locations involving LDC service, LAI has not included any cost of LDC system upgrades. In some instances, LDCs might require a substantial up-front payment to provide a new generator with IT service of reasonable quality. Such payments are based on value as well as cost and are highly case specific, and their estimation is outside of the scope of this study.

Table 11-21. IT Rates

Location	Pipeline 1	Rate ($/Dth)	Pipeline 2	Rate ($/Dth)	LDC IT Rate ($/Dth)	Total IT Cost ($/Dth)
Central CT	Algonquin	0.24	Texas Eastern	0.19		0.43
SW CT	Tennessee	0.38			0.25	0.63
Cape Cod	Algonquin	0.31	Texas Eastern	0.19		0.50
SE MA	Algonquin	0.28	Texas Eastern	0.19		0.47
Maine	PNGTS	1.32	Tennessee	0.38		1.71
New Hampshire	Tennessee	0.38				0.38
Vermont	Tennessee	0.38				0.38
New York City	Transco	0.49			0.19	0.68
Long Island	Transco	0.49			0.24	0.73
Lower Hudson Valley	Millennium	0.65				0.65
Capital District	Tennessee	0.26				0.26
Upper Peninsula	Northern Natural	0.80				0.80
Twin Cities	Northern Natural	0.80				0.80
Southern Illinois	NGPL	0.39				0.39
Dominion North	Transco	0.42				0.42
PEPCO	Transco	0.42				0.42
BGE	Columbia	0.14			0.40	0.54
Delmarva	Texas Eastern	0.19				0.19
PECO	Transco	0.49			0.58	1.07
PSEG North	Transco	0.49			0.68	1.17
PSEG South	PennEast	0.49			0.68	1.17
Maury East	Texas Eastern	0.25				0.25
Colbert	AlaTenn	0.11	Tennessee	0.40		0.52
Johnsonville	Tennessee	0.40				0.40
Summer Shade	Columbia	0.15				0.15
Ontario Central	TransCanada	1.50				1.50
Ontario East	TransCanada	1.58				1.58

11.6.3.3 Net Cost of FT

For the purposes of this analysis, the relevant cost of FT for a constrained location is the annual charges payable on a fixed, reservation basis to the pipeline(s), plus any direct-connect lateral cost where the supply chain must be firmed up behind the LDC gate station.80 The fixed costs payable to the pipeline, and, if applicable, the LDC, are then reduced by the avoided charges for non-firm transportation service otherwise payable to the pipeline and, if applicable, an LDC. Consistent with the reliability focus of this study, there is no adjustment to the cost of FT to

[80] Laterals assumed to allow direct deliveries from an interstate pipeline under IT service are treated as identical to the laterals required for FT at locations where IT deliveries are not via an LDC. Therefore, the cost of these laterals is not a relevant differential cost.

reflect the possible savings in natural gas commodity cost during periods of congestion. Non-firm transportation service and IT charges are used synonymously in the context of computing the net cost of FT.[81] Avoided IT charges are incurred as volumetric costs on the quantity of non-firm transportation purchased by the generator each operating year. The quantity of non-firm transportation supports the operating regime of the CC or SC. Hence, the total cost for non-firm transportation at any one of the 27 assumed locations is a function of the anticipated level of dispatch during hours when IT is available. Working in consultation with the PPAs, the anticipated dispatch level of the CC is assumed to be 5x16, 52 weeks a year, for an annual capacity factor of 47.6% before adjustments for gas deliverability. The anticipated level of the SC is assumed to be 5x8, 52 weeks a year (an unadjusted annual capacity factor of 23.8%).

The annual net cost of FT (ANCFT) can be estimated as the annual FT reservation charges less the annual cost of IT service:

$$ANCFT = \{MDQ * FTRR * 12\} - \{MDQ * ITVR * ACF * (365 - IntDays)\}$$

Where MDQ = maximum daily quantity (Dth/day)
FTRR = Effective firm transportation reservation rate ($/mo per Dth/d)
IntDays = Estimated days of IT service interruption per year
ACF = Annual capacity factor (based on dispatch ignoring interruptions)
ITVR = Effective interruptible transportation volumetric rate ($/Dth)

The net cost of FT can also be expressed on a unit basis (in $/month per Dth/day) as follows:

$$UNCFT = \{FTRR\} - \{ITVR * ACF * (365 - IntDays) / 12\}$$

These net costs are summarized in Figure 11-4 below. Detailed breakouts of the components of net FT cost are shown for each PPA in Figure 11-5 through Figure 11-10. Exhibit 30 presents the quantitative data underlying these figures.

[81] Imbalance resolution costs or differential penalty exposure under non-firm transportation arrangements have not been included in the derivation of the net cost of FT.

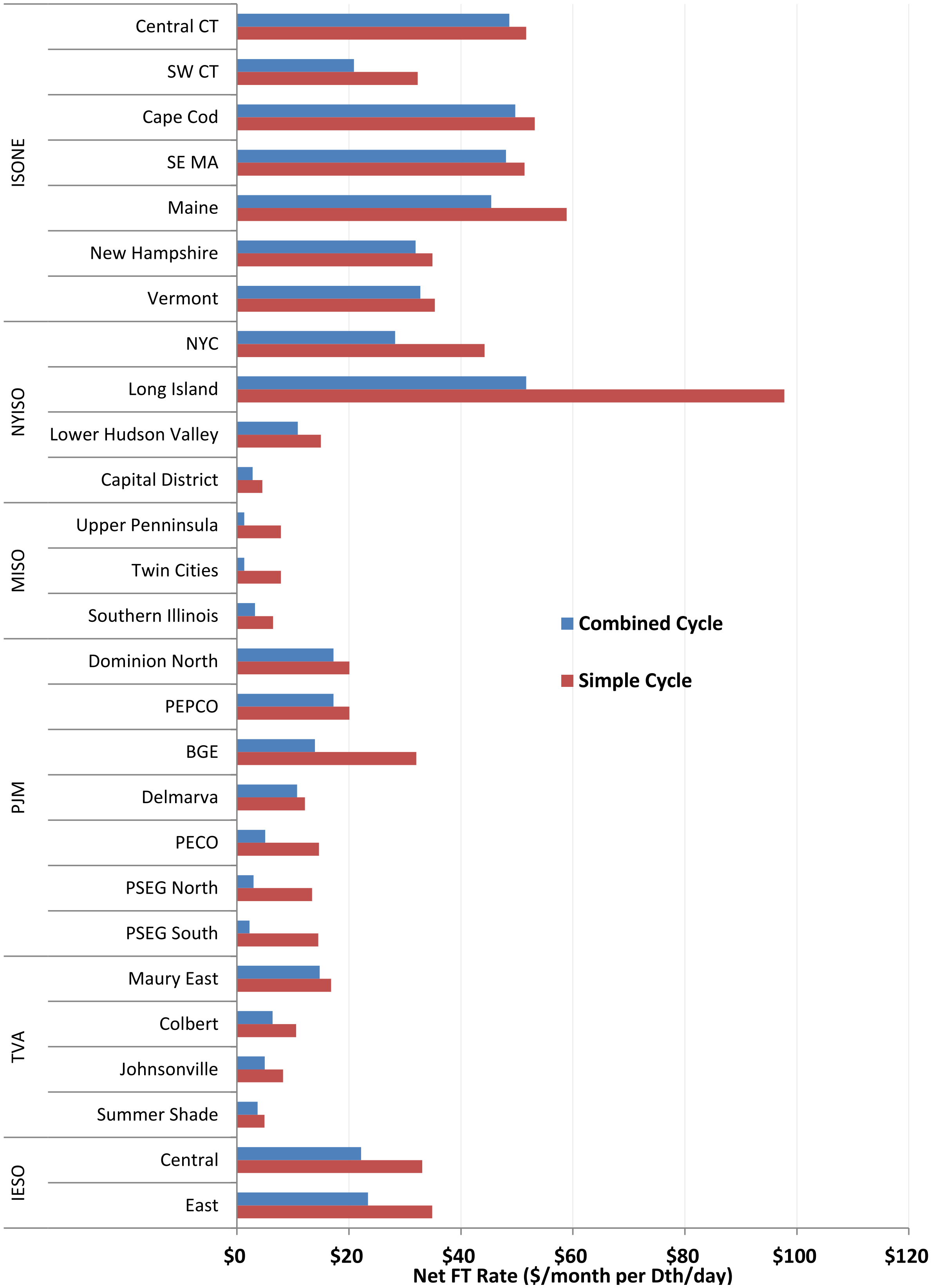

Figure 11-4. Net Cost of Firm Transportation by Location and Generator Type

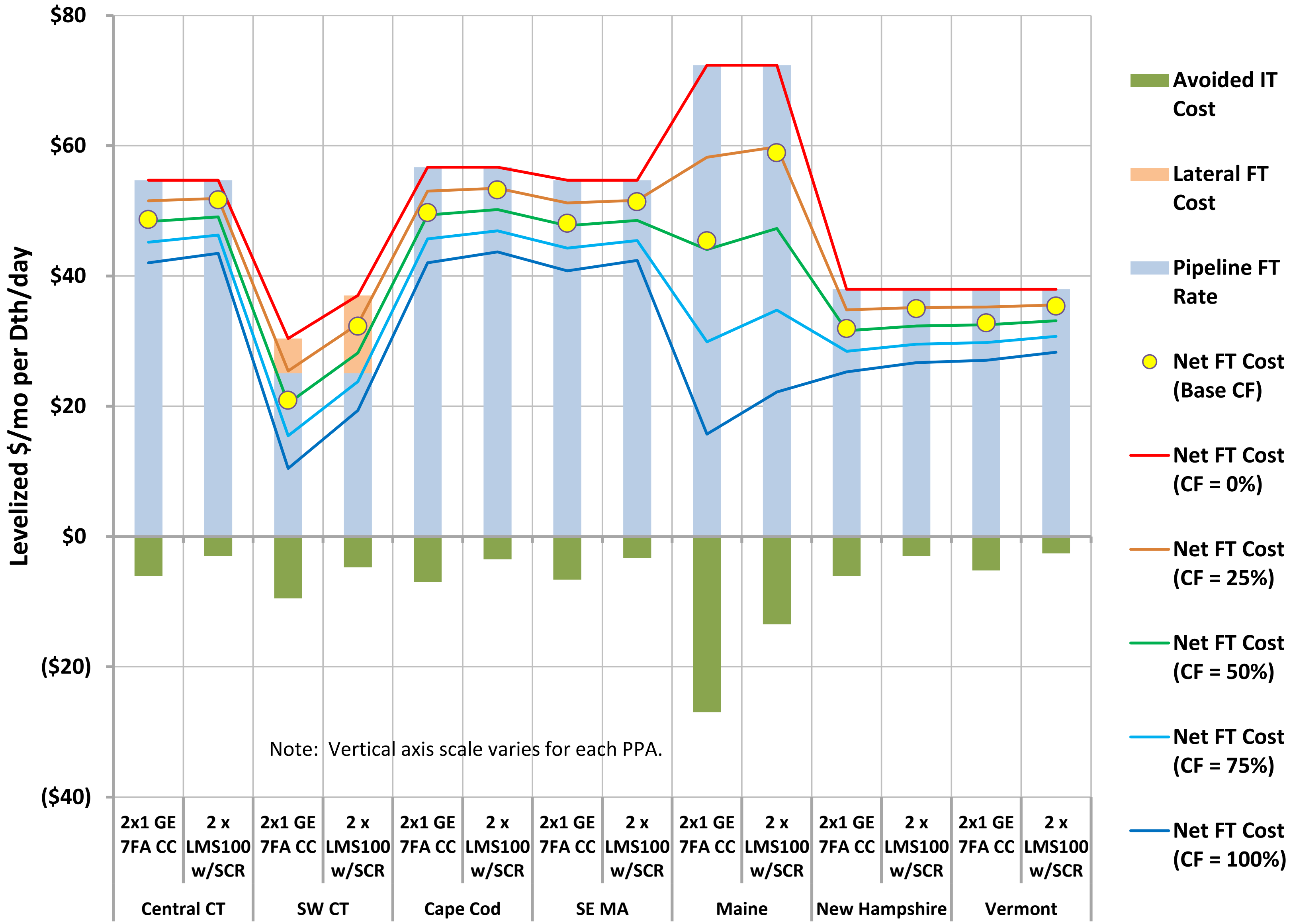

Figure 11-5. Net Cost of FT – ISO-NE Locations

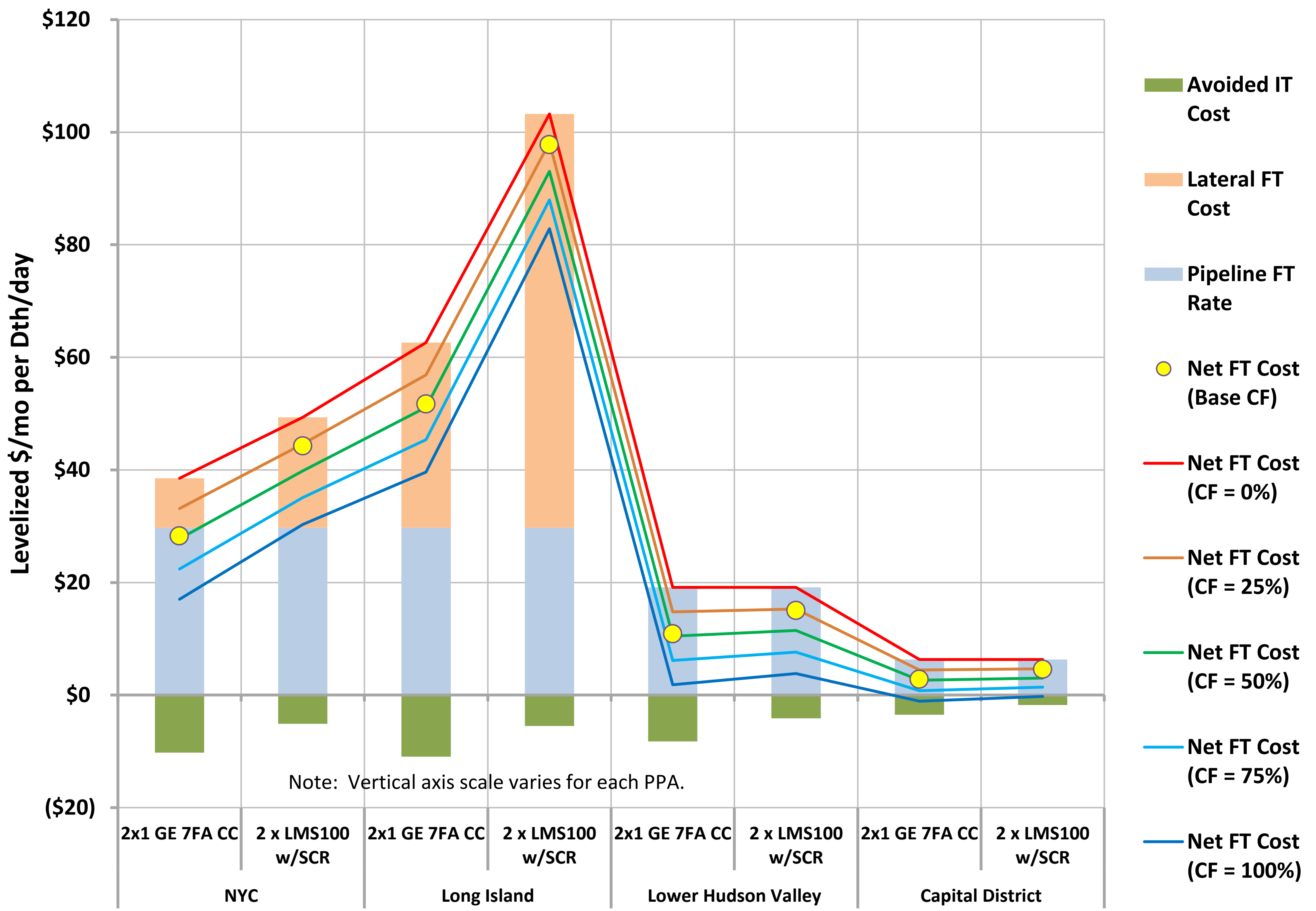

Figure 11-6. Net Cost of FT – NYISO Locations

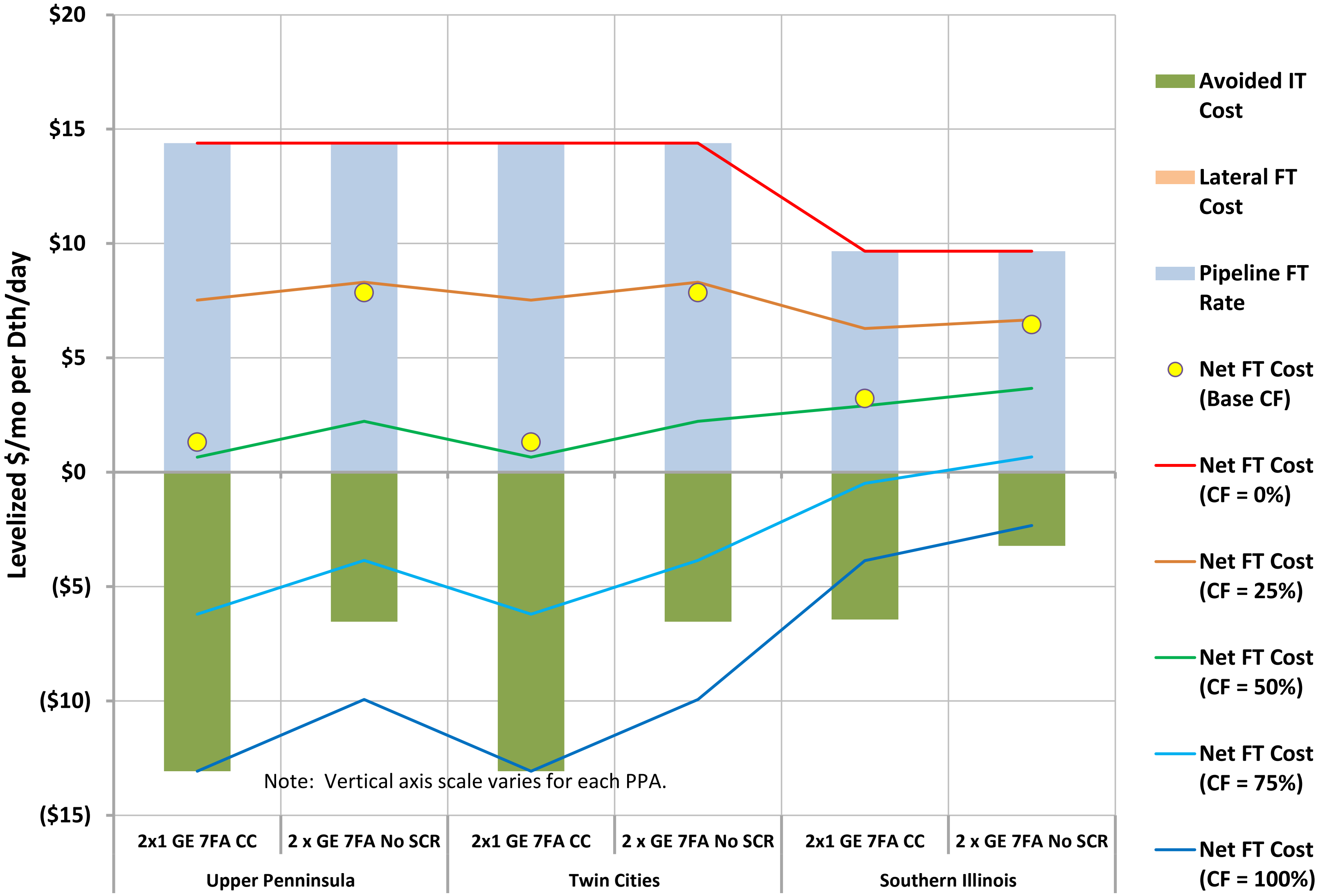

Figure 11-7. Net Cost of FT – MISO Locations

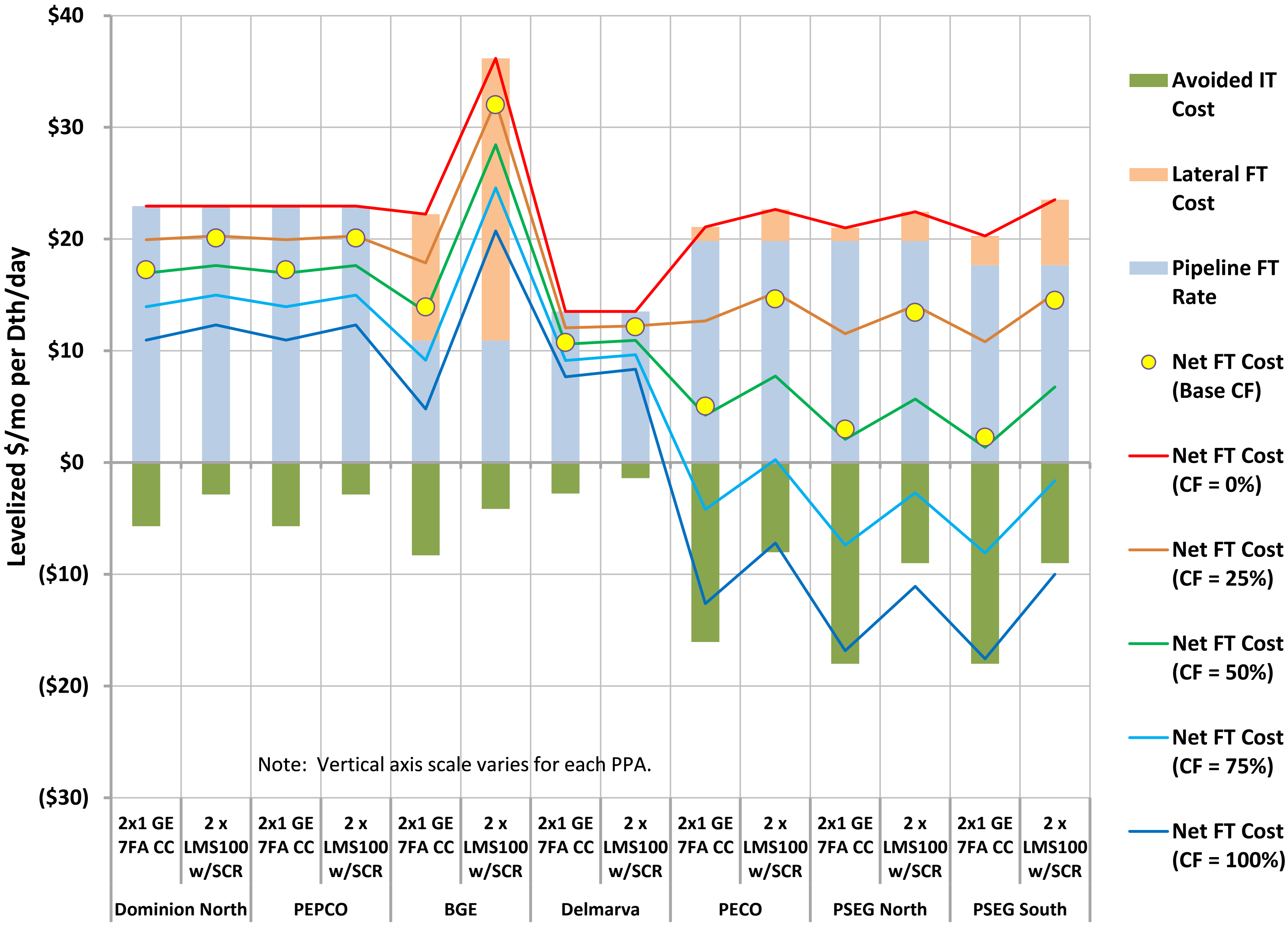

Figure 11-8. Net Cost of FT – PJM Locations

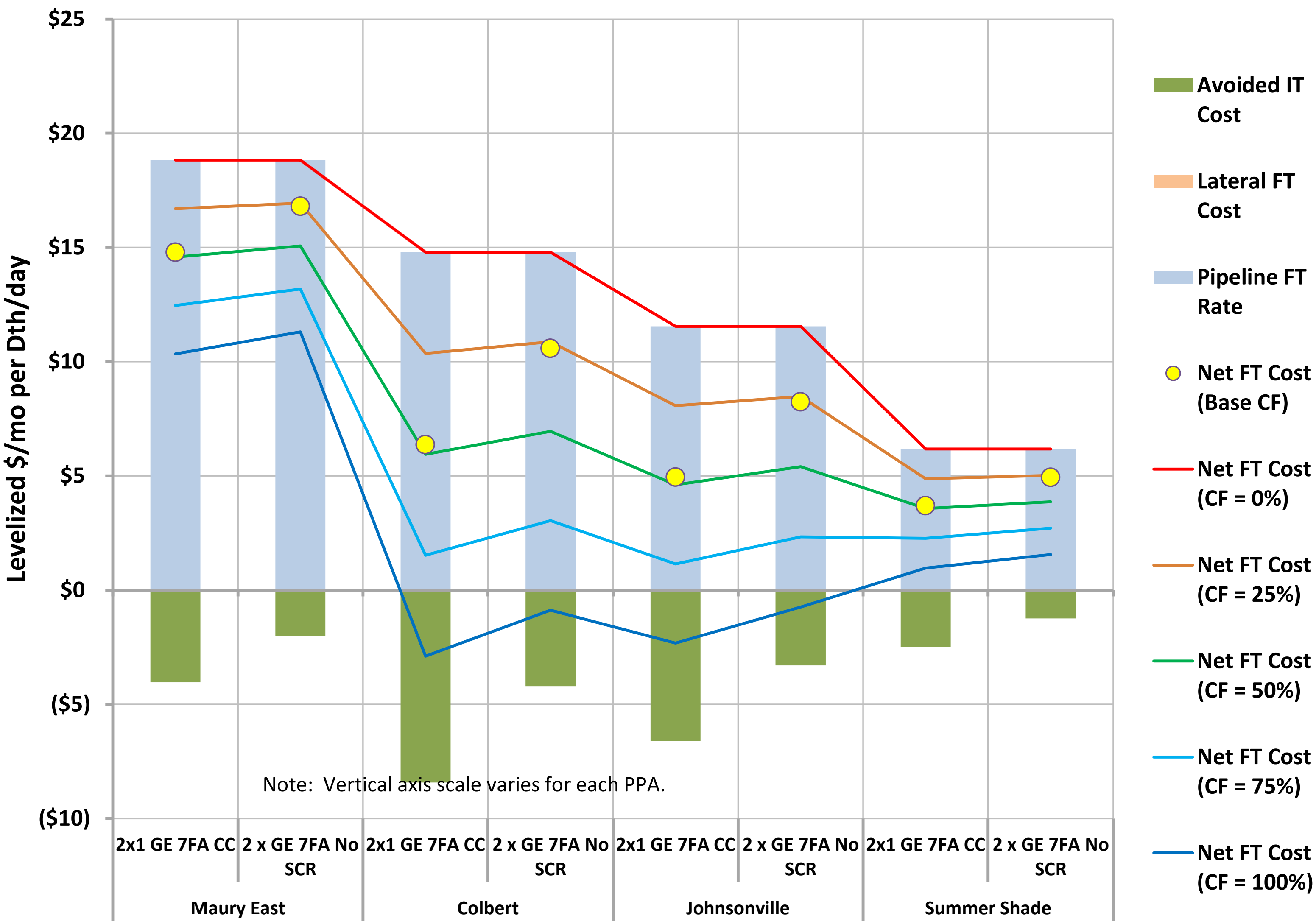

Figure 11-9. Net Cost of FT – TVA Locations

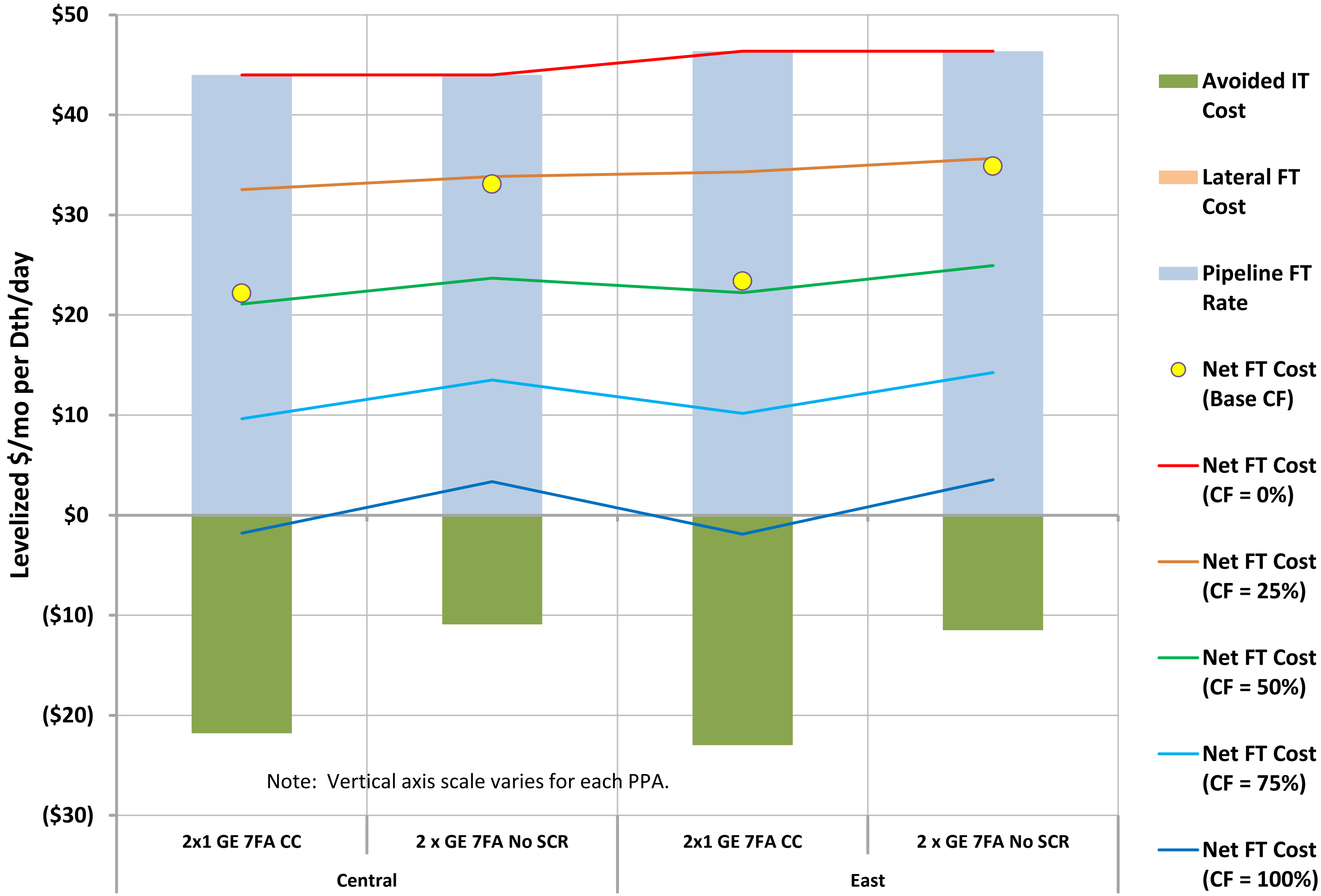

Figure 11-10. Net Cost of FT – IESO Locations

11.6.4 ULSD Logistics by Location

LAI identified the most likely depot for sourcing ULSD, the most likely transportation mode (truck or barge), and the distance from the depot to each of the 27 locations. We identified the current "rack" wholesale price for each depot and estimated delivery time adders based on transportation mode and distance. We also estimated the time to deliver a first shipment after an order was placed for each location, considering the transportation mode and distance, and a reasonable upper limit on transportation interruptions due to severe winter conditions. This information is summarized in Table 11-22 and Table 11-23.

The ULSD resupply assumptions and costs utilized as inputs to this analysis are based in part on information summarized in earlier sections of this report and on information obtained from published and industry sources. Barge and truck delivery costs are based on published rates and are generally consistent with information furnished by the PPAs, generators, and ULSD transporters. The cost of truck deliveries assumed 8,000 gallons per load and included: a 30% fuel surcharge, pump off costs of $48 per delivery, federal spill tax, and 1 hour of demurrage.[82] The cost of demurrage is computed at $75/hour beyond the unloading time of 30 minutes, including 10 minutes for positioning.[83] Tank truck unloading time is based on 400 gallons per minute at the plant storage facility.[84] Barge delivery costs included: a boom fee of $400 per delivery, federal spill tax, and 24 hours of demurrage. The cost of barge demurrage is assumed to be $250/hour beyond the 18 hour allowed delivery time.[85] The barge delivery capacity was assumed to be 840,000 gallons.[86]

The ULSD prices utilized for the plant locations analyzed with truck deliveries were obtained from published Oil Price Information Service (OPIS) rack prices for the terminals nearest the plant locations.[87] Prices for locations resupplied by barge deliveries in the Northeast were based on New York Harbor prices and for the TVA locations served by barge deliveries the base prices are Gulf Coast waterborne shipments.

[82] Demurrage is the charge imposed by the barge owner for time that the barge is held at a shipper's facility beyond a specified allowance.

[83] A. Protopapas, C. Kruse, L. Olson, Texas Transportation Institute, The Texas A&M University System, "Modal Comparison of Domestic Freight Transportation Effects on the General Public," 15 November 2012.

TransWood Logistics Rules & Regulations, www.transwood.com.

[84] Colfax Fluid Handling brochure, "Terminal Fluid Handling Solutions."

[85] Argus Petroleum Transportation North America Methodology and Specifications Guide, May 2014.

Merlin Petroleum Barge Rates, www.merlinpetroleum.com.

[86] A. Larkin, "Shipping oil and its impact on your cost of product," www.hedgesolutions.com.

[87] OPIS publishes 30,000 rack prices daily from almost 400 terminals throughout North America.

Table 11-22. ULSD Logistics by Location

No.	PPA	Location Name	Depot Location	Rack Price ($/gal)	Delivery Mode	Delivery Cost ($/gal)
1	ISO-NE	Central CT	NY Harbor	$2.74	Barge	$0.06
2	ISO-NE	SW CT	NY Harbor	$2.74	Barge	$0.04
3	ISO-NE	Cape Cod	NY Harbor	$2.74	Barge	$0.06
4	ISO-NE	SE MA	NY Harbor	$2.74	Barge	$0.06
5	ISO-NE	Maine	NY Harbor	$2.74	Barge	$0.08
6	ISO-NE	New Hampshire	Chelsea, MA	$2.84	Truck	$0.05
7	ISO-NE	Vermont	Rutland, VT	$2.91	Truck	$0.06
8	NYISO	New York City	NY Harbor	$2.74	Barge	$0.00
9	NYISO	Long Island	Inwood, NY	$2.78	Truck	$0.05
10	NYISO	Lower Hudson Valley	NY Harbor	$2.74	Barge	$0.05
11	NYISO	Capital District	Albany, NY	$2.80	Truck	$0.04
12	MISO	Upper Peninsula	Cheboygan, MI	$2.88	Truck	$0.09
13	MISO	Twin Cities	St. Paul, MN	$2.85	Truck	$0.04
14	MISO	Southern Illinois	Cape Girardeau, MO	$2.80	Truck	$0.05
15	PJM	Dominion North	Fairfax, VA	$2.76	Truck	$0.04
16	PJM	PEPCO	Fairfax, VA	$2.76	Truck	$0.04
17	PJM	BGE	NY Harbor	$2.74	Barge	$0.06
18	PJM	Delmarva	Delaware City, DE	$2.77	Truck	$0.04
19	PJM	PECO	Philadelphia, PA	$2.76	Truck	$0.04
20	PJM	PSEG North	Newark, NJ	$2.77	Truck	$0.04
21	PJM	PSEG South	Trenton, NJ	$2.80	Truck	$0.04
22	TVA	Maury East	Nashville, TN	$2.79	Truck	$0.05
23	TVA	Colbert	New Orleans, LA	$2.71	Barge	$0.09
24	TVA	Johnsonville	New Orleans, LA	$2.71	Barge	$0.09
25	TVA	Summer Shade	Nashville, TN	$2.79	Truck	$0.08
26	IESO	Central	Toronto, ON	$2.81	Truck	$0.04
27	IESO	East	Kingston, ON	$2.87	Truck	$0.04

11.6.5 ULSD Inventory Level and Tank Capacity

LAI has estimated the size of backup liquid fuel inventory and storage tank capacity for a dual-fuel capable power plant.[88] We formulated the storage tank "bogie" for ULSD, which is the most appropriate back-up fuel for combustion turbines in simple or combined cycle applications. In developing the bogie, LAI relied on the Target 2 results and considered the following factors that would affect the PPAs' backup fuel requirements and the generator's investment decision

[88] Optimizing tank size and fuel inventory requires multi-faceted mathematical analysis of PPA-specific reliability goals, weather conditions, gas delivery risks, plant-specific operating characteristics, and transportation replenishment logistics that are beyond the scope of the research goals and objectives for this analysis.

vis-à-vis FT service. The factors we considered include: (i) the frequency and duration of gas interruption, (ii) the delay between back-up fuel request and initial delivery, (iii) the risk of back-up fuel delivery delays, and (iv) expected dispatch.[89]

LAI's calculation approach is presented in Appendix 42. Results are summarized in Table 11-23 below. In general, plants that utilize barge deliveries have large tank sizes, roughly equivalent to 3x24 storage for simple cycle plants and 6x24 for combined cycle plants. Plants utilizing truck deliveries that are relatively close to storage terminals have tank sizes consistent with our database of 1-2x24 for simple cycle plants and 2-3x24 for combined cycle plants.

These results are consistent with the following values:

- The 2014 PJM CONE report assumed 3x24 of ULSD capacity for SC and CC plants. The 2013 NYISO CONE Study did not specify the tank size or oil inventory level.

- According to a September 17, 2014 Con Edison presentation to the NYISO Electric-Gas Coordination Working Group, dual-fueled generators receiving gas from Con Edison must demonstrate 5x24 of backup fuel (some may be off-site) prior to the winter season to permit Con Edison to comply with NYSRC Local Reliability Rule I-R3 governing system operations.

- PJM is developing a Capacity Performance product to enhance system reliability in light of the fuel problems encountered during the January 2014 Polar Vortex. The generator availability requirements of Capacity Performance may necessitate generators having 3x16 of on-site or backup fuel capability.

In Figure 11-11, total tank capacity, including an allowance above the target inventory level to accommodate the delivery of a barge when otherwise full is shown for each location for the CC and SC configuration. Capacities are presented in days of full load burn rate. Details are shown for each PPA in Figure 11-12 through Figure 11-17. Exhibit 31 presents the quantitative data underlying these figures.

Target inventory levels and tank volumes, expressed in days of full load fuel burn, are generally larger for CC plants than for SC plants because of the higher capacity factor, offset to some degree by a lower heat rate. For those locations with assumed barge delivery, target inventory is higher due to the generally longer delivery times, relative to truck delivery. The allowance for the capacity of one barge further increases the tank volume at barge locations.

[89] Gas-fired generators will base the decision to invest in dual-fuel capability in response to PPA (dis)incentives affecting performance, and other economic considerations, including penalty tolerance and return on investment.

Table 11-23. Inventory and Tank Size Calculations by Location

			TIL (days at Average Load)				CC TIL & Tank Vol (days at Full Load)		
No.	**PPA**	**Location**	**Gas Constraint**	**Delivery Lag**	**Weather Delay**	**Total**	**Target Inventory Level**	**Barge Size Allowance**	**Fuel Tank Volume**
1	ISO-NE	Central CT	3	1	3	7	3.3	1.3	4.6
2	ISO-NE	SW CT	3	6	3	12	5.7	1.3	7.0
3	ISO-NE	Cape Cod	3	6	3	12	5.7	1.3	7.0
4	ISO-NE	SE MA	3	6	3	12	5.7	1.3	7.0
5	ISO-NE	Maine	2	9	3	11	6.7	1.3	8.0
6	ISO-NE	New Hampshire	2	1	3	6	2.9	0.0	2.9
7	ISO-NE	Vermont	3	2	5	10	4.8	0.0	4.8
8	NYISO	New York City	2	5	3	11	4.8	1.3	6.1
9	NYISO	Long Island	2	1	3	11	2.9	0.0	2.9
10	NYISO	Lower Hudson Valley	3	7	3	7	6.2	0.8	7.0
11	NYISO	Capital District	3	1	3	7	3.3	0.0	3.3
12	MISO	Upper Peninsula	0	2	5	7	3.3	0.0	3.3
13	MISO	Twin Cities	0	1	3	4	1.9	0.0	1.9
14	MISO	Southern Illinois	0	1	3	4	1.9	0.0	1.9
15	PJM	Dominion North	1	1	3	5	2.4	0.0	2.4
16	PJM	PEPCO	1	1	3	5	2.4	0.0	2.4
17	PJM	BGE	2	8	3	11	6.2	1.3	7.5
18	PJM	Delmarva	3	1	3	7	3.3	0.0	3.3
19	PJM	PECO	3	1	3	7	3.3	0.0	3.3
20	PJM	PSEG North	1	1	3	5	2.4	0.0	2.4
21	PJM	PSEG South	1	1	3	5	2.4	0.0	2.4
22	TVA	Maury East	0	1	3	4	1.9	0.0	1.9
23	TVA	Colbert	0	17	3	9	9.5	0.8	10.3
24	TVA	Johnsonville	0	17	3	4	9.5	0.8	10.3
25	TVA	Summer Shade	0	2	3	5	2.4	0.0	2.4
26	IESO	Central	1	1	3	5	2.4	0.0	2.4
27	IESO	East	1	1	3	5	2.4	0.0	2.4

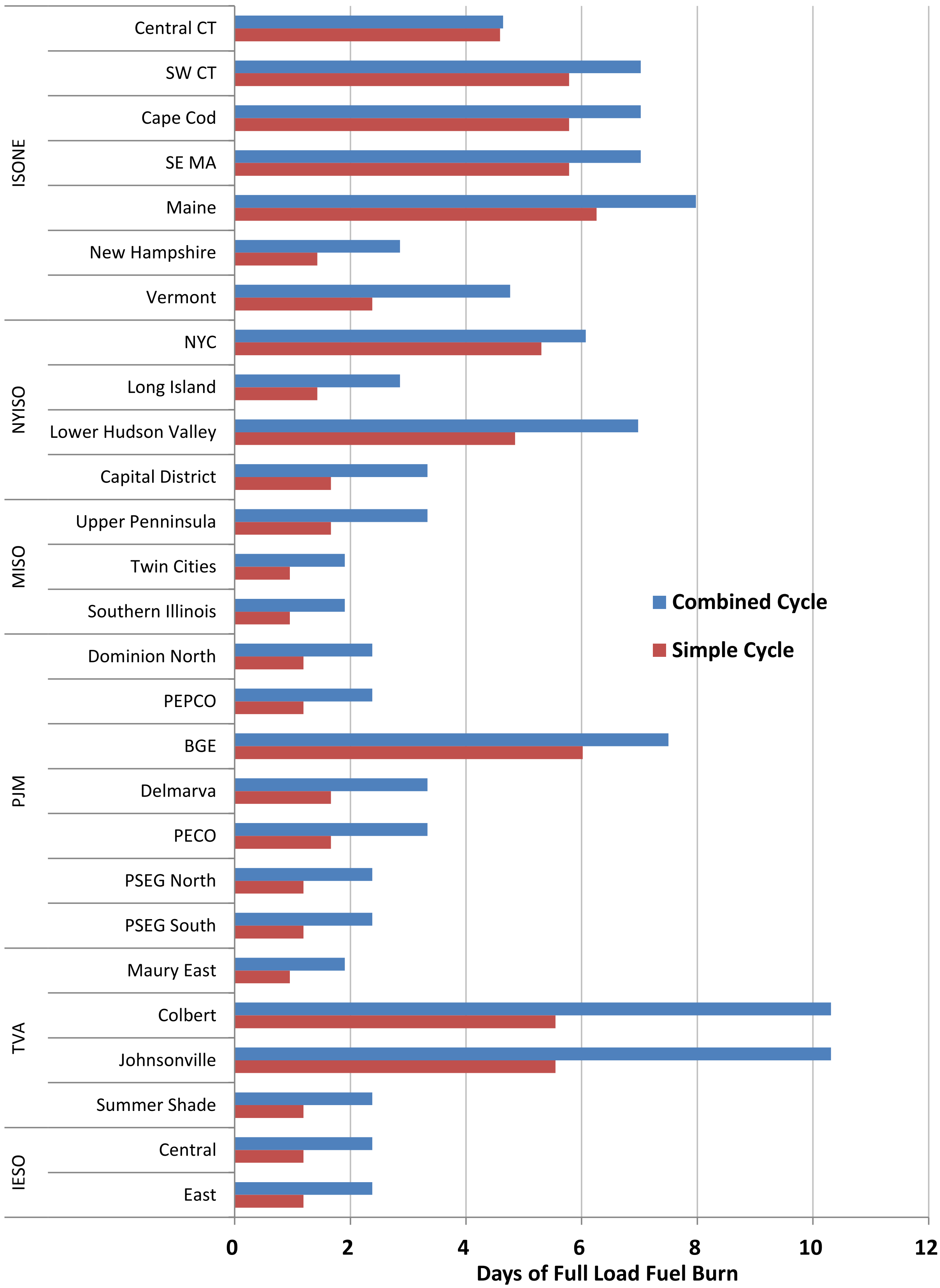

Figure 11-11. ULSD Tank Capacities

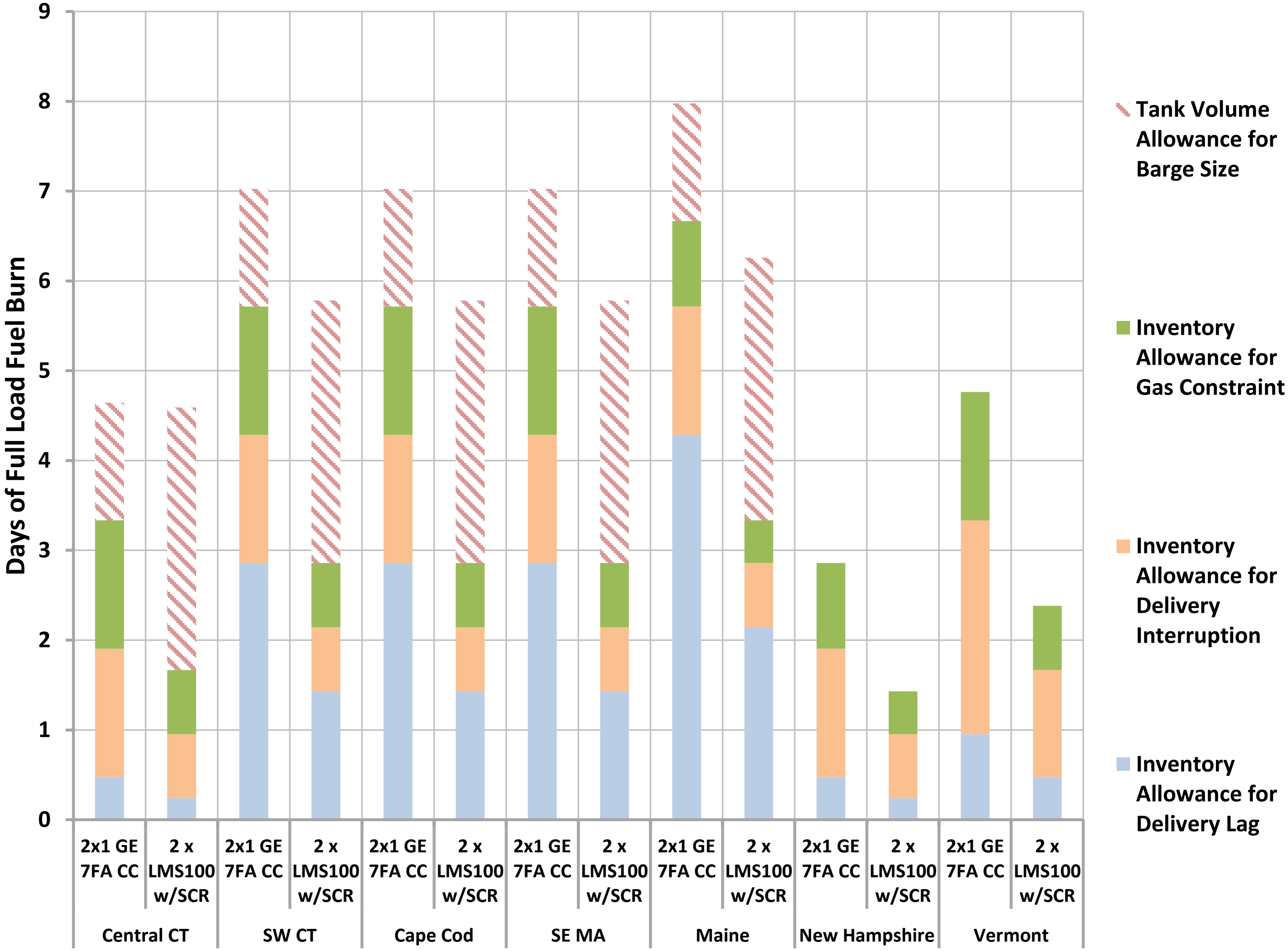

Figure 11-12. Tank Size Calculations – ISO-NE Locations

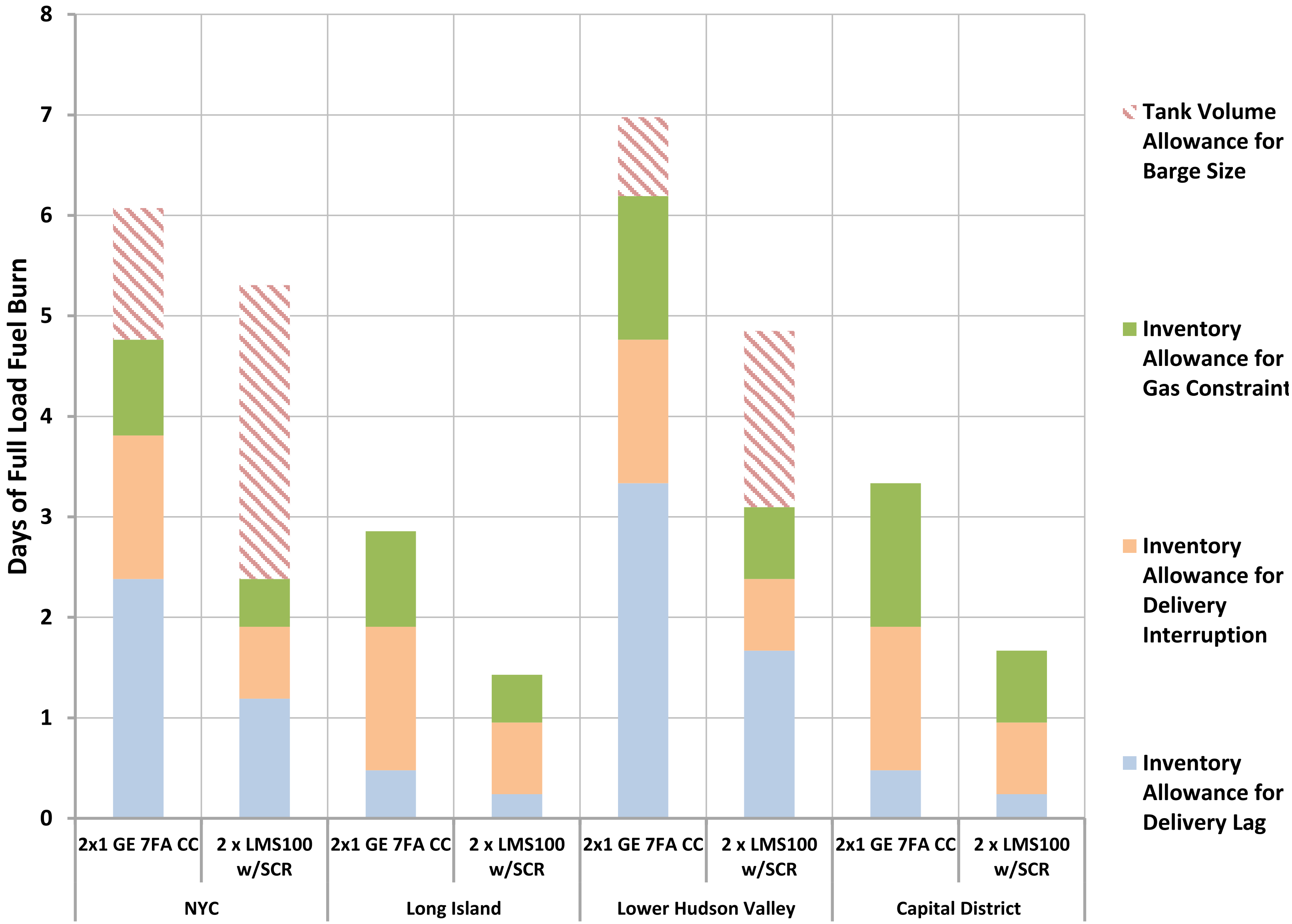

Figure 11-13. Tank Size Calculations – NYISO Locations

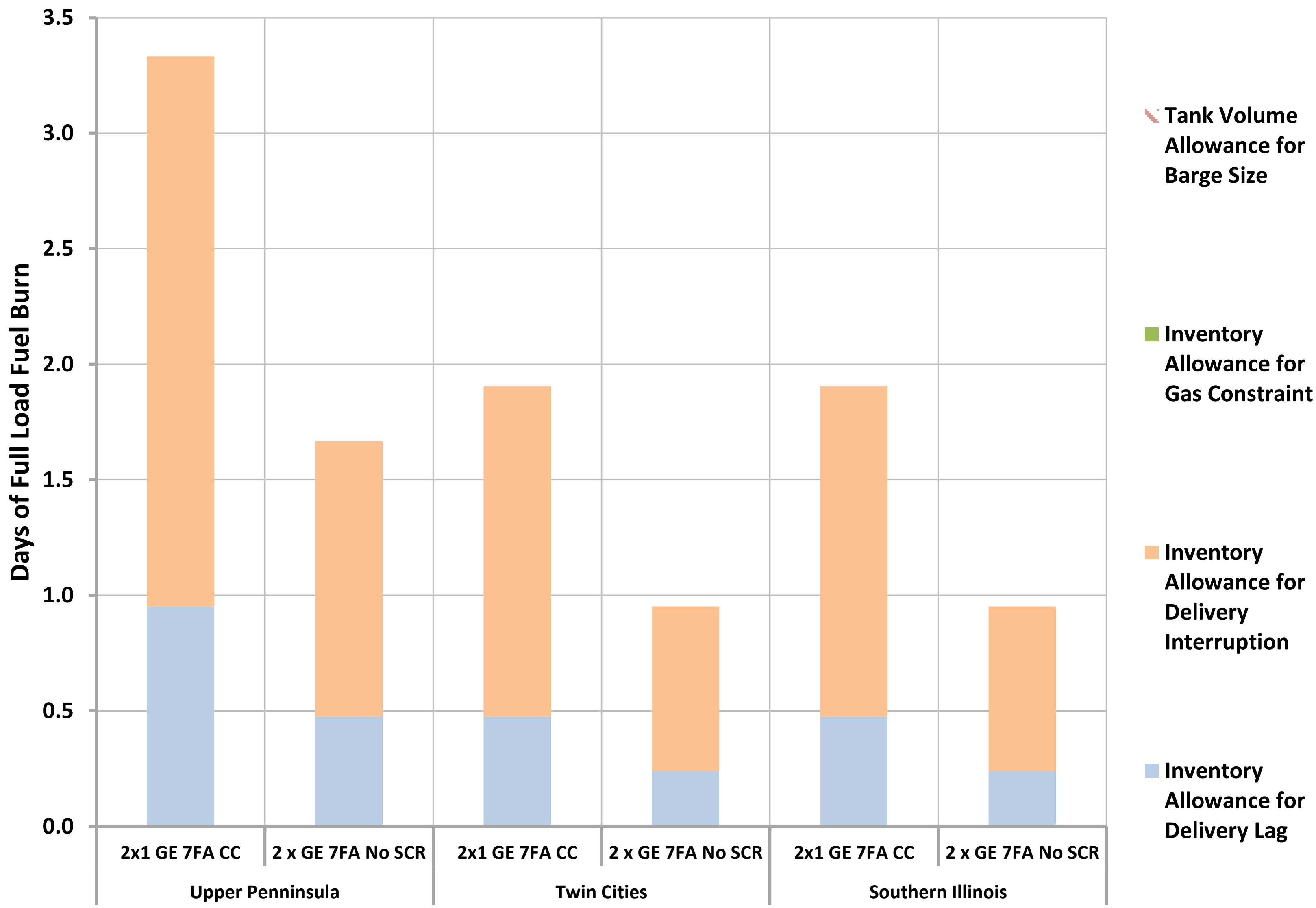

Figure 11-14. Tank Size Calculations – MISO Locations

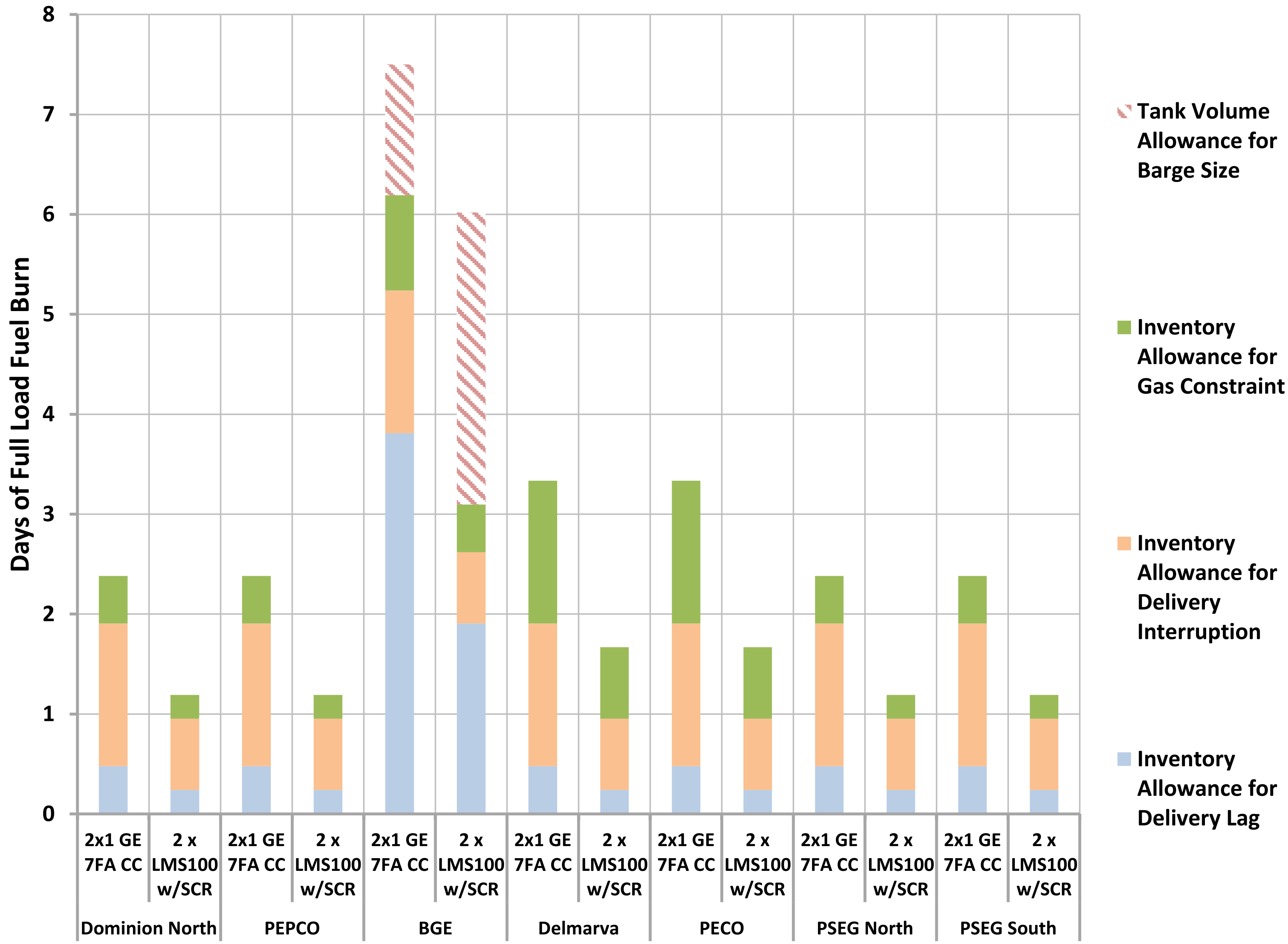

Figure 11-15. Tank Size Calculations – PJM Locations

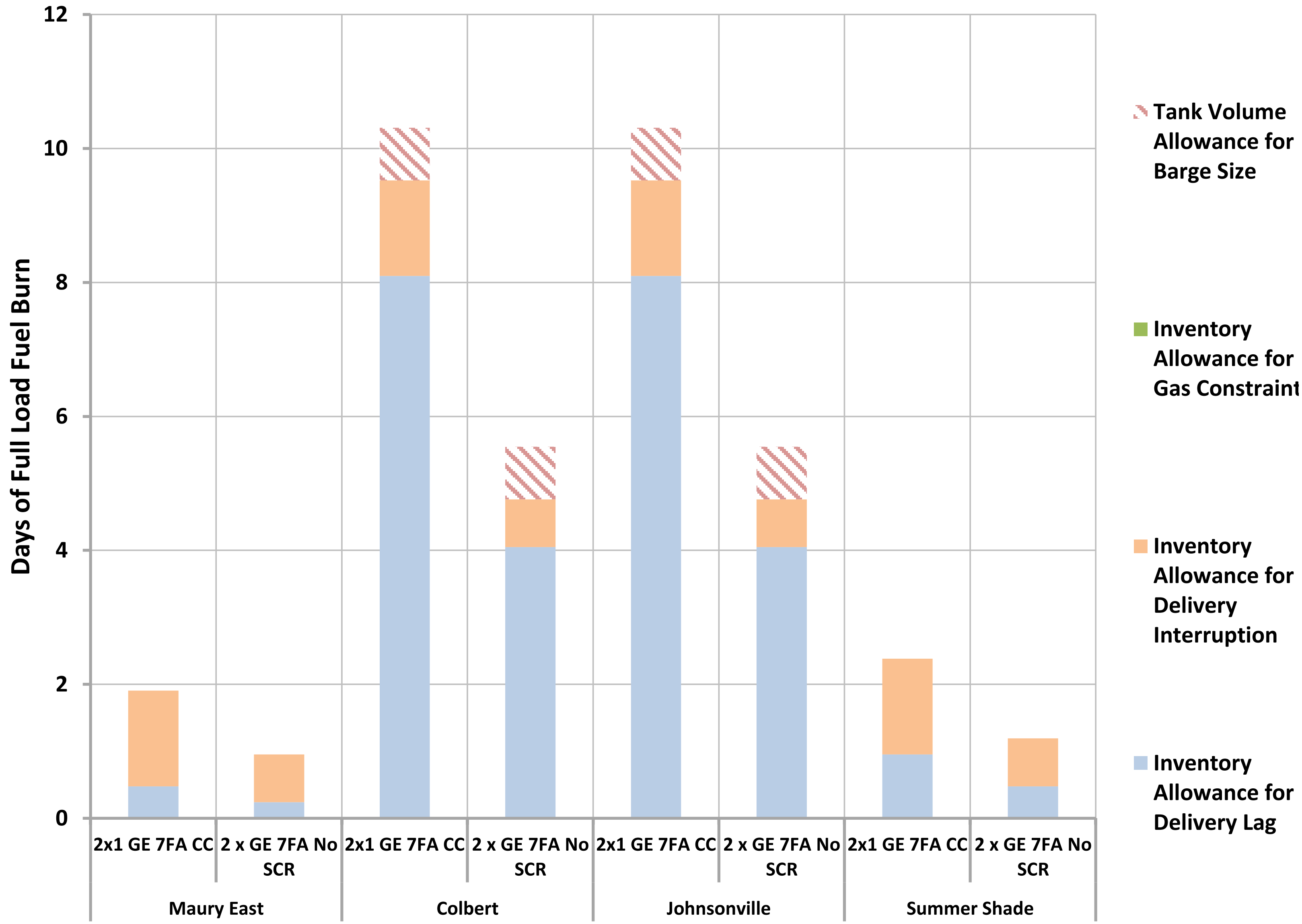

Figure 11-16. Tank Size Calculations – TVA Locations

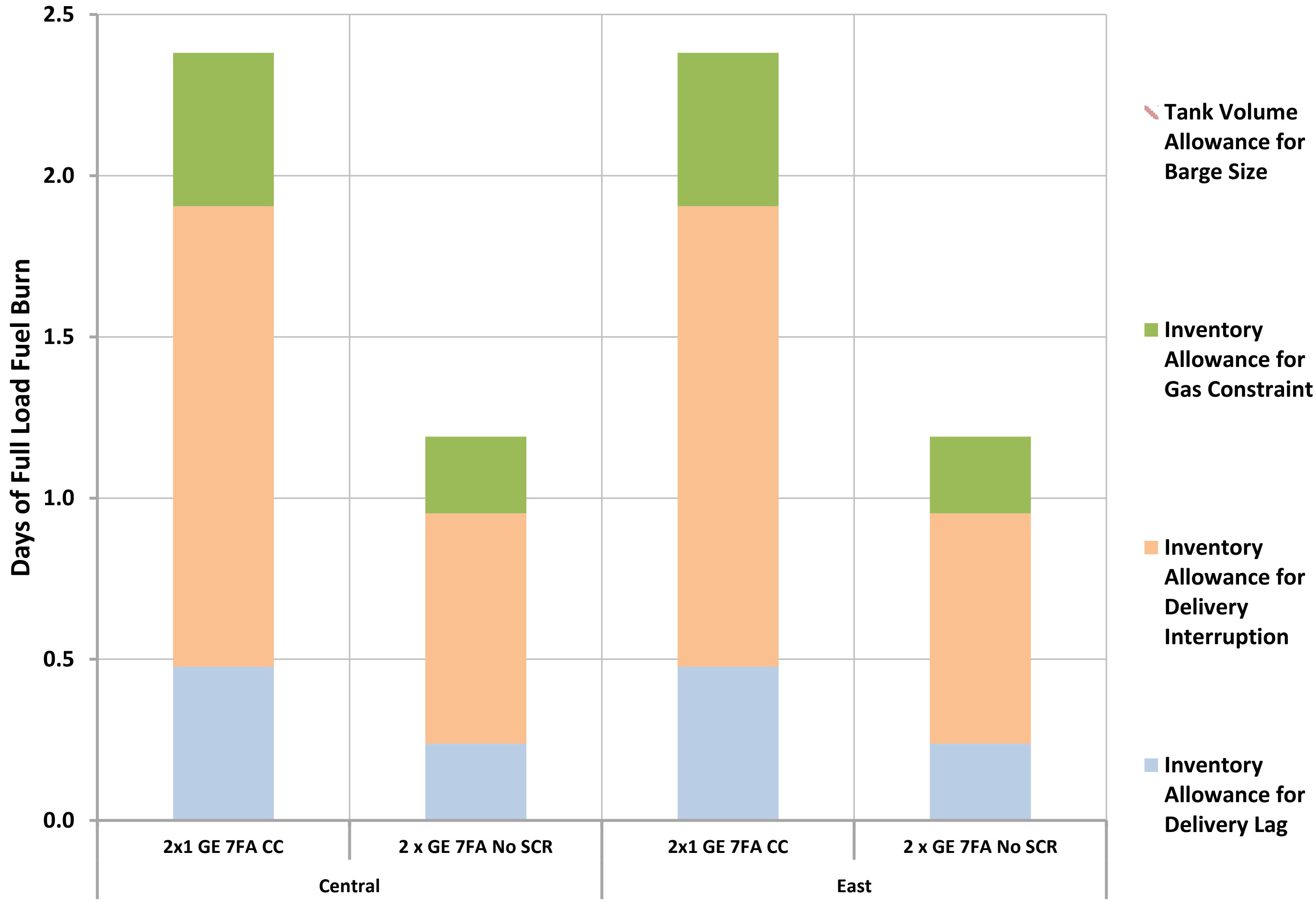

Figure 11-17. Tank Size Calculations – IESO Locations

11.6.6 Key Location Characteristics

Using the cost model described in Section 11.3, LAI researched key characteristics of each location from public sources to support our dual-fuel cost calculations. We incorporated other financial assumptions to produce a levelized annual cost for each of two fuel assurance options. The characteristics are discussed below, and the actual values of the characteristic for each location are included in the detailed cost model printouts in Exhibit 32.

11.6.6.1 National Ambient Air Quality Attainment Status of Location

Each location was classified with respect to the local area's attainment of the NAAQS for the 8-hour ozone standard, as follows:[90]

- Locations in counties which are designated non-attainment for ozone, are subject to requirements under NA NSR and must meet the LAER standard for NOx control. They must also obtain ERCs if the annual NOx emissions will be equal to or greater than the significance level, which depends on the severity of non-attainment. The ratio of offsets to annual emissions must be between 1.15 and 1.3, depending on state regulations and the severity of the non-attainment. Locations which are located in the OTR, even if they meet the NAAQS for ozone, are considered moderate non-attainment and must meet these same requirements to prevent deterioration of ambient air quality ("backsliding").

- Locations that are in counties designated as attainment are subject to the less stringent PSD requirements, must meet the BACT standard, and do not need to obtain ERCs.

The attainment status determines the selected technology for simple cycle CT plants and whether ERCs for NO_x would have to be purchased by a plant developer.

CC technology for all locations is assumed to meet LAER and BACT requirements and consists of 2x1 GE 7FA with dry-low NO_x (DLN) combustion technology for natural gas, water injection in the SCs for ULSD, and SCR located in the HRSG. This technology achieves NO_x emission rates of 2 ppm or on natural gas and 6 ppm on ULSD.

SC technology for locations in non-attainment areas is assumed to be a 2xLMS100 aeroderivative CT with SCR. These units are treated as LAER for peaking units and achieve emission rates of 2.5 ppm on natural gas and 5.9 ppm on ULSD. For locations in attainment areas, the assumed technology is the 2x7FA heavy frame CTs without SCR. Assuming DLN for natural gas and water injection for ULSD, this configuration achieves NO_x emission rates of 9 ppm on natural gas and 42 ppm on ULSD.

For locations in non-attainment areas, the incremental quantity of offset purchases required (ton/yr) for a dual-fuel plant (relative to gas-only) is determined as the net difference in emission

[90] NAAQS for other priority pollutants, such as $PM_{2.5}$, were also considered. However, the annual emissions from the plant of those pollutants are unlikely to exceed the significance level which would require offsets.

rate (expressed as lb/MWh) for ULSD and the rate firing natural gas multiplied by the winter capacity (MW) and 720 hours per year and divided by 2,000 lb/ton.

ERCs for NO_x are assumed to cost $15,000 per ton/yr, multiplied by the applicable offset ratio. Actual costs vary geographically and over time, but this price represents a reasonable median. The total cost of ERCs for a location and technology are treated as additional capital requirements associated with dual-fuel capability. Incremental ERC costs for CC plants in non-attainment areas are roughly $500,000. For the 2xLMS100 SC plant in non-attainment areas the incremental offset costs are approximately $170,000.

11.6.6.2 Elevation and Reference Ambient Conditions

While elevation above sea level and the range of annual ambient temperatures affect CT performance, none of the locations were considered to be high enough in elevation or to have temperatures extreme enough to cause significant variations in the differential operational performance between gas and ULSD. Therefore, we have used sea level performance data, summer capability at 90°F, winter fuel requirements at 20ºF, and testing fuel requirements and output at 59ºF (ISO) for all locations.

11.6.6.3 Labor Cost Adjustment Factor

The Cost Model uses Cleveland, Ohio as a base for labor costs. For this analysis, LAI developed a relative cost factor for each location using a combination of resources. The primary driver of relative costs is the Department of Labor Wage Rate report.[91] We used the labor wage data for key power plant construction trades such as plumber, electrician, pipefitter, and structural steel worker to develop a relative wage index for the relevant states. For states with a wide range of labor wages, we used a report of power plant costs by major city published by the U.S. Energy Information Administration to get location-specific adjustment factors.[92] For the two Ontario locations, we used construction wage data from Statistics Canada (similar to the US Department of Labor Wage Rate data) and applied contemporary exchange rates to express those costs in US dollars.[93] The resulting labor cost adjustment factors ranged from a low of 0.852 for Yarmouth, Maine to a high of 1.558 for New York City.

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[91] Bureau of Labor Statistics, Occupational Employment Statistics, http://www.bls.gov/oes/current/oessrcst.htm. Canada Labour Program, Ontario – Northeast/Northwest Zone: Schedule of Wage Rates, http://www.labour.gc.ca/eng/standards_equity/contracts/schedules/ontario/north_zone/schedule.shtml.

[92] "Updated Capital Cost Estimates for Electricity Generation Plants", U.S Energy Information Administration Office of Energy Analysis, Washington DC, November 2010.

[93] http://www5.statcan.gc.ca/cansim/a26 Table 327-0003 Construction Union Wage Rates.

11.6.6.4 Industrial Land Cost

We based the power plant land costs on the PJM CONE Study and the NYISO Demand Curve Reset Study, with adjustments for other locations. Land costs range from $5,000 per acre in isolated areas to $850,000 per acre in New York City. This input turns out to be a relatively small component of the incremental cost of dual-fuel capability at most locations, since the fuel and demineralized water tanks require only about one acre of additional land.

11.6.6.5 Sales Tax Rate

State and local sales taxes on equipment and materials can add a significant amount to a power plant capital cost, as seen in the PJM CONE Study. LAI determined sales tax rates for the 27 locations using a database by zip code.[94] US rates vary from 0% in New Hampshire and Delaware to 9.75% in Humphreys County, Tennessee. A "harmonized sales tax rate" of 13.0% for the Ontario locations was obtained from another website.[95]

11.6.6.6 Property Tax Rate

Property taxes on incremental plant assets are a significant portion of fixed O&M. LAI obtained effective property tax rates for real property and personal property (equipment) for US locations using a report by the Lincoln Institute of Land Policy comparing property tax rates.[96] We confirmed these rates by checking the websites of various municipalities. We obtained property tax rates for the Ontario plant locations from municipal websites. Real property tax rates range from a low of 0.75% in Colbert County, Alabama to a high of 5.0% in New York City. The effective rates on personal property are zero in many locations, but range as high as 1.1%.

11.6.6.7 Corporate Income Tax Rate

The capital recovery charge rate needed to represent capital costs as levelized annual costs is a function of the effective corporate income tax rate, which includes federal, state, and local income taxes. The US federal rate is 35%. State and local tax rates were obtained from the Federation of Tax Administrators for the US locations and range from 6.0% in Kentucky and

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[94] http://www.taxrates.com/calculator, Avalara, Inc.

[95] http://www.taxtips.ca/salestaxes/sales-tax-rates-2013.html 2013 for sales tax rates for PST, GST, and HST in each province. The "harmonized" tax rate is collected as a single tax with proceeds allocated to federal and provincial governments.

[96] "50 State Property Tax Comparison Study", prepared for the Minnesota Taxpayers Association by Lincoln Institute of Land Policy, April 2011 (Downloaded from http://www.lincolninst.edu)

Michigan to 17.16% in New York City.[97] The effective combined federal and provincial rate for Ontario, Canada, is 26.5%.[98]

11.6.6.8 Energy Revenue from Liquid Fuel Testing

Liquid fuel testing is typically required during startup and on a regular basis during a plant's operating life. We included the cost of test fuel during startup (net of energy revenues) as a capital cost, and the cost of test fuel during operations (net of energy revenues) as a fixed operating cost. Since testing might occur at any time of year, LAI has used a representative time-weighted average energy price for each relevant zone from the RGDS S0 2018 AURORA simulation run. These energy prices range from $33.49/MWh in the Toronto, Ontario (US dollars) to $55.50/MWh for Long Island, NY.

11.6.7 Calculation of Levelized Annual Costs

We expressed the levelized annual costs for fuel assurance for both dual-fuel capability and FT service in level nominal dollars per kW-year (summer capacity rating) assuming a January 1, 2018 commercial operation date and a 20-year economic life. General inflation was assumed at 2% per year. Capital costs were estimated and adjusted to 2018 dollars, then multiplied by a capital charge rate reflecting common and location-specific financial assumptions. Fuel inventory carrying charges were based on the 2018 estimate of ULSD delivered cost and a pre-tax charge rate which includes an allowance for fuel oil escalation at 2% per year, the long-term average oil products escalation rate from the DOE EIA Annual Energy Outlook. Fixed O&M costs are converted from 2018 dollars to a levelized annual cost reflecting the 2% general inflation rate. All levelized annual costs are divided by the summer gas-fired capacity of the plant.

11.6.7.1 Common Financial Assumptions

We developed capital charge rates for plant costs using a traditional revenue requirements approach using the after-tax weighted cost of capital as a discount rate with the following assumptions common to all locations:

- Economic life of 20 years
- Cost of equity of 13.8% (nominal)
- Cost of debt (pre-tax) of 7.00% (nominal)
- Debt as fraction of capital (60%)

[97] "Range of State Corporate Income Tax Rates for tax year 2014", Federation of Tax Administrators, downloaded from http://www.taxadmin.org/fta/rate/corp_inc.pdf

[98] "Federal and Provincial/Territorial Rates for Income Earned by a CPCC Effective January 1, 2013 and 2014", KPMG LLP, 2013

- Tax depreciation of plant and equipment: 20-year life for combined cycle plants and a 15-year life for simple cycle plants

11.6.7.2 Location-Specific Financial Assumptions

We used the following location-specific assumptions in developing the capital charge rates for the dual-fuel alternative:

- The effective income tax rate is location-dependent, resulting in levelized nominal dollar capital charge rates for combined cycle plants ranging from 14.15% at the Ontario locations to 17.04% at the New York City location. The capital charge rates for simple cycle plants are slightly lower due to faster tax depreciation.

- Fuel inventory carrying charges are based on the same general and location-specific assumptions. We assumed that inventory cost is returned only at the end of the 20-year life, but at an escalated price. Levelized annual rates range from 16.06% in Ontario to 20.82% in New York City.

After-tax weighted average cost of capital (WACC) and levelized capital charge rates are shown for each location in the input section of Exhibit 32. Fixed O&M costs, expressed in 2018 $/year, are converted to levelized costs per kW of installed capacity using the assumed 2% inflation rate and the location-specific WACC.

The annual cost of FT was calculated in 2018 dollars as the product of the winter maximum hourly natural gas burn (Dth/h), 24 hours per day, 12 months per year, and the estimated reservation charge ($/month per Dth/day). This first year amount is treated as the levelized nominal dollar amount and divided by the summer installed capacity for expression as levelized $/kW-yr to allow comparison with the dual-fuel capability costs.

11.6.8 <u>Results</u>

This section presents the results of the calculations of levelized annual cost for fuel assurance through dual-fuel capability and through firm transportation service for natural gas. Detailed results of the cost comparisons for the 27 locations for both CC and SC generating plants are presented in Exhibit 32. Levelized annual costs are presented in nominal dollars per kW of installed (summer) capacity, assuming a 2018 commercial operation date and a 20-year capital recovery period.

11.6.8.1 Levelized Annual Cost of Dual-Fuel Capability

The levelized annual cost of dual-fuel capability includes capital recovery for incremental plant and equipment, additional owner's costs, financial carrying costs for liquid fuel, and incremental fixed O&M costs. The cost model described in Section 11.3 was expanded to include location-specific cost factors applicable to the 27 locations selected by the PPAs and to allow for the levelized cost comparisons. The resulting costs range from $8.24/kW-yr at the TVA Maury East location to $14.08/kW-yr at the TVA Johnsonville location. A breakout of levelized cost by its major components is provided for the locations selected by each PPA in the following subsections. Each sub-section includes a bar chart with the following components for CC and SC generation at each location:

- The bottom (blue) bar for each location represents recovery of the incremental capital cost of the combustion turbine supply package, which is a common capital cost for all locations. Differences among locations are minor and attributable to variations in the capital charge rate due to income tax effects.
- The second (green) bar represents capital recovery for the cost of tanks for ULSD and demineralized water. These costs are driven by location-specific inventory requirements as well as differences in labor costs and taxes.
- The third (purple) bar represents capital recovery for other construction costs, including forwarding systems for ULSD and demineralized water. These costs include a labor component which varies from location to location.
- The fourth (cyan) bar represents capital recovery for Emission Reduction Credits (ERCs or "offsets") required at some locations.
- The fifth bar (orange) represents capital recovery of the net cost of startup testing on ULSD. It is based on the assumed 72 hours of testing used in the PJM CONE analysis and reflects local market conditions.
- The sixth (brown) bar represents carrying charges on fuel inventory over the study period.
- The seventh (olive) bar represents fixed O&M labor, services, and materials costs.
- The eighth (light blue) bar represents the net cost of annual testing on ULSD.
- The ninth (pink) bar represents insurance costs and property taxes which are driven by capital cost and local tax rates.

11.6.8.1.1 ISO-NE Locations

Figure 11-18 shows a breakdown of levelized annual costs for dual-fuel capability for each of the ISO-NE locations. Costs per kW tend to be higher for the SC option at each location because of higher heat rates and correspondingly higher full load fuel burn rates only partially offset by lower required ULSD inventory levels based on lower expected dispatch levels. **Notably, potential utilization of a seasonal LNG service obtained from Suez Distrigas or Repsol Canaport was not examined in this study.** Costs are generally lower at the Central CT, and New Hampshire locations because truck delivery allows for lower inventory levels and tank capacities than barge delivery. All of the ISO-NE locations require the 2xLMS100 SC technology.

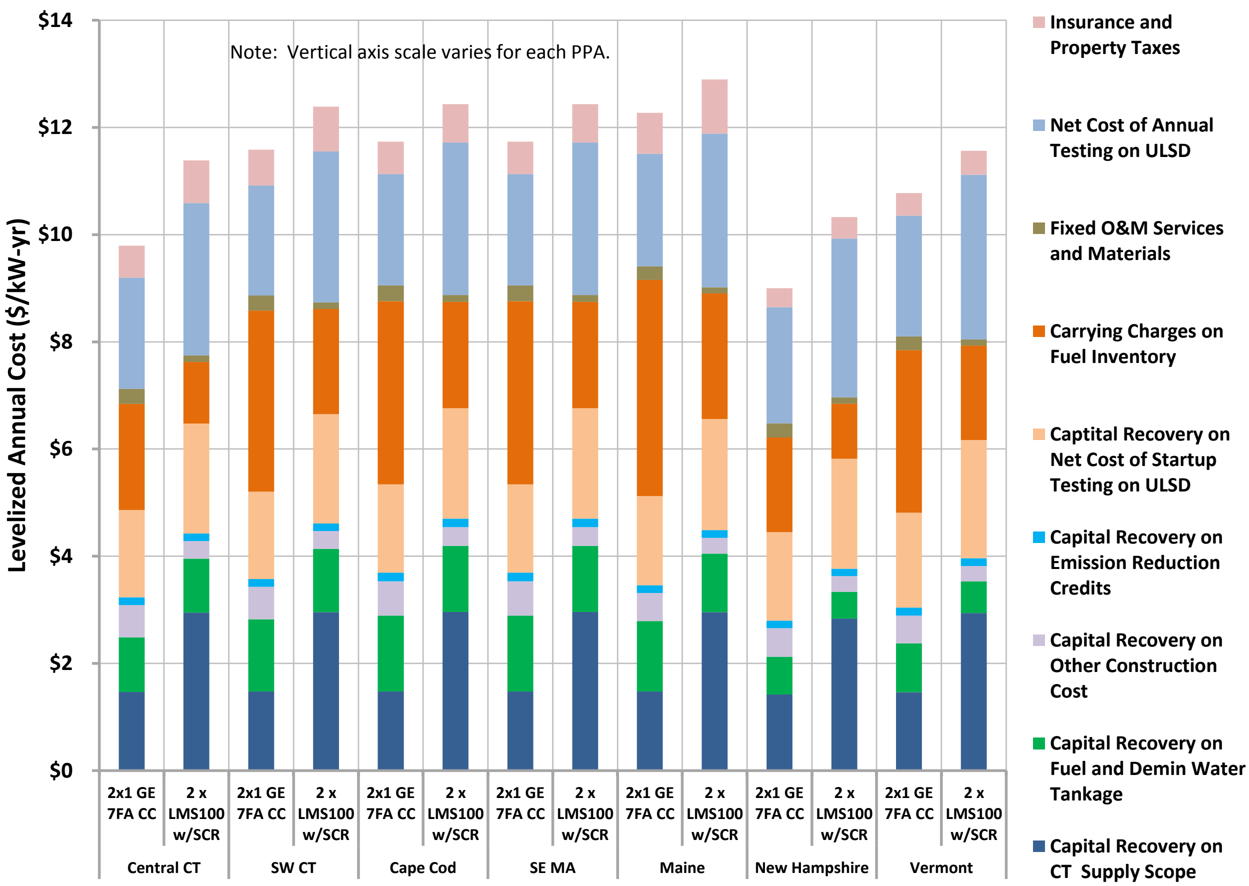

Figure 11-18. Dual-Fuel Cost Details for ISO-NE Locations

11.6.8.1.2 NYISO Locations

Figure 11-19 shows the dual-fuel capability costs for the locations selected by NYISO. As in New England, the barge delivery sites (New York City and Lower Hudson Valley) show higher fixed costs than the truck delivery locations, due to higher tank capacity and inventory requirements. All of the NYISO locations assume the 2xLMS100 SC technology.

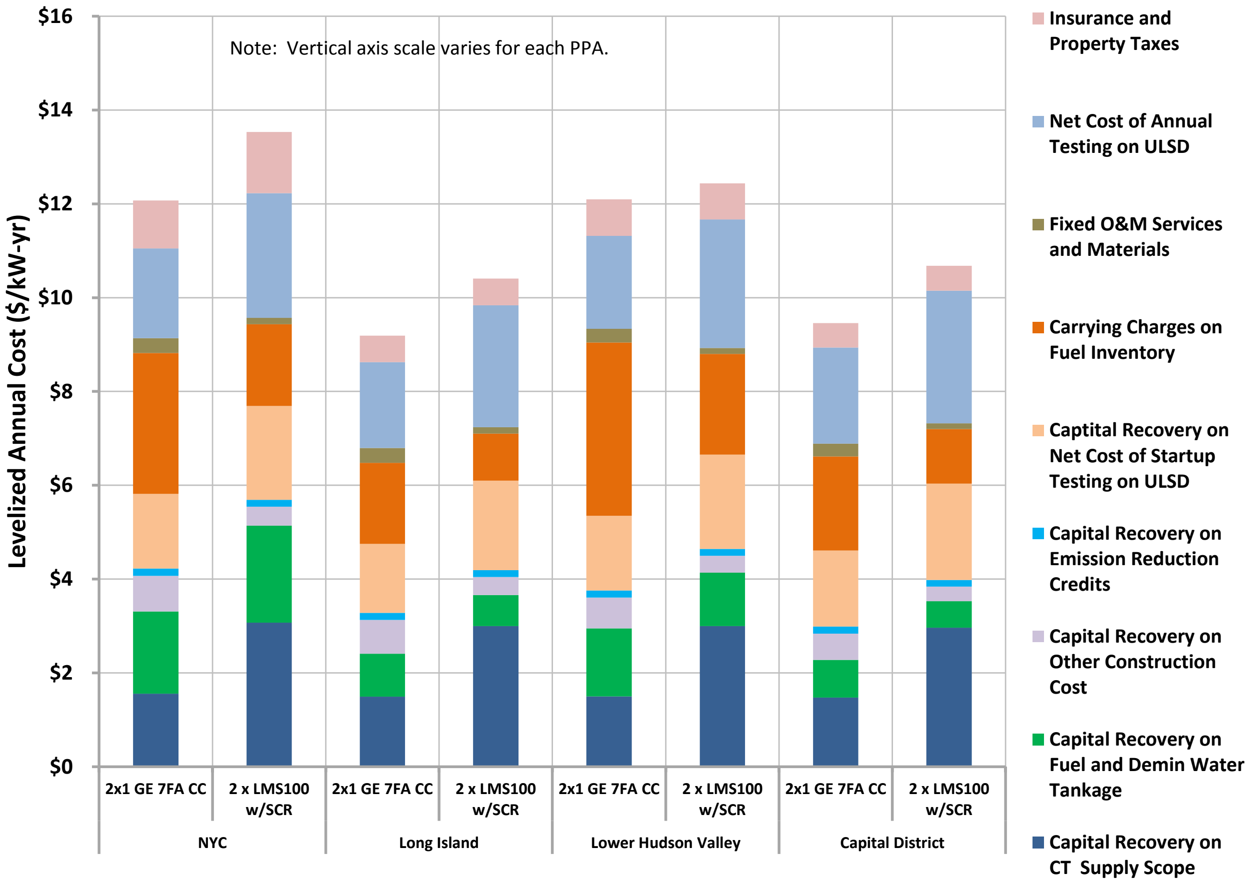

Figure 11-19. Dual-Fuel Cost Details for NYISO Locations

11.6.8.1.3 MISO Locations

Figure 11-20 shows the dual-fuel capability costs for the locations selected by MISO. All three locations assume truck delivery, and the principal driver of cost differences among the locations is distance from a ULSD supply depot. All of the MISO locations assume the 2x7FA SC technology.

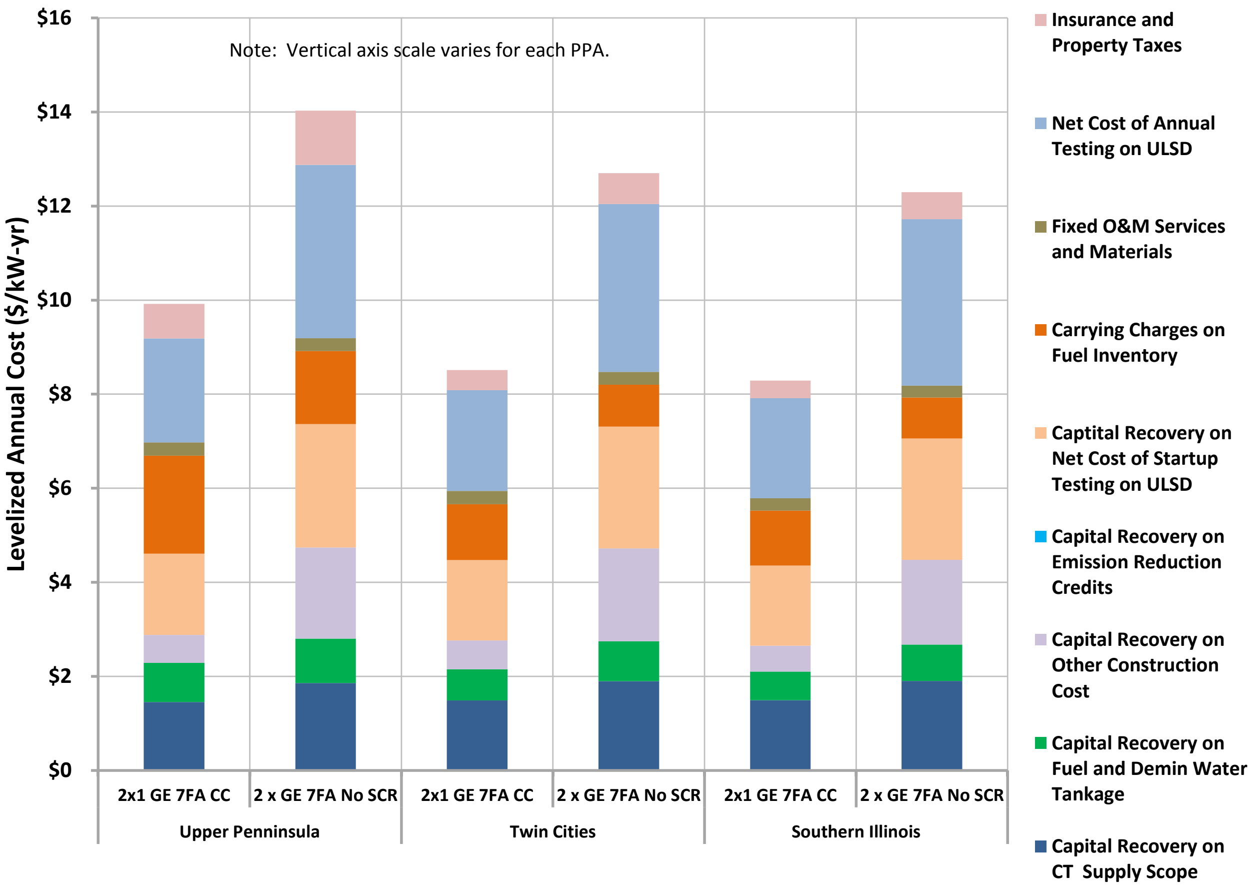

Figure 11-20. Dual-Fuel Cost Details for MISO Locations

11.6.8.1.4 PJM Locations

Figure 11-21, shows the components of dual-fuel capability cost for the locations selected by PJM. The total cost for the BGE locations (Baltimore) is higher than the others because barge delivery is assumed for that location,[99] but not for other PJM locations that are close to oil terminals, thereby warranting lower cost truck replenishment. The remaining locations are closely grouped for each generation type. All locations assume the 2xLMS100 simple cycle technology to comply with emission limits.[100]

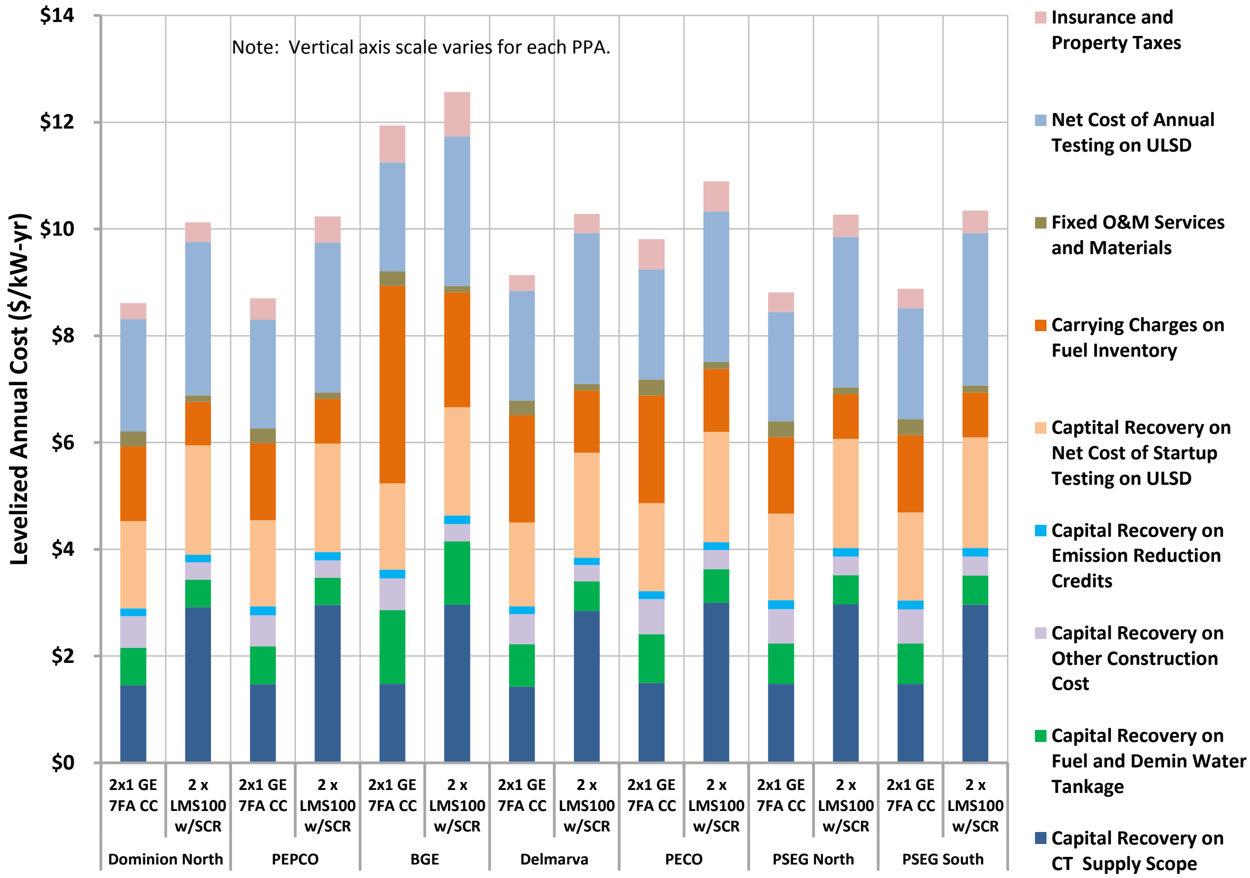

Figure 11-21. Dual-Fuel Cost Details for PJM Locations

99 Permitting constraints in Baltimore's inner harbor may significantly limit or otherwise preclude truck transported ULSD refill for new power plants.

100 The 2014 PJM CONE Study assumes GE 7FA CTs at all sites considered, regardless of NO_x attainment status. Most sites considered in that analysis required SCR for compliance with LAER. In this study, we have assumed that, if the site requires LAER, the 2xLMS100 configuration would be used.

11.6.8.1.5 TVA Locations

Figure 11-22 shows the components of dual-fuel cost for the locations selected by TVA. The wide variation among the locations is attributable to the effects of long-haul delivery by barge at the Colbert and Johnsonville locations and truck delivery at the East Maury and Summer Shade locations. The simple cycle technology is 2x7FA for each site.

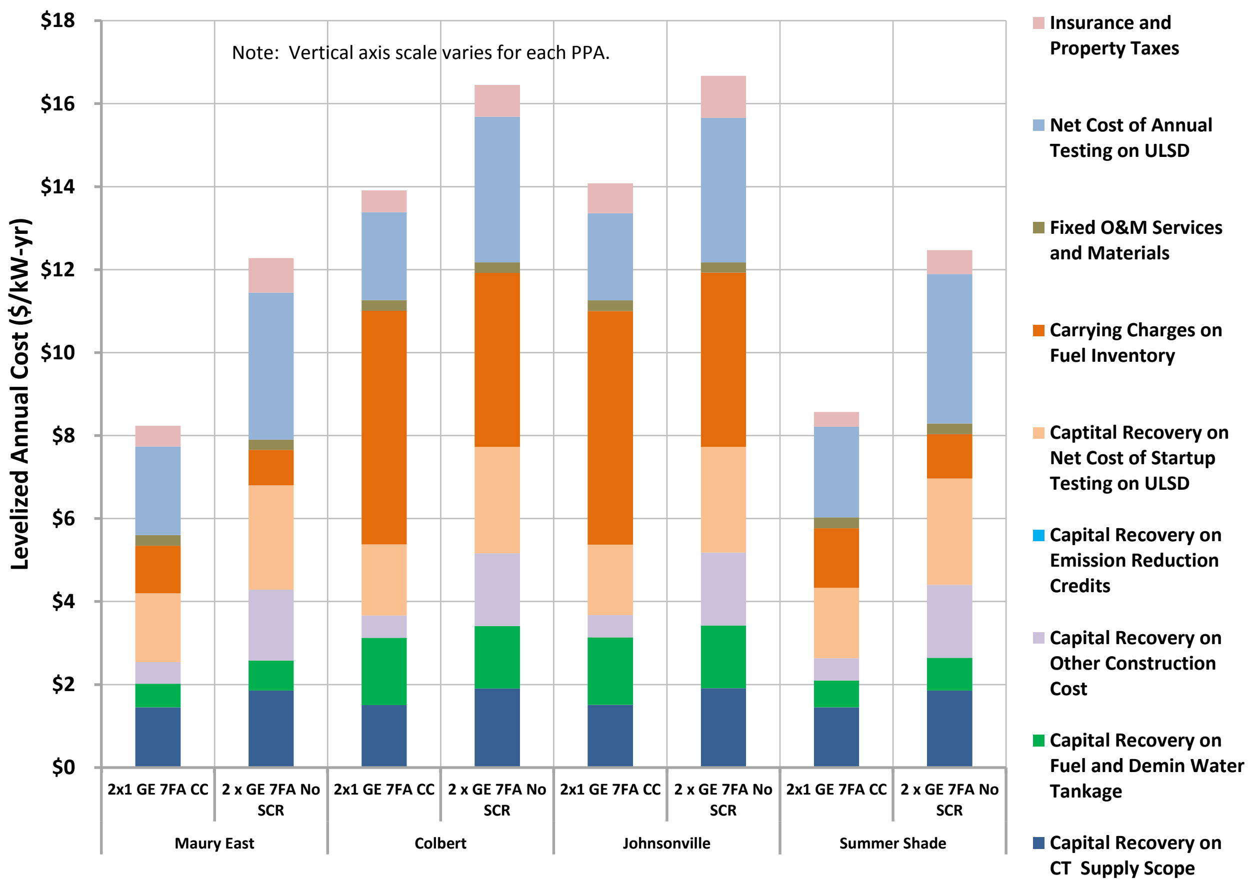

Figure 11-22. Dual-Fuel Cost Details for TVA Locations

11.6.8.1.6 IESO Locations

Figure 11-23 shows the components of dual-fuel capability cost for the locations selected by IESO. Both of these locations assume truck delivery of ULSD and use 2x7FA as the SC generation technology.

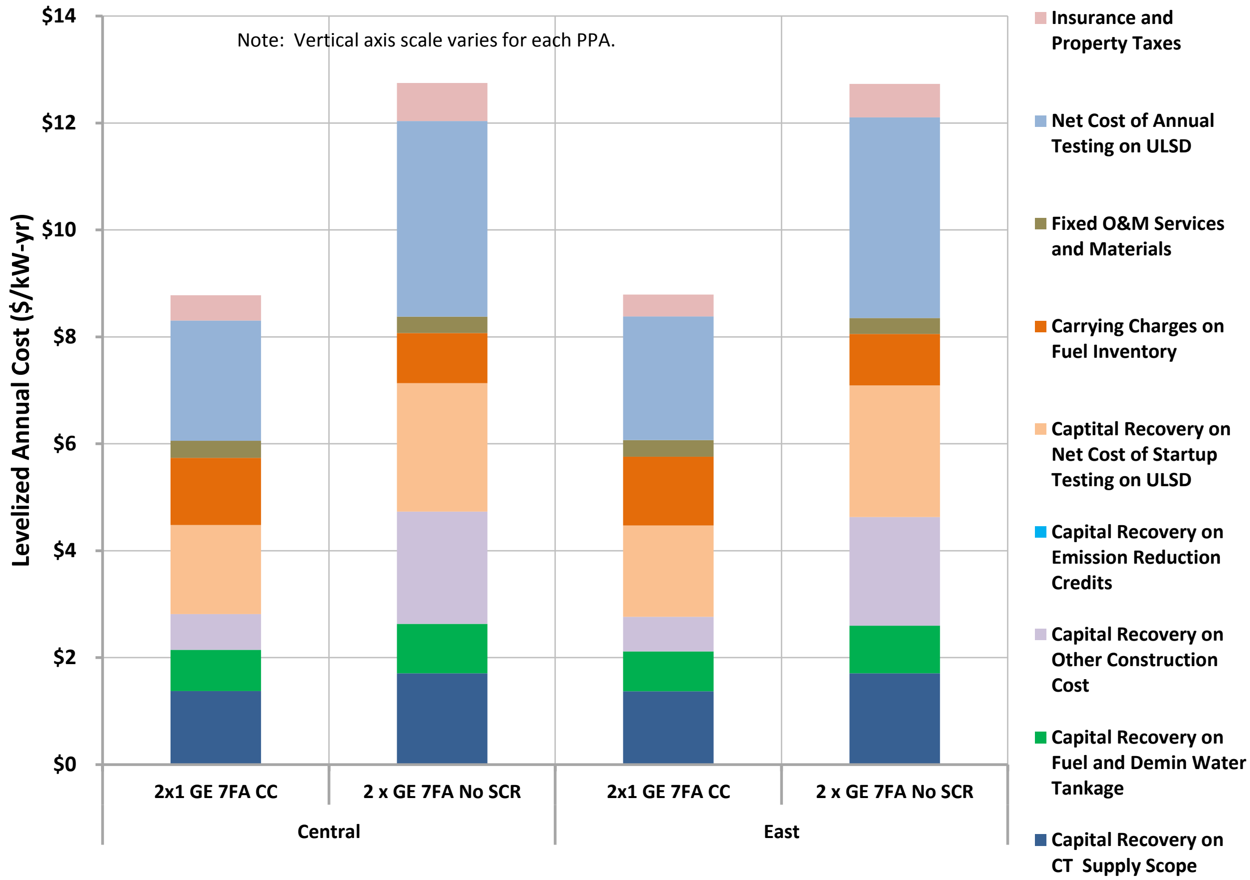

Figure 11-23. Dual-Fuel Cost Details for IESO Locations

11.6.8.2 Levelized Net Cost of FT Service

The net FT costs expressed as $/mo per Dth/day described in Section 11.6.3.3 and depicted in Figure 11-4 were converted to levelized annual costs in $/kW-day for each location for both CC and SC plants using the corresponding winter full load ULSD firing rates and summer installed capacities. Escalation on the 2018 rates was assumed to be at 2% per year, and discounting was applied at the WACC determined for each location. The costs for CC plants vary from $2.67/kW-yr at the MISO Upper Peninsula location to $105.51/kW-yr at the NYISO Long Island location. Levelized costs for SC plants are substantially higher. The results of this calculation are shown in the following section.

11.6.8.3 Comparison of Dual-Fuel Capability and FT Service Levelized Costs

A comparison of the levelized costs for the two fuel assurance strategies for CC plants at each of the 27 locations is provided in Figure 11-24. A similar comparison for SC plants is provided in Figure 11-25. For both plant types, FT service is substantially more expensive in New England and downstate New York than in any of the other areas. For CC plants, the costs of dual-fuel capability and FT service are similar at the NYISO Capital District location, all MISO locations, several PJM locations, and three of the TVA locations. For SC plants, the levelized annual cost for FT service is higher than that of dual-fuel capability for all locations.

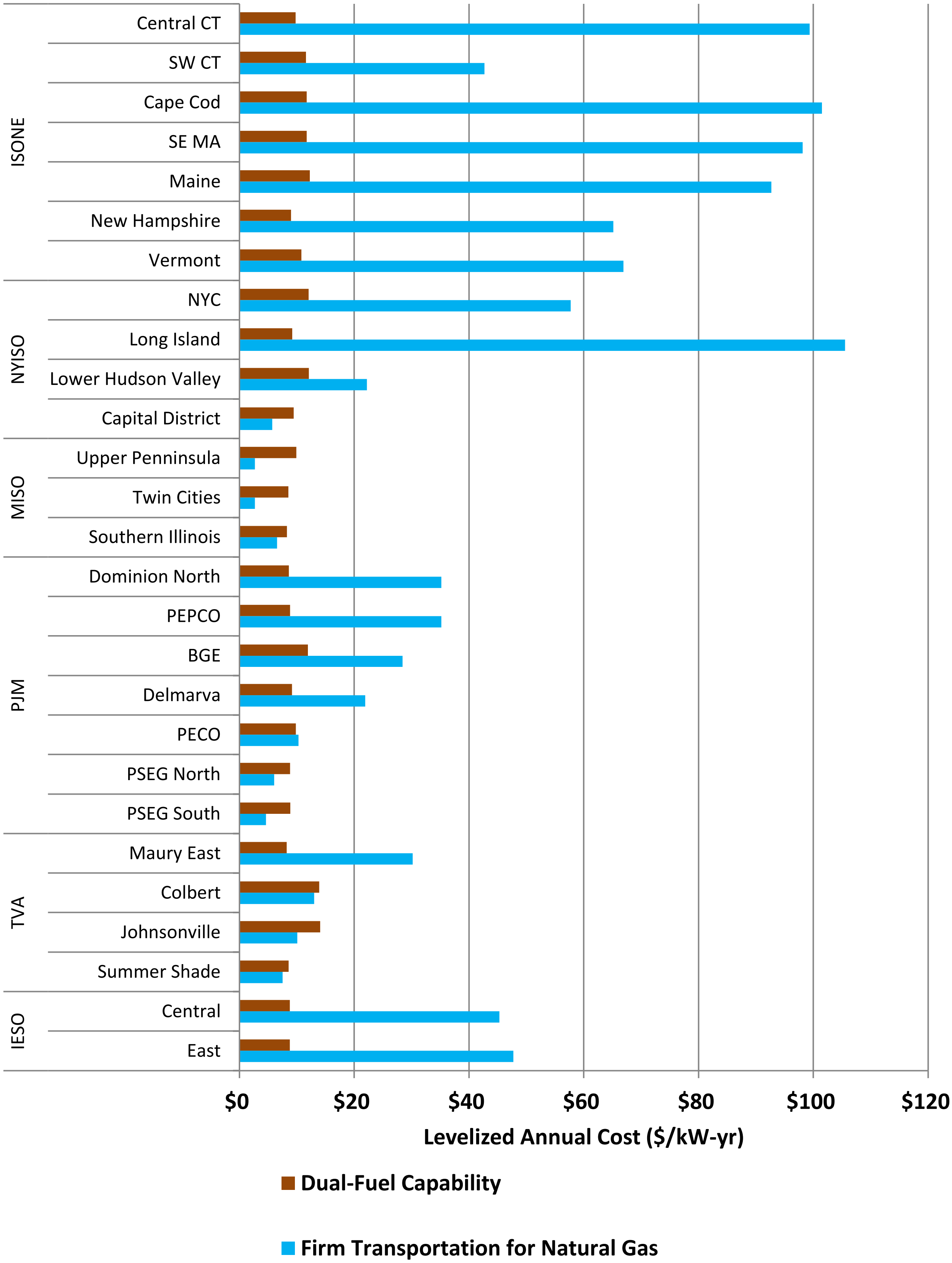

Figure 11-24. Comparison of Fuel Assurance Strategies for Combined Cycle Plants

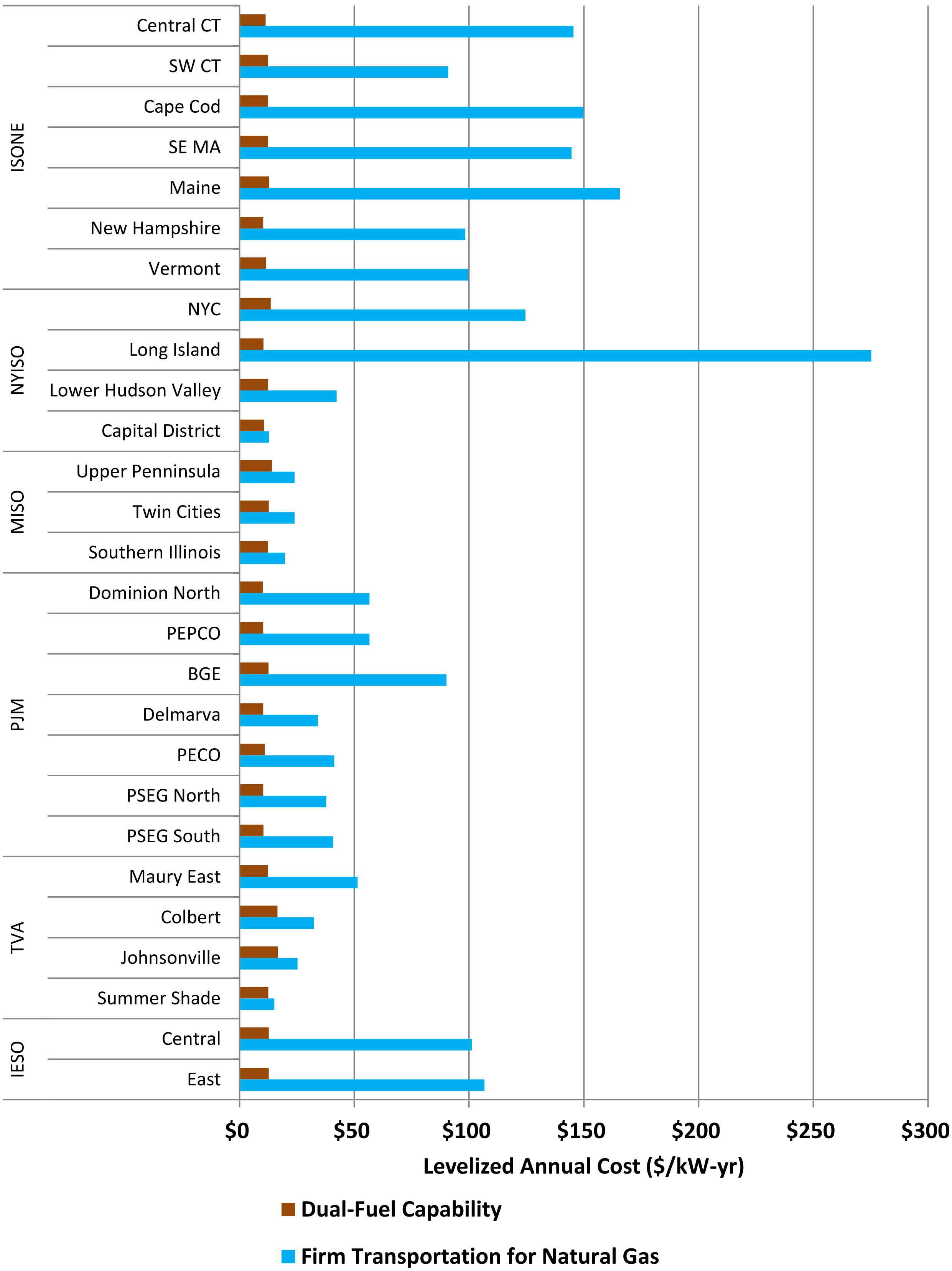

Figure 11-25. Comparison of Fuel Assurance Strategies for Simple Cycle Plants

In reviewing the financial results associated with the relative cost of dual-fuel capability versus FT, a number of general observations follow with respect to the economic tradeoffs for a combined cycle plant.

- First, in ISO-NE the high cost of firm transportation as well as the cost of improvements on laterals from mainline facilities to the plant gate cause FT to be much more expensive than dual-fuel capability to meet the fuel assurance objectives.

- Second, in NYISO the high cost of laterals to firm up local transportation explains the large divergence between FT and dual-fuel capability in New York City and Long Island. The cost differential is much smaller in the Lower Hudson Valley and the Capital District.

- Third, in MISO the cost of FT is much lower than neighboring PPAs, rendering FT a viable alternative to dual-fuel capability to satisfy the fuel assurance objective. The cost differential between competing strategies is comparatively small, however.

- Fourth, in PJM there are several locations where the cost of FT is somewhat lower or approximately the same as dual-fuel capability. The cost of dual-fuel capability in BGE appears higher than other PJM locations because of the higher cost of barge deliveries and tankage assumed in the Inner Harbor, an area with good access to barge transported supply with anticipated permitting restrictions affecting the ability of many trucks to refill oil tanks during the peak heating season.

- Fifth, in TVA the cost of one strategy versus the other is more or less the same, except at Maury East where the incremental cost of FT is much higher than dual-fuel capability.

- Sixth, in IESO the cost of dual-fuel capability is significantly lower than incremental FT on TransCanada and either Union or Enbridge.

11.6.9 Conclusions

The cost of fuel assurance through dual-fuel capability is relatively constant over a wide range of locations. This is because the cost of dual-fuel capability is driven by common incremental plant scope elements and the commodity cost of ULSD for testing and inventory. Locational differences in labor costs, taxes, and target inventory levels result in a range in levelized costs from about $8/kW-year to $14/kW-year for the combined cycle technology option. Costs are slightly higher for simple cycle plants due to higher heat rates.

Conversely, the cost of fuel assurance through FT is driven by the costs of incremental pipeline capacity. These vary broadly by constrained location, particularly in the Northeast. They can vary significantly from one delivery path to another. Laterals required to provide fuel assurance at locations otherwise served by LDCs via non-firm transportation arrangements at the local level add additional costs to the supply chain that would need to be firmed up at the local level in order to assure deliverability from the producing basin to the plant gate.

With few exceptions, dual-fuel capability appears to be much less costly with respect to reducing the direct cost strategy to achieve fuel assurance. The primary reasons supporting these results are five-fold: (i) existing pipelines in constrained locations are typically fully subscribed, thereby requiring a pipeline to add expensive new facilities to firmly serve a gas-fired generation plant; (ii) generators behind LDC gate stations would be expected to bear the high cost of local facility improvements to ensure year-round service *in addition to* mainline improvements from the producing basin to the local system either through new expansion projects or by arranging for expansion capacity contracted by a producer or other third-party; (iii) the avoided cost of non-firm transportation is not sufficiently high in most constrained locations to significantly reduce the net cost of incremental firm transportation service; (iv) the capital charges, inventory carrying charges and incremental fixed O&M associated with dual-fuel capability are comparatively low; and (v) structural change in the distillate oil market has and will continue to simplify the logistics of ULSD replenishment during cold snaps or other outages or contingencies.

The extensive use of ULSD as a back-up fuel for SC and CC plants will be impacted by more than the improved availability of ULSD. Emissions requirements can limit the total number of hours for which a plant can burn ULSD during any 12-month period. Local zoning regulations can impact the size of on-site storage tanks and the frequency of truck deliveries to provide ULSD replenishment. In most cases the emissions controls on new plants as well as the sizing of on-site ULSD storage and unloading facilities along with careful consideration of resupply logistics and scheduling can adequately address these issues.

These results provide the PPAs with valuable information about relative cost tradeoffs associated with satisfying the fuel assurance objective. The results do not incorporate sundry commercial considerations which may otherwise induce generators to invest in firm transportation, for example, different operating characteristics, enhanced profitability from energy sales, margin recoupment from the redeployment of firm capacity rights, and the ability to source gas at a lower price and more stable trading point under FT service. The impact of these commercial considerations is not strictly tied to the reliability-based analysis that is the basis for this report and as a result has not been investigated in the Target 4 study.