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Informal Report

**LIQUID NATURAL GAS (LNG):
An Alternative Fuel From Landfill Gas (LFG) and
Wastewater Digester Gas**

by
David Vandor

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Prepared for: **Brookhaven National Laboratory***
Brookhaven Science Associates
P.O. Box 5000
Upton, NY 11973-5000

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Prepared by: **V A N D O R + V A N D O R**
ALTERNATIVE ENERGY SOLUTIONS
26 Leroy Avenue, Tarrytown, NY 10591
Telephone (914) 631 6442; Telefax (914) 332 7176

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1.0 EXECUTIVE SUMMARY

This "Research and Development Subcontract" sought to find economic, technical and policy links between methane recovery at landfill and wastewater treatment sites in New York and Maryland, and ways to use that methane as an "alternative fuel" -- compressed natural gas (CNG) or liquid natural gas (LNG) -- in centrally fueled Alternative Fueled Vehicles (AFVs).

In §2.0, we outline the study's scope as well as some basic assumptions regarding centrally fueled AFV fleets, including the need to focus on heavy-duty fleets (trucks and buses) in lieu of light-duty vehicles. Section 2.0 also describes Landfill Gas (LFG), wastewater digester gas and LNG, and the pollution prevention goals of LFG reclamation.

Section 3.0 reviews some existing LFG gas recovery projects. The Fresh Kills landfill on Staten Island is currently producing pipeline quality gas that is inserted into the local gas distribution network. Yet, no particular effort is being made to direct that gas to New York City's AFV fleets.

Section 4.0 analyzes landfills in New York and Maryland as well as wastewater treatment sites in New York City. The technical issues associated with the gathering of landfill gas and its clean-up to pipeline quality has been solved for large landfills. However, we did not find a single existing landfill site that produces LNG and none that had a significant link to a large CNG dispensing network.

We also did not find any wastewater treatment plants that produce pipeline quality methane from digester gas. None of the LFG clean-up systems now in operation have been "scaled down" to the lower gas-flow rates of wastewater treatment plants.

Section 5.0 reports on several LFG clean-up processes. The Kryosol Process seems to show the most promise. It is now in use at a landfill in Pennsylvania and will be in operation at two other sites, one in Ohio and one in Michigan, before the end of 1999. The Kryosol Process has a "track record" and it can operate economically at sites with LFG production rates of only 1.0-billion cubic feet per year.

The total cost of a Kryosol Process plant, including for a "food grade" CO₂ production unit, is approximately \$6,000,000, not including on-site gas gathering systems. Based on the value of the cleaned-up gas and the CO₂, the return on investment for a private entity (but especially for a non-taxed public entity) looks to be enough to produce a positive income stream well within the productive life of a landfill.

In §6.0, we report on small scale LNG "liquefaction plants" that might economically produce LNG at existing landfills. As of mid-February, 1999, there were no small scale liquefaction plants on the market that have demonstrated their capacity to liquefy pipeline quality gas efficiently. More importantly, only the CryoFuel System claims to be targeting none-pipeline quality gas. The other systems seem to require extensive pre-cleaning systems to dry and clean the LFG prior to liquefaction.

In §7.0 we identify alternatives for establishing links between urban AFV fleets and remote landfill sites. We recommend that existing, highly efficient and amortized LNG peak shaving plants be relied on for the production of LNG and that the cleaned landfill gas be "wheeled" to the plant to reduce commodity and transportation costs.

This model will also work in urban areas that rely on CNG and do not have nearby LNG sources. In contexts where a large enough LNG market can be established, a newly constructed "let-down-cycle" LNG plants may be worth considering. In other contexts, the upgrading of existing gas processing plants, to also produce LNG, may be worth exploring. The capturing of "free" energy at "let-down-cycle" gate stations is a demonstrated process that can be applied to CNG dispensers as well, significantly reducing their operating cost.

Eastern-Maryland does not contain gas pipeline networks that allow for "wheeling" of cleaned landfill gas. In such contexts small scale liquefiers, such as the CryoFuel System, may be the only option for using cleaned LFG. If the CryoFuel system proves to be cost-effective at a landfill, it can then be tested at a wastewater treatment plant.

Section 8.0 reviews the impediments and opportunities associated with establishing a "vertically integrated" LFG -to-CNG/LNG network. The most significant impediment in New York is the existing LNG moratorium. If the moratorium is renewed, the opportunities for the economic development of LFG as an AFV fuel in New York will be limited to areas with local CNG networks.

New York's other impediments include a lack of existing LNG infrastructure, with only one LNG plant in the entire state that is not within the jurisdiction of the New York City Fire Department. New York also has some of the highest taxes on alternative fuels in the country. While this is not an issue for public AFV fleets, it serves as a strong disincentive for the private sector.

The opportunities in New York include two very large landfill sites, one of which (Fresh Kills) is now producing pipeline quality gas. Other opportunities include a significant number of large publicly owned landfills that have enough LFG generating capacity to justify the construction of clean-up technologies, as well as several large wastewater treatment plants, a significant number of AFVs, and an existing AFV tax credit program that could encourage private sector AFVs and the dispensers to fuel them.

Maryland's impediments include the absence of a comprehensive plan to encourage public or private AFV fleets, and no apparent history of LFG reclamation and clean-up.

The opportunities in Maryland include a centrally located LNG plant that has excess capacity and the ability to transport the product off-site. Maryland has several landfills with enough LFG generating potential to justify the construction of gas clean-up systems. The state's lack of pipelines along its eastern shore offers an opportunity to produce and ship LNG (to non-pipeline areas) from "wheeled" gas derived from landfills near pipelines. Maryland's greenhouse industry may be a market for liquid carbon dioxide, a byproduct of cleaned LFG.

Section 9 reviews financial and tax issues. Federal and state policies do not encourage, through tax incentives, the pollution prevention benefits of cleaning LFG and using it as a fuel in AFVs. New York's existing tax incentive apply only to AFVs and alternative fuel dispensers. No incentives are available for the production or use of alternative fuels and there are no incentives for reducing LFG emissions or for cleaning LFG. Maryland's incentives for AFVs are insignificant.

In §10, the report concludes that the lack of examples for linking LFG and wastewater digester gas reclamation to AFVs is not due to technical obstacles, but rather to the lack of a comprehensive "chain" that links landfills and wastewater treatment plants to municipal AFVs -- **LFG-to-clean-gas-to-CNG/LNG-dispensing**.

The technology for each link exists. LFG gathering systems are routine; competing clean-up technologies are commercially available; pipelines that move clean methane from landfills to urban distribution networks are in place and (in several locations) are connected to the clean-up systems at landfill site; CNG dispensers, LNG peak shaving plants and large gas processing plants are located on these pipelines; and centrally fueled AFVs, public and private, are operating within the local areas served by these networks.

Only landfill sites that produce more than 1-billion cubic feet of LFG per year should be considered for LFG-CNG/LNG programs. New York's and Maryland's top half-dozen landfill sites fit within this screen.

Given the richness of wastewater treatment digester gas, the long life of treatment plants, the steady and predictable flow rate and several other benefits, plants that produce only 500,000,000 cubic feet of digester gas may prove to be a productive long-term source of clean fuel. Because the largest wastewater treatment plants are located in New York, we suggest that any further analysis of the technical and economic issues associated with digester gas be examined first in New York City.

Because government agencies operate outside of the state and federal tax structure, municipal landfill and wastewater treatment plants should first be "linked" to municipal AFV fleets. A municipal landfill can value its LFG at virtually zero and can dispense CNG/LNG to the public truck or bus fleet without the burden of taxes. New York's public entities may rely on Environmental Bond Act funds to offset the cost of AFVs.

In §11 of the report we suggest follow-up work that will advance a comprehensive approach for a vertically integrated LFG-to-CNG/LNG network, starting with public landfills and wastewater treatment plants feeding CNG/LNG to public fleets. The broad scope of this study should be narrowed down, in follow-up efforts, to the evaluation of specific technologies applied to specific sites. Our goal is to move from general data gathering and analysis, to localized studies, followed by the application of appropriate "hardware" that fits within a comprehensive, vertically integrated LFG-to-AFV plan.

2.0 BACKGROUND

2.1 Study Scope

This "Research and Development Subcontract" was undertaken to study the potential use of methane (natural gas) as an "alternative fuel" where the source methane is captured at landfills and wastewater treatment plants and where it is cleaned and liquefied into Liquid Natural Gas (LNG) and used as a vehicle fuel, on- or off-site.

The study focused primarily on landfill sites, and secondarily on wastewater treatment plants. Some aspects of this report are generic and have applicability throughout the United States. However, the study was limited to sites and issues within the states of New York and Maryland.

The study's purpose was not to develop new techniques for recovering, cleaning or liquefying landfill or sewage treatment gas, but rather to report on existing techniques and policies, and on opportunities and constraints that allow the expansion of pollution prevention in two contexts: 1) at waste gas producing sites, such as landfill sites and wastewater treatment plants, and 2) within the geographic limits of the daily travel routes of centrally fueled vehicle fleets.

The following were the objectives of this Research and Development Subcontract:

1. Prepare a list of potential methane producing **landfill and wastewater treatment sites**. See §4.0.
2. Identify gas **reclamation methodologies** and entities. See §4.3.
3. Identify gas **"cleaning" systems** and entities that can produce "pipeline quality" gas from methane produced at landfill sites and sewage treatment plants. See §5.0.
4. Identify **liquefaction technologies** and entities. See §6.0.
5. Identify technical and/or economic **impediments/opportunities** related to the production of LNG from landfill sites and sewage treatment plants. See §7.0 and §8.0.
6. Identify existing **financing programs and/or tax incentives** related to the "clean-up," gas reclamation, and/or energy production at landfill sites and sewage treatment plants by the federal government or by the state governments of New York and Maryland. See §9.0.
7. Suggest **follow-up studies** (if warranted) to resolve technical, economic and political obstacles/opportunities related to the cost-effective production of LNG, from methane produced at land fill sites and sewage treatment plants. See §11.0.

2.2 General Assumptions

This study is based on a core assumption that pollution prevention must be done in a comprehensive way. Public policy links need to be found between gas processing at landfill and wastewater treatment sites and the off-site use of cleaned methane as a

vehicle fuel to be used in lieu of diesel and gasoline. In addition, the Alternative Fuel Vehicle (AFV) industry's best experience needs to be part of a comprehensive plan, as per the following:

- Centrally fueled fleets, with high daily fuel consumption, operating in dense urban areas, are ideal candidates for replacement with AFVs. Taxis, municipal and private bus fleets (including school buses), airport service vehicles, and urban delivery trucks are ideal AFV candidates.
- Fleets that are subject to state and federal mandates to increase their percentage of AFVs are also ideal.
- CNG/LNG dispensing stations reach their optimum economic value when they operate at or near their dispensing capacity. For that reason, a critical mass of AFVs need to be committed to a single dispenser, which must be sized appropriately for the existing demand and must have the capacity to allow for growth.
- Economics of scale affects all levels of the AFV dispensing model.
- The cost of the dispensed fuel, fully taxed when sold to private sector entities, or un-taxed when sold to public sector and not-for-profit fleets, needs to be less than the "equivalent" cost of the replaced fuel. "Equivalence" needs to be measured not by volume or "heat content" (BTU), but on a mile-traveled basis. For example, if 125 scf of CNG is deemed to be equivalent to a gallon of gasoline, we need to confirm that the CNG powered AFV will travel the same distance (say 15 miles per gallon) as it would on gasoline. Similarly, if 139 scf of CNG is deemed to be equal to a gallon of diesel, then a truck that normally travels 7 miles per gallon of diesel must achieve 7 miles per 139 scf of CNG. Otherwise, the "diesel equivalent" 139 scf is not truly equal to a gallon of diesel. The industry standard of 1.7 LNG gallons equals one gallon of diesel has not been demonstrated to be accurate in urban applications involving stop-and-go driving.
- The incremental extra cost of AFVs needs to be accounted for in the lifetime operating cost of the AFV. For private sector fleets, local tax credits (such as those available in New York State), may offset the vehicle's extra cost. If the fuel cost and other operating costs are lower, they can also offset the AFV's total cost over the life of the vehicle. If the fuel costs are not lower for the AFV then the incentives offered need to be even larger than the incremental extra cost of the AFV in order to offset the annual increase in the AFV's operating costs. Such incentives may include preferred parking at "green curbs," registration and toll discounts, and the "sponsorship" of AFVs.
- Most existing AFV mandates focus on light-duty vehicles. However, heavy-duty vehicles tend to be less fuel efficient than light-duty vehicles, and tend to use diesel, which is not as clean as the gasoline. Public policies should focus more on heavy-duty vehicles as candidates for AFV replacement. To the extent that municipalities control landfill sites and wastewater treatment plants, the distribution of cleaned landfill or wastewater digester gas should first be targeted at heavy-duty public AFV fleets, followed by private sector heavy-duty fleets, followed by light-duty public fleets.

- Replacing light-duty gasoline vehicles with CNG powered cars will not achieve as much pollution prevention or energy independence as replacing heavy-duty diesel buses or trash haulers with LNG powered equipment.
- On-board CNG tanks can take up a significant amount of space in small vehicles, relative to the size of the vehicle and in comparison to the standard gasoline tank. Thus, the daily range of CNG powered vehicles is limited, unless the tanks are mounted on the roof, as in the New York City CNG bus fleet. For private sector trucks and other "weight-sensitive" fleets, the option of mounting a large number of CNG tanks on the roof, or under the chassis is not as attractive as using LNG. Fifty-five gallons of diesel can fit within a 551 pound "package," including tank and fuel weight. The "equivalent amount of CNG would require 2,535 lbs of fuel and tanks. In one configuration, the 11 required CNG cylinders would each measure approximately 13.5" by 72", as compared to a single diesel tank which measures 20" by 50". The equivalent LNG tank and fuel weight is 639 lbs. and measures approximately 25" by 63", which is very similar to the diesel tank's size.
- A major benefit of CNG/LNG production that is linked to landfill gas or wastewater digester gas upgrading is the degree of "energy independence" achieved by the municipal entity.
- Landfill sites are "renewable" energy sources, but only within the limited gas-producing life span of each landfill. Wastewater treatment plants, on the other hand, are permanently renewable.
- A comprehensive approach to LFG reclamation will include new uses for liquid carbon dioxide (CO₂), a by-product of the LFG and wastewater digester gas clean-up process.

2.3 What is Landfill Gas?

Landfill gas is produced through the biological decomposition of organic waste mater. The process is "natural" and includes a short period of aerobic decomposition (with oxygen) and a longer period of anaerobic decomposition (without oxygen). The resultant gas may have a variety of chemical components, but at most public and private municipal solid waste disposal sites the principal components are methane, carbon dioxide, water vapor and lesser amounts of hydrogen sulfide, and nitrogen. The composition of landfill gas will vary from site to site and will vary at each site over the gas-producing life of the landfill.

Typically, landfill gas contains from 45% to 55% methane, 40% to 55% carbon dioxide and up to 4% inerts and 1% hydrogen sulfides and volatile organic compounds (VOCs). In a 1980 study by Gas Recovery Systems Inc., titled "Analysis of Methane Potential at New York State Sanitary Landfill Sites," prepared for the New York State Energy Office, the formation of landfill gas is characterized as a "four phase" process. The report offers the following analysis of the final phase of the waste decomposition process:

The fourth phase differs from the third in that gas production and composition approach steady state conditions. The percentage of methane in the gas may range from 50 to 70 percent; carbon dioxide from 30 to 50 percent.

In short, the main components of landfill gas are methane, carbon dioxide and water. If untreated, landfills are a source of methane emissions, a potent greenhouse gas, and if allowed to escape, a wasted resource. Other undesirable emissions can include non-methane organic compounds, chlorinated and fluorinated compounds, and particulates.

More detail on LFG composition can be found in the other sections of this report. For example in the sections that report on the Acrion and Kryos LFG-cleaning technologies, the report lists each company's experience with regard to compounds that, even in small quantities, require some treatment.

2.4 What is Wastewater Treatment Digester Gas?

Wastewater treatment digester gas results from the anaerobic (without oxygen) decomposition of municipal sewage. Similar to LFG, it contains mostly methane and carbon dioxide. However, digester gas tends to have a higher concentration of methane (64% at New York's Yonkers plant) than typical LFG which may contain 50% to 55% methane. Digester gas is "richer" than LFG. However the largest NYC wastewater digester gas rate flow is significantly less than the LFG flow rate at any operating landfill site. (For more on this issue, see §4.6.)

The chemical composition of digester gas, in addition to its higher methane content, differs from LFG in that it may contain more sulfur compounds than typically found in LFG. In short, cleaning of digester gas will require modified LFG cleaning techniques.

The challenge is to produce a cost effective clean-up system designed for the chemical composition of the typical digester gas flow, and to design that system in a modular manner that can be replicated at a number of wastewater treatment sites. In an optimistic scenario, the "richness" of the digester gas flow and the long life of the treatment plant (as compared to the limited gas-producing life of a landfill), will offset the reduced volume of gas. (Please see §4.6.)

2.5 What is LNG?

LNG is a clear and colorless liquid form of natural gas. To reach and maintain a liquid state the natural gas is chilled (and insulated) to approximately minus-260 degrees Fahrenheit. LNG weighs about half as much as the same volume of water. The main benefit of LNG is that it takes up significantly less volume than standard natural gas. Compressed Natural Gas (CNG) produced from the same pipeline gas (including gas for domestic use in stoves and hot-water heaters) takes up more than 600 times as much volume as the equivalent amount of LNG.

Diesel fuel is the dominant transportation fuel used in heavy-duty trucks, buses, locomotives and urban ferries, as well as in "off-road" heavy equipment such as those used at landfill sites. Diesel has been linked to urban air pollution and is considered a significant source of emissions in "non-attainment areas." Diesel exhaust, especially particulate matter, has been linked to cancer in those who live and work near concentrated sources of diesel emissions.

By contrast, Liquid Natural Gas (LNG) has been identified as an "alternative fuel" that is significantly cleaner than diesel, is technically appropriate for use in heavy-duty vehicles and unlike diesel is generally produced from domestic sources of natural gas. LNG has excellent potential to compete with diesel, at least in terms of the volume of fuel that can be carried on-board a vehicle, relative to the fuel economy of the engine and the required range of the vehicle.

Pipeline gas as a source of LNG, is readily available in New York and Maryland. However, such gas is generally "transported" (through a national pipeline network) long distances from its source in the south-west and then needs to be liquefied in local liquefaction plants. Most such existing facilities were built as "peak shaving" plants.

New York has three such plants, in Brooklyn, Queens and on Long Island. All were built prior to the existing LNG moratorium in NY. Maryland has two plants. Delmarva Power's Wilmington, Delaware LNG plant is also close to Maryland.

Peak shaving plants act as "insurance policies" against the need to purchase large quantities of pipeline gas during the winter when the price of the commodity is more expensive than the same volume of gas purchased in the summer. An LNG peak shaving plant and its on-site storage containers allow the local utility to buy gas during low demand periods and to store it (in liquid form) for high demand periods.

Pipeline-source LNG's final price reflects the feed-stock's commodity price, its pipeline transportation cost, its liquefaction and storage costs, and finally its transportation cost to a dispensing site at or near a customer, such as a fleet of AFVs. While the cost/benefits of liquefying LNG from pipeline gas is not the scope of this Research and Development Subcontract, we can predict that in most local contexts the cost of pipeline based LNG, as a substitute for diesel, tends to be more expensive (on a per-mile-traveled basis) than the cost of diesel. Therefore, this Research and Development Subcontract seeks to identify the potential for utilizing methane from landfills and sewage treatment plants as an alternative to pipeline-source LNG.

2.6 Pollution Prevention

"Pollution prevention" at landfill sites has become an important local, regional and national policy. The President's 1993 US Climate Change Action Plan sought ways to reduce US Greenhouse Gas emissions to 1990 levels by the year 2000. With regard to landfill sites, the plan called for more stringent EPA emission regulations, the creation of EPA's Landfill Methane Outreach Program, and increased research and development efforts concerning the recovery of methane from landfills.

In EPA's report titled "Emerging Technologies for the Management and Utilization of Landfill Gas," (EPA-600/R-98-021), published in February of 1998, the following is written regarding landfill emissions:

The EPA finalized regulations for new landfills, and guidelines for existing landfills, to reduce emissions on March 12, 1996 (61 FR 49, 1996). However, the regulations do not require the utilization of LFG [landfill gas] to produce energy or other products.

2.7 Landfill Gas Utilization

The EPA report goes on to state that "of the landfills expected to be constructed over the next 5 years, about 45 are estimated to require LFG collection and control systems," and "for existing landfills with capacities greater than 2.5 million megagrams, approximately 300 will be required to install collection and control systems."

Of 121 landfill sites that are known to EPA as utilizing LFG, 89 produce electricity with reciprocating engines, 22 produce electricity with gas turbines, 5 produce electricity with boiler/steam turbines, and only 5 produce "high BTU gas" that is suitable for use as a vehicle fuel. Of these no more than two or three sites produce pipeline quality gas for insertion into adjacent natural gas pipelines. In the New York and Maryland context of this study, we have identified only New York's Fresh Kills Landfill on Staten Island as producing/inserting pipeline quality gas.

We believe that no landfill site in the United States that produces vehicle-quality natural gas takes the extra step of liquefying the gas into LNG. There are a number of reasons for this, including the following:

- Historically, LNG plants tended not to be economical unless they were very large.
- The extra cost of producing LNG is not warranted when the AFV is a light duty vehicle, when only a few vehicles rely on the vehicle-quality gas, when the program is experimental and is run merely to "demonstrate" the quality of the gas, when the issue of vehicle range, (or fuel tank size and weight) such as for an on-site vehicle, is not a concern, and in contexts where there is no plan to move the fuel off-site in any significant quantities.
- Local AFV policies are often independent of pollution prevention policies at landfill sites, the possible links between a municipality's assets at landfills and the fueling of AFV fleet is rarely made. LNG can offer more flexibility than CNG in fueling off-site vehicles. But if there is no policy to link landfills to AFV fleets, there is no need to produce LNG at the landfill.

3.0 LFG TO VEHICLE FUEL

3.1 CNG Production at Puente Hills, Los Angeles, CA

LFG recovery at the Puente Hills Landfill site in Los Angeles California is described in some detail in EPA's "Emerging Technologies..." report. Puente Hills produces about **27,000** standard cubic feet per minute (scf/m) of LFG. About **23,500** scf is used in boilers and turbines to produce electricity. Another **200** standard cubic feet is sent, off-site, to a college for use as boiler fuel. The remaining **3,300** scf is used to produce vehicular grade CNG, or more specifically compressed landfill gas, or CLG. The site has a "design capacity of 1,000 gallons of gasoline-equivalent CLG per day." A gasoline equivalent gallon (GGE) is assumed to be 125 scf of CNG/CLG. EPA reports that "as of 1996, the (CLG) demand has been over 800" GGE per day.

The capital costs for the CLG portion of the gas recovery project was approximately \$1,000,000 in 1992. The "fuel cost" of Puente Hill's CLG, at the maximum (100%) production rate, is \$0.48 per GGE. This figure includes "capital recovery" over 15 years, at a 7% interest rate, and assumes that power to run the system cost 5¢ per kWh.

In the Puente Hills context, a 2,000 GGE production facility "could be economically competitive when CNG is sold at \$0.70/GGE. In the New York context of 1998, fully taxed CNG is available at what is purported to be the same price as a gallon of gasoline, say \$1.00 per GGE. Thus, if a New York based landfill site could economically produce CLG (but not LNG, which requires further processing) at a price that is less than \$0.50/GGE, it might be competitive.

However, as a substitute for diesel fuel in medium- and heavy-duty trucks and buses, the price of CNG needs to be lower to account for the loss of efficiency of the CNG engines. Most CNG engines produced by original equipment manufacturers (OEM) will not provide the same mileage per diesel equivalent gallon (DEG) using CNG as diesel will. For a truck that normally attains 7 miles per diesel gallon, its CNG counterpart will not likely achieve more than 5.95 miles per DEG (139 scf of CNG) -- only 85% of the diesel vehicle's range.

3.2 CNG at Wisconsin Rapids, WI & Westchester, NY

EPA reports that the Tork Landfill, in Wisconsin Rapids, WI, used a skid mounted "prototype" that converted LFG to CLG/CNG in two steps. The gas was first cleaned of moisture and non-methane organic compounds in a patented process. The second step separated carbon dioxide from the methane by mixing the gas with "Selexol," a brand name poly-glycol solvent. The carbon dioxide seems to have been "discharged to the ambient air" rather than collected as a "commodity."

The capital costs of the Tork "prototype" was \$400,000 in 1992. It is not clear what the equipment's daily CNG production capacity was, but we can assume that it was small.

Subsequently, the system was moved to the **Croton Landfill** in Westchester County, NY. EPA reports that the re-located system produced CLG that was 85% to 95%

methane and thus suitable for vehicular use. (It should be noted that "pipeline quality" methane is 98% pure!) The equipment is "currently processing 20,000 scf/d of raw LFG" which contains 50% methane. This is a small portion of the 1,000,000 scf/d of LFG produced at the Croton Landfill. To the best of our knowledge the Croton facility is no longer producing CLG. We assume that such a small system could not be operated economically. It is also important to note that if less-than-pipeline-quality gas is used in vehicles, a long term maintenance record for those vehicles is essential.

No operating costs are provided for the Tork or Croton systems in EPA's report. The report is also silent on how much of the 20,000 scf/d of raw LFG is used as an energy source in operating the equipment. However, the report does suggest that the economic viability of a larger CNG production facility may well hinge on the demand side of the equation. Who will purchase large quantities of CNG, and at what price?

3.3 Fresh Kills Landfill, Staten Island, NY

The Fresh Kills landfill's gas processing system is operated by GSF Energy, Inc., an operating division of Ecogas, based in Austin Texas. Mr. Scott Hill of Ecogas (Tel. 512-347-1441) is listed as an EPA Landfill Methane Outreach Program "Industry Ally."

In addition to the Fresh Kills site, Ecogas operates several other LFG-to-energy sites, including the following that produce pipeline quality methane:

- McCarty Road in Houston Texas, operated by Browning-Ferris, Inc. and International Disposal Corporation, has **14 million** tons of landfill in place. The **269 acre** site has **9.0 million** cubic feet per day LFG processing capacity. A high BTU plant supplies pipeline quality gas to the Enron Corporation, at a capacity of **4.5 million** cubic feet per day. Pretreatment of the LFG includes "iron sponge" hydrogen sulfide removal a liquid absorption process for non-methane hydrocarbon and CO₂ removal.
- The Rumpke site in Cincinnati, Ohio, has **11.5 million** tons of landfill in place. Of the site's 600 acres, **128 acres** are filled. The site's LFG processing capacity is **9.0 million** cubic feet per day. A high BTU plant supplies pipeline quality gas to the Cincinnati Gas & Electric Company, at a capacity of **4.5 million** cubic feet per day. Pretreatment of the LFG includes non-methane hydrocarbon removal by a chilling and activated carbon absorption process.

In a recent telephone interview Mr. Scott confirmed that the GSF LFG pipeline-quality processing system favors large landfills that produce over 8,000,000 cubic feet of LFG per day. EPA estimates that the total LFG potential of Fresh Kills is 16,602,500,000 cubic feet per year, or 45,486,301 cubic feet per day. Thus, Fresh Kills is an ideal site for the Ecogas / GSF process.

However, the next largest landfill site(s) in New York (and the largest landfill sites in Maryland) have an LFG production potential of no more than 4.0 million cubic feet per day. Thus, the current GSF process may not be economically viable when applied to the typical landfill site.

The existing LFG processing rate at Fresh Kills is "permitted" at 10,000,000 cubic feet per day. If EPA's estimate of the Fresh Kills potential is accurate (at 45 million cubic feet per day) then the current rate of production represents 22% of the site's potential. Mr. Hill noted that the GSF process is capable of producing commercial grade carbon dioxide, if a market exists for CO₂.

The up-coming closing of the Fresh Kills landfill is "good news" for the people of Staten Island. The Fresh Kills reclamation and cleaning of LFG and its off-site use in the local pipeline network is a rare example (and the only one in New York State) of pollution prevention at a landfill resulting in a useful commodity -- pipeline quality natural gas.

However, in the context of this study, the missing element is the "dedication" of that pipeline quality gas for vehicle use. Fresh Kills could serve as an important element in a Staten Island-wide Alternative Fuel Vehicle program. The "pollution prevention" benefits of Fresh Kills-derived gas can serve a second "pollution prevention" agenda -- displacing diesel fuel in medium- and heavy duty vehicles. Even if New York's LNG moratorium is not allowed to lapse, the Fresh Kills gas could be "wheeled" for use as dispensed CNG within Brooklyn Union's service territory.

The most productive use of cleaned gas from Fresh Kills is not for cooking or home heating, but as a vehicle fuel that can displace diesel. Staten Island's historic burden, the Fresh Kills landfill, can be partially mitigated by allowing the natural gas produced there to reduce the Island's dependence on diesel in fleet vehicles.

In some contexts, (on Long Island, for example), it may be more efficient to "exchange" pipeline-quality gas for LNG produced at "peak shaving plants." Of course that requires that New York's LNG moratorium be allowed to lapse. Many LNG plants operate at less than 100% capacity. In a recent conversation with the staff at one facility, we concluded that the plant produces LNG on no more than 60 days per year.

In the context of a regional pipeline network, such as that which connects the Brooklyn Union / Fresh Kills local distribution network with the Holtsville LNG plant (owned by Keyspan) and an extensive network of pipelines and landfills on Long Island, the dispensing of LNG/CNG and the production of cleaned landfill gas could be linked.

The cost-benefits of using landfill gas as a "replacement" for dispensed LNG or CNG need to be examined. An optimistic set of assumptions might include the following:

- the local LNG plant, and/or the local pipeline and CNG dispensing infrastructure, are amortized and function better with gas that has a lower "transportation cost;"
- existing LNG plants and CNG compression stations are more efficient when they serve a larger customer base;
- landfill gas is more "valuable" as an alternative fuel than it is for home heating use;
- the "policy links" between landfill gas and AFVs may serve a broader set of public purposes than merely recovering the gas for retail domestic use.

However, if the economics are not quite on target, particularly because of the state and federal taxes on vehicle fuel, then, at the very least, we need to explore the pollution prevention links between un-taxed municipal landfill sites and un-taxed municipal fleets.

Fresh Kills is important because it is large and offers economics of scale; it has an operational clean-up system that produces 980 BTU pipeline quality gas; it has the potential to produce large quantities of liquid carbon dioxide (a valuable by-product that can displace toxic solvents); it is in an urban context that includes a potentially large customer base of municipal AFVs; it is part of a large existing gas infrastructure network that includes pipelines, a significant number of CNG dispensing stations, and an LNG production facility that may be suitable for increased LNG production for vehicular use. Fresh Kills offers opportunities that are not yet fully realized.

4.0 LANDFILL AND WASTEWATER TREATMENT SITES

4.1 Landfill Sites in New York State

US EPA'S "Opportunities for Landfill Gas Energy Recovery in New York", issued in June of 1996, identified twelve (12) active solid waste landfill sites in New York State. Active sites are deemed to have a "growing potential" for methane generation. The 12 active sites were also on NYS Department of Environmental Conservation (DEC) lists as having current permits.

Approximately twenty-eight (28) closed sites were identified by EPA, of which 13 had current DEC permits. We need to say "approximately" because EPA's list and DEC's list were prepared for different reasons by different people. EPA's list has some missing data in its information fields and may not account for sites "nearby" and "adjacent" to identified sites.

Closed sites are deemed to have a declining gas recovery potential. We assume that closed sites that continue to produce natural gas and/or electricity are on NYS DEC's list because they are "operative" and thus require continued DEC monitoring.

A summary table of active and closed sites, prepared by Vandor + Vandor, can be found on page 17 (a) of this report. Active and closed sites are grouped separately. In each grouping, the sites are listed by the estimated size of each site's gas potential. The right hand column ranks the top 19 sites (those with an estimated gas potential of more than 700 mmcf/yr) relative to each other. The 19 sites are ranked 1 to 10, with several ties.

The DEC permit number is listed, for those active and closed sites that continue to be subject to DEC monitoring. Additional information includes the name of the site, its location, its ownership status (private or government) the contact person or entity, EPA's 1996 total estimated gas potential in million cubic feet per year, EPA's estimated current gas recovery rate, and the un-used potential recovery rate of the site.

Sites that are ranked in the top 10 are listed in **bold** type under the "owner" column when they belong to a government entity ("**GOVT.**"). The possibilities for developing gas reclamation and clean-up programs and linking them to AFV fleets may be stronger on government sites than on private sites because government entities can operate without the burden of the state and federal tax structure (an important consideration when examining the fuel cost of AFVs), and because public fleets are subject to more pollution prevention mandates than private fleets. Public landfill sites may also be able to respond to broad pollution prevention policies and may be able to take advantage of public funding sources such as the New York Environmental Bond Act.

Sites with an EPA estimated potential of more that **700 mmcf/yr** are listed in bold, as are sites with existing recovery rates and un-used potential of more than 700 mmcf/yr. This figure is used because the economics of scale for recovery and clean-up systems,

as discussed in subsequent sections of this report, suggests that only the largest sites will generate enough LFG to justify the expense of constructing a gas clean-up plant.

Eight of the 12 active sites listed are ranked in the top ten. The **Niagara Recycling Facility** seems to have the largest gas production potential in New York, with over 30-billion cubic feet per year. It seems to be operating at its full potential, recovering 30-billion cubic feet of LFG per year and using it to generate electricity. The local utilities include New York State Electric & Gas Corp. and Niagara Mohawk Power Corporation. As the state's largest "gas-to-wire" site the question, from this study's perspective, is how long will the economics of electric production continue to be favorable?

Fresh Kills in Staten Island is ranked second (at a potential of over 16 billion cubic feet per year), with an EPA estimated production rate of over 3.5 billion cubic feet per year. As discussed earlier in this report, (in §3.3), the Fresh Kills site is the only one in the state, and perhaps one of less than a handful nationally, that is producing pipeline quality gas for insertion into the local pipeline system.

The potential gas production rate at the other sites within the "top 10" list, active or closed, falls off significantly after the Niagara Recycling Facility and Fresh Kills. Ten sites fall within the 1- and 2-billion cubic feet per year potential gas production rate. Seneca Meadows in Seneca Falls, Al Turi in New Hampton, and Modern Landfill in Model City are active landfills (with a growing gas potential), each with a potential of over 1-billion cubic feet of LFG production per year.

The closed sites with an LFG potential of over 1-billion cubic feet, in order, are the Blydenburg site in Hauppauge, the Lancaster Gunnville site in Lancaster, the Oceanside site, the High Acres site in Perinton, the Babylon site, the Niagara Landfill Inc. site in Tonawanda, and the Monroe-Livingston site in Caledonia.

The sites mentioned above (all of which are in the top ten relative to their total EPA estimated LFG production potential), open or closed, are worthy of further consideration for LFG-to-LNG/CNG production, even if they are currently withdrawing LFG at the site's maximum rate.

For example, the Blydenburg Sanitary Landfill in Hauppauge, closed in 1985, was "recovering" 1,825 mmscf/yr of LFG in 1996, which was the site's maximum potential. EPA estimated that only 57% of the site area contains wells, that the gas collection efficiency of the site is 85%, that the methane concentration is 50% and that 100% of the collected methane is used to generate electricity by burning it in internal combustion engines. The former Long Island Lighting Company (LILCO), now part of Keyspan purchases the electricity.

Given the remaining productive life span of this landfill, its proximity to an existing natural gas pipeline network, and an existing LNG/CNG infrastructure, its historic sales/purchase agreement with LILCO/Keyspan and the relatively low value of LFG-

LANDFILL SITES IN NEW YORK STATE

ACTIVE SOLID WASTE SITES (Growing gas potential)					1996 EPA ESTIM. POTENTIAL (mmcf/yr.)	1996 EPA ESTIM. RECOVERY (mmcf/yr.)	UN-USED POTENTIAL RECOVERY (mmcf/yr.)	RANK
NAME	DEC #	LOCATION	OWNER PRIV./GOVT.	CONTACT				
NIAGARA RECYCLING FACILITY	32S11	NIAGARA FALLS	GOVT.	HANSON/HUGHES	30,258.5	30,258.5	0.0	1
FRESH KILLS	43F21	STATEN ISLAND	GOVT.	J. BRANSON	18,602.5	3,660.0	12,952.5	2
SENECA MEADOWS LF	50F02	SENECA FALLS	PRIVATE	J. FUNNELL	1,263.1	1,051.2	201.9	5
AL TURI / MIDDLETOWN LFG	38F02	NEW HAMPTON	PRIVATE	SMITH / GAMBINO	1,085.0	1,085.0	0.0	6
MODERN LANDFILL	32S30	MODEL CITY	GOVT.	M. GULLO	1,039.6	0.0	1,039.6	6
BROOME CO. NATICOKE SLF	04S07	BINGHAMTON	GOVT.	R. STANDISH	733.6	0.0	733.6	10
CID SLF	3211	CHAFFEE/SARDINIA	GOVT.	M. GLASNER	707.2	0.0	707.2	10
ELLERY SLF/CHAUTAUQUA LF	07S12	ELLERY	GOVT.	R. JOHNSON	702.2	0.0	702.2	10
CHEMUNG COUNTY	08S02	ELMIRA	GOVT.	V. NYKIEL	668.8	0.0	668.8	
BROOKHAVEN LFGR	52F06	BROOKHAVEN	GOVT.	F. WEHRAN	662.3	662.3	0.0	
ONTARIO CO. SLF	35S11	CANADAigua	GOVT.	K. SPILLANE	490.6	0.0	490.6	
SULLIVAN COUNTY LF	53S03	THOMPSON	GOVT.	J. KEHLENBECK	427.2	0.0	427.2	
					54,640.6	36,717.0	17,923.6	
CLOSED SITES (Declining gas potential)								
BLYDENBURG RD. SLF	52F14	HAUPPAUGE	GOVT.	D. GOUCHOE?	1,825.0	1,825.0	0.0	3
LANCASTER GUNNVILLE	15F11	LANCASTER	PRIVATE	CARROLL/ZELLIF	1,423.5	1,423.5	0.0	4
OCEANSIDE LF	30F13	OCEANSIDE	GOVT.	ZAHREN/ANTIGNANO/JANSEN	1,239.7	635.1	604.6	5
HIGH ACRES GAS	28F02	PERINTON	PRIVATE	MARKHAM/WASTE MGT	1,219.6	315.4	904.2	5
BABYLON MSW LF		BABYLON?	GOVT.		1,164.3	0.0	1,164.3	6
NIAGRA LANDFILL INC.		TONAWANDA	PRIVATE	D. HANSON	1,164.1	?	?	6
MONROE-LIVINGSTON GAS	28F01	CALEDONIA	PRIVATE	MARKHAM/WASTE MGT	1,045.4	584.0	461.4	7
ORANGE COUNTY LF	38F01	GOSHEN	GOVT.	G. JANSEN/LAIDLAW	862.6	730.0	132.6	8
EAST NORTHPORT LFG	52F15	EAST NORTHPORT	GOVT.	F. WEHRAN	832.5	336.4	496.1	8
TROY SLF		RENSSELEAR	GOVT.	E. BECHARD	792.7	0.0	792.7	9
RIVERHEAD YOUNGS AVE. SLF		RIVERHEAD	GOVT.	J. REEVE	711.8	146.0	565.8	10
OLD BETHPAGE	30F07	OYSTER BAY	GOVT.	ZAHREN/ANTIGNANO/JANSEN	681.7	277.4	404.3	
PORT WASHINGTON LF, L-5		NORTH HEMPSTEAD	GOVT.	N. HEMPSTEAD DPW	585.3	?	?	
ORLEANS SLF		CLARENCE?	PRIVATE	ORLEANS SLF INC	520.9	0.0	520.9	
SMITHTOWN WEST	52F04	SMITHTOWN	GOVT.	ZAHREN/ANTIGNANO/JANSEN	518.8	204.4	314.4	
ONONDAGA / ENERGY TACTICS	34F01	ONONDAGA	PRIVATE	ZAHREN/ANTIGNANO/JANSEN	515.8	178.9	336.9	
QUEENSBURY LF		QUEENSBURY	GOVT.	J. COUGHLIN	500.3	0.0	500.3	
CLIFTON PARK		CLIFTON PARK	GOVT.	J. RILEY	478.4	0.0	478.4	
SIX TOWN AUSTRO BROS. SLF		WATERTOWN	GOVT.	M. SLIGAR	471.5	0.0	471.5	
SARATOGA SPRINGS	46F01	SARATOGA SPGS.	GOVT.	T. McTYGUE	468.2	?	?	
LAIDLAW INCORPORATED SLF		FELTS MILLS	PRIVATE	LAIDLAW WASTE SYSTEMS	467.5	0.0	467.5	
MOHAWK VALLEY GAS	22F01	FRANKFORT	PRIVATE	MARKHAM/WASTE MGT	438.8	279.3	159.5	
NORTH SEA LF		NORTH SEA	GOVT.	B. GILBRIDE	425.7	0.0	425.7	
CENTRAL SERVICE LF		ROOT	GOVT.	K.J. BUTTON	417.8	0.0	417.8	
EAST HAMPTON SLF		EAST HAMPTON	GOVT.		410.2	0.0	410.2	
COLONIE SLF		COLONIE/ALBANY	GOVT.	F. STOCKBRIDGE	290.2	0.0	290.2	
GREATER ALBANY SLF		ALBANY	GOVT.	K. V. BYNG	262.2	0.0	262.2	
SMITHTOWN/ZAPCO?	52F13	SMITHTOWN	PRIVATE	ZAHREN/ANTIGNANO/JANSEN	0.0	0.0	0.0	
					19,734.5	6,935.4	12,799.1	
							30,722.7	

generated electricity, would this site prove more productive as a producer of pipeline quality gas?

The same set of questions can be applied to all of the top ten sites, other than Fresh Kills, which is already producing pipeline quality gas.

4.2 Priority List of New York State Landfill Sites

If one were to examine each of the top ten sites in order of quantitative potential and each site's growing or declining gas production rate, the following might be a reasonable "first cut" priority list of sites that should be reviewed further:

1. The **Niagara Recycling Facility** in Niagara Falls, produces over **30-billion** cubic feet of gas per year for the generation of electricity. It is government owned.
2. The **Oceanside** landfill is a closed and government-owned. It has an annual potential LFG production of **1.2-billion** cubic feet. In 1996 the site was processing 635-million cubic feet of LFG for electric production in internal combustion engines.
3. The **Modern Landfill** in Model City is an open government-owned site with an annual potential LFG production of **1.0-billion** cubic feet which, in 1996, was not processing any LFG.
4. The **Al Turi Landfill** in New Hampton is an open private site with an annual potential LFG production of **1.0-billion** cubic feet, which in 1996 was processing all of its LFG to produce electricity in internal combustion engines. Al Turi was the site for a demonstration of the Acron gas clean-up technology. (See §5.1.) Their electric generating contracts will run out soon. They have an LFG collection system in place and a track record which favors "innovative" technologies.
5. The **Babylon Landfill** is government-owned with a potential of over **1.1-billion** cubic feet per year. EPA's 1996 data was not complete regarding the site's LFG reclamation rate, but we are certain that if any gas is produced, it is not being cleaned for insertion into the local pipeline. This site is one of several, with recovery systems and electric generating capacity, located on Long Island. If New York's LNG moratorium is allowed to lapse, some of Long Island's landfill sites might be able to produce pipeline quality gas in trade for LNG produced at Keyspan's Holtsville peak shaving plant.

4.3 New York State's Natural Gas Pipeline Network

New York State has an extensive natural gas pipeline network that covers much of the state south of a line running along the southern edge of Lake Ontario through Rome, NY and Glenn Falls, NY. Most of the state's more-densely populated counties and most of its major city's are served by natural gas pipelines, including the Long Island / New York City metropolitan area, the Hudson river corridor to Albany and Rensselaer, west to Schenectady, Utica, Syracuse, Rochester and Buffalo. All of the Long Island landfills are within the pipeline network that covers Nassau and Suffolk Counties.

If a site's projected future LFG generating potential is limited (either because of its size, or the site's age) the cost of extending the nearest pipeline to the landfill becomes an important negative in evaluating the economic viability of that site. An existing LFG collection system is essential if a site is to be considered as a possible pipeline quality gas producer. It is also important that the LFG cleaning process be modular, pre-

fabricated, and portable, so that at the end of the productive life of the landfill the capital investment of the clean-up system can be transferred to another site.

Relative to the five landfill sites listed above, the following is the availability of local pipelines:

- The **Niagara Recycling Facility** in Niagara Falls and the **Modern Landfill** in Model City are located in an area served by several large pipeline companies, including the Tennessee Gas Pipeline, National Fuel Supply, and the Empire State Pipeline.
- The **Oceanside Landfill** (and all of Long Island, including the **Babylon** site), is served by the Iroquois Pipeline, and the LILCO/Keyspan network, which are connected to the Brooklyn and Staten Island Keyspan/Brooklyn Union pipeline system and Con Edison's system in northern Queens, Manhattan and Westchester.
- The **Al Turi Landfill** in New Hampton (near Goshen) is within the Central Hudson Gas and Electric network.

In general terms, the location of natural gas pipelines and the networks of local gas delivery systems tend to follow the location of high density counties and cities. The production of solid waste and the location of landfill sites tends to follow similar patterns. Thus, the portions of the state with the lowest densities -- including the vast Adirondacks -- tend to have the least extensive pipeline network and the fewest landfill sites. By contrast, the east-west Interstate 90 corridor, for example, tends to have an extensive pipeline network and a significant number of landfills.

4.4 Landfill Sites in Maryland

Maryland seems to have more landfill sites than New York, but none with the LFG production potential of New York's Niagara Recycling Facility or the Fresh Kills site and none with any significant recovery systems.

US EPA'S "Opportunities for Landfill Gas Energy Recovery in Maryland", issued in June of 1996, identified twenty-one (21) active solid waste landfill sites in Maryland. Active sites are deemed to have a "growing potential" for methane generation.

Approximately eighteen (18) closed sites were identified by EPA. As in our analysis of New York sites, we need to say "approximately" because EPA's list has some missing data in its information fields and may not account for sites "nearby" and "adjacent" to identified sites. Closed sites are deemed to have a declining gas recovery potential.

A summary table of active and closed sites, prepared by Vandor + Vandor, can be found on page 19 (a) of this report. Similar to the list of New York landfill sites, discussed above, Maryland's active and closed sites are grouped separately. In each grouping, the sites are listed by the estimated size of each site's gas potential. The right hand column ranks the top 8 sites (those with an estimated gas potential of more than 700 mmcf/yr) relative to each other.

LANDFILL SITES IN MARYLAND

ACTIVE SOLID WASTE SITES (Growing gas potential)				WASTE FLOW (TONS/DAY)	1996 EPA ESTIM. POTENTIAL (mmcf/yr.)	1996 EPA ESTIM. RECOVERY (mmcf/yr.)	UN-USED POTENTIAL RECOVERY (mmcf/yr.)	
NAME (LOCAL GAS CO. / Status?)	LOCATION	OWNER PRIV./GOVT.	CONTACT					RANK
BROWN STATION ROAD (BG&E)	UPPER MARLBORO	GOV	B. FLETCHER	1,200	1,533.1	27	1,506.1	1
MILLERSVILLE/SUDLEY ROAD (BG&E)	SEVERN	GOV	J. PITTMAN	1,800	1,416.2	0	1,416.2	2
OAKS (BG&E)	LAYTONSVILLE	GOV	R. WILSON	2,100	1,296.1	0	1,296.1	3
QUARANTINE ROAD (BG&E) (Ash, debris?)	BALTIMORE	GOV	O. SWASSORD	2,000	1,115.9	0	1,115.9	4
SANDY HILL (BG&E) (Gas Collection?)	BOWE	GOV	F. QUIRUS	1,094	1,032.5	0	1,032.5	5
ALPHA RIDGE (BG&E) (May be closed?)	MARRIOTTSTVILLE	GOV	J. OHARA	700	790.0	0	790.0	6
EASTERN (BG&E) (Venting, Planned Collection?)	TOWSON	GOV	S. LIPPY	700	788.5	0	788.5	7
REICHS FORD (Planned Collection?)	FREDERICK CNTY.	GOV	R. HAYES	300	778.8	0	778.8	8
NEULAND PARK	SALISBURY	GOV	R. SHARMA	300	676.4	0	676.4	
ST. ANDREWS	CALIFORNIA, MD	GOV	D. KHNIEWSKI	26-100	598.7	0	598.7	
FRESH ROAD II (Gas Collection?)	HAGERSTOWN	GOV	R. DAVENPORT	1,400	569.4	0	569.4	
HOGG HILL/CENTRAL	ELKTON	GOV	K. NAUMAN	101-500	453.4	0	453.4	
HOBBS ROAD	CAROLINE CNTY.	GOV	C. EMMERSON		434.3	0	434.3	
FORT MEADE (BG&E)	FORT MEADE	GOV	C. FOY		421.4	0	421.4	
ANNAPOLIS	ANNAPOLIS							
BARSTOW				101-500				
BEULAH/GOLDEN HILL				101-500				
HOODS MILL ROAD				101-500				
MIDSHORE REGIONAL	EASTON			400				
MOUNTAIN VIEW	FROSTBURG			101-500				
NORTHERN	WESTMINSTER			300				
					11,904.7	27	11,877.7	
CLOSED SITES (Or "special") (Declining gas potential)								
GUDE (BG&E)	ROCKVILLE	GOV	F. WONG	983.3	584	399.3	184.7	
PISGAH	CHARLES CNTY.	GOV	D. FLEMING	26-100	485.6	0	485.6	
VALE SUMMIT	ALLEGANY CNTY.	GOV	S. YOUNG		481.1	0	481.1	
PENNINGTON AVE. (Capped Wells?) (BG&E)	BALTIMORE	GOV	MD RECYCLING	470.5	328.5	142.0	186.5	
AGRICYCLE INC.								
APPEAL SMA	LUSBY							
BRANDYWINE RUBBLE	FAIRMONT HGTS.			1,000				
CAMBRIDGE	CAMBRIDGE?							
CENTRAL				26-100				
CENTREVILLE				26-100				
DAYS COVER ROAD	BALTIMORE							
FIRST	BALTIMORE							
MEYER RUBBLE				101-500				
NICHOLSON				26-100				
PATUXENT RIVER	PATUXENT RIVER							
RITCHIE LAND RECLAMATION				101-500				
ROUND GLADE	OAKLAND							
SCARBORO/HARFORD				26-100				
					1,295.2	142.0	1,153.2	
							13,030.9	

The table includes the name of the site, its location, its ownership status (private or government) the contact person or entity, the site's estimated waste flow in tons per day, EPA's 1996 total estimated gas potential in million cubic feet per year, EPA's estimated current gas recovery rate, and the un-used potential recovery rate of the site.

Sites that are ranked in the top 8 are listed in **bold** type under the "owner" column when they belong to a government entity ("**GOVT.**"). As discussed above in §4.1, the possibilities for developing gas reclamation and clean-up programs and linking them to AFV fleets may be stronger on government sites than on private sites because government entities can operate without the burden of the state and federal tax structure and because public fleets are subject to more pollution prevention mandates than private fleets.

Sites with an EPA estimated potential of more than **700 mmcf/yr** are listed in bold. This figure is used because the economics of scale for recovery and clean-up systems, as discussed in subsequent sections of this report, suggests that only the largest sites will generate enough LFG to justify the expense of constructing a gas clean-up plant.

The top five sites each have a potential gas production rate of over 1-billion cubic feet per year. The potential gas production rate at the next three sites within the "top 8" list, falls off to 778- to 790-million cubic feet per year. All 8 sites are worthy of further consideration for LFG-to-LNG/CNG production. Seven out of the 8 are in the service territory of Baltimore Gas & Electric (BG&E). The issue in Maryland is the proximity of existing pipeline networks relative to the top 8 landfill sites.

Because the eastern shore of the state is mostly without a natural gas pipeline network, landfill sites in the east will only be viable as natural gas producers if they can provide on-site CNG or on-site LNG production. This issue is discussed further in the §7.0, Findings.

4.5 Landfill Gas Reclamation

Landfill gas reclamation is a relatively mature technology that is used routinely at a large number of facilities throughout the country. One option is to drill vertical "wells" at regular intervals which are connected to horizontal collection network.

Another design consists of perforated pipes running horizontally under the landfill, with various layers of gravel and other materials to encourage gas migration into the pipes, connected to vertical "wells" that bring the gas up. The horizontal and vertical pipes are connected to flares and/or to a suction powered central gathering system that moves the LFG to a processing system.

In a June 1997 report prepared by the City of Albany and Landfill Technologies, Inc., for the New York State Energy Research and Development Authority (NYSERDA), titled "Albany Interim Landfill Gas Extraction and Mobile Power System, Using Landfill Gas to Produce Electricity," the following points were made relative to LFG reclamation:

- The report indicates the "efficiency and effectiveness of constructing horizontal gas extraction conduits in a landfill during normal operation, as opposed to conventional technology involving construction of vertical wells after landfill closure."
- Horizontal gas extraction can capture the maximum gas generated at a cost that "is much less than the cost of drilling large-diameter vertical wells."
- Horizontal conduits, by allowing LFG recovery to occur prior to the closing of the landfill, allows odor control and energy recovery to occur sooner.
- "The effective radius of influence of the horizontal extraction conduits was found to be about 50 feet; thus, a horizontal pipe-to-pipe separation of about 100 feet appears appropriate."
- "Vertical separation of the horizontal galleries should be about 30 to 50 feet."
- The report suggests that Enviro-Scrub (a trademarked liquid reagent) was "successful in dramatically reducing hydrogen sulfides... [and] the reagent consumption [was] reasonable for gas flows associated with small power production, e.g., 100 kW at the lower hydrogen sulfide concentrations (5 to 200 ppm) typically experienced at landfills."

The report did not address the possible problems associated the "shifting ground" under landfills. As the decomposition process continues the volume of material under the horizontal collection pipes may sink, crating breaks in the pipes, and possibly limiting the collection efficiency of the system.

Many landfills have existing reclamation systems in place. Some are operating with the added benefit of federal §29 tax abatements. It is important to estimate the LFG recovery rate of any site on the basis of accurate measurements of the volume of gas flow and the gas' chemical composition, before it enters the on-site flare system. Some estimates may be too high because the LFG contains a good deal of air as well as water. Processing excessive air or water through a clean-up system is an inefficient proposition. In addition, excessive air in LFG will yield gas with a high nitrogen content, an impurity that is difficult to remove.

While we characterize landfills as "renewable energy sources," we need to remember that most landfills will have a limited peak LFG production cycle of between 10 and twenty years, that production rates will be lower during the early and later years and that LFG production and the methane content of the gas will vary month to month and year to year. Thus, larger sites, prior to their closure will be the most suitable for LFG-to-CNG/LNG projects.

By contrast, wastewater treatment plants tend to produce digester gas at a steadier and more predictable rate and with a higher concentration of methane. However, as will be evident in the following section of this report, the largest wastewater treatment plants in New York City produce less digester gas than most medium sized landfill sites.

LANDFILL SITES IN MARYLAND

ACTIVE SOLID WASTE SITES (Growing gas potential)				WASTE FLOW (TONS/DAY)	1996 EPA ESTIM. POTENTIAL (mmcf/yr.)	1996 EPA ESTIM. RECOVERY (mmcf/yr.)	UN-USED POTENTIAL RECOVERY (mmcf/yr.)	RANK
NAME (LOCAL GAS CO. / Status?)	LOCATION	OWNER PRIV./GOVT.	CONTACT					
BROWN STATION ROAD (BG&E)	UPPER MARLBORO	GOV	B. FLETCHER	1,200	1,533.1	27	1,506.1	1
MILLERSVILLE/SUDLEY ROAD (BG&E)	SEVERN	GOV	J. PITTMAN	1,600	1,416.2	0	1,416.2	2
OAKS (BG&E)	LAYTONSVILLE	GOV	R. WILSON	2,100	1,296.1	0	1,296.1	3
QUARANTINE ROAD (BG&E) (Ash, debris?)	BALTIMORE	GOV	O. SWASSORD	2,000	1,116.9	0	1,116.9	4
SANDY HILL (BG&E) (Gas Collection?)	BOWE	GOV	F. QUIRUS	1,094	1,032.5	0	1,032.5	5
ALPHA RIDGE (BG&E) (May be closed?)	MARRIOTTSVILLE	GOV	J. O'HARA	700	790.0	0	790.0	6
EASTERN (BG&E) (Venting, Planned Collection?)	TOWSON	GOV	S. LIPPY	700	786.6	0	786.6	7
REICHS FORD (Planned Collection?)	FREDERICK CNTY.	GOV	R. HAYES	300	776.8	0	776.8	8
NEWLAND PARK	SALISBURY	GOV	R. SHARMA	300	676.4	0	676.4	
ST. ANDREWS	CALIFORNIA, MD	GOV	D. ICHNIEWSKI	26-100	598.7	0	598.7	
RESH ROAD II (Gas Collection?)	HAGERSTOWN	GOV	R. DAVENPORT	1,400	569.4	0	569.4	
HOGG HILL/CENTRAL	ELKTON	GOV	K. NAUMAN	101-500	453.4	0	453.4	
HOBBS ROAD	CAROLINE CNTY.	GOV	C. EMMERSON		434.3	0	434.3	
FORT MEADE (BG&E)	FORT MEADE	GOV	C. FOY		421.4	0	421.4	
ANNAPOLIS	ANNAPOLIS							
BARSTOW				101-500				
BEULAH/GOLDEN HILL				101-500				
HOODS MILL ROAD				101-500				
MIDSHORE REGIONAL	EASTON			400				
MOUNTAIN VIEW	FROSTBURG			101-500				
NORTHERN	WESTMINSTER			300				
					11,904.7	27	11,877.7	
CLOSED SITES (Or "special") (Declining gas potential)								
GUDE (BG&E)	ROCKVILLE	GOV	F. WONG	983.3	584	399.3	184.7	
PISGAH	CHARLES CNTY.	GOV	D. FLEMING	26-100	485.6	0	485.6	
VALE SUMMIT	ALLEGANY CNTY.	GOV	S. YOUNG		481.1	0	481.1	
PENNINGTON AVE. (Capped Wells?) (BG&E)	BALTIMORE	GOV	MD RECYCLING	470.5	328.5	142.0	186.5	
AGRICYCLE INC.								
APPEAL SMA	LUSBY							
BRANDYWINE RUBBLE	FAIRMONT HGTS.			1,000				
CAMBRIDGE	CAMBRIDGE?							
CENTRAL				26-100				
CENTREVILLE				26-100				
DAYS COVER ROAD	BALTIMORE							
FERST	BALTIMORE							
MEYER RUBBLE				101-500				
NICHOLSON				26-100				
PATUXENT RIVER	PATUXENT RIVER							
RITCHIE LAND RECLAMATION				101-500				
ROUND GLADE	OAKLAND							
SCARBOROUGH/FORD				26-100				
					1,295.2	142.0	1,153.2	
							13,030.9	

4.6 Wastewater Treatment Sites in New York

Of the more than 100 Municipal Anaerobic Digester Facilities in New York State, New York City's Department of Environmental Protection's (DEP) 14 facilities are larger than most others in the state. The following is a list of NYC DEP wastewater treatment sites with each facility's DEP estimated 1998 digester gas production rate, in cubic feet of gas:

1. Newton Creek	615,503,000
2. Wards Island	587,780,000
3. Jamaica	426,027,000
4. North River	284,562,708
5. Bowery Bay	264,306,000
6. Hunts Point	244,553,531
7. Coney Island	160,929,000
8. 26th Ward	147,368,000
9. Owls Head	139,471,000
10. Oakwood Beach	98,779,000
11. Port Richmond	75,527,000
12. Tallman Island	63,197,000
13. Rockaway	29,059,000
14. Red Hook	No data

DEP estimates that as much as 20% to 100% of the digester gas is "wasted" at each site, presumably flared. For example, at the largest site, the Newtown Creek facility, DEP estimates that 46% of the digester gas is used on-site, (perhaps to heat buildings) and the remaining 54% is flared.

Vandor + Vandor has proposed to undertake a small study for NYC DEP to evaluate the extent to which digester gas is used on-site and if the clean-up systems reviewed in this study can, cost-effectively, produce pipeline quality methane. Our proposal for that study is under review by NYC DEP.

It is clear that even if the entire flow rate of the Newtown Creek facility were fully utilized in a clean-up system, such as the Kryos Process, the daily gas flow rate of Newtown Creek, (only 1.68 million cubic feet) is about 50% of the gas flow rate of the smallest viable Kryosol Process LFG cleaning plant. At first glance, wastewater treatment plants are not ideal candidates for producing pipeline quality methane (or CNG/LNG) because the volume of gas is relatively low compared to the capital cost of the clean-up system.

On the other hand, digester gas is "richer" than LFG, allowing for a more efficient clean-up system. The methane content of digester gas is close to 65%, while the methane content of LFG ranges from 55% to 58%. As a public investment, wastewater treatment plants offer a "permanent renewable resource" that if not tapped are permanent sources of emissions, in urban areas that are often "non-attainment zones."

Other factors that may enhance the viability of a wastewater digester gas clean-up system include the following:

- ready availability of on-site electricity to run the equipment,
- lower cost of retrofitting a wastewater treatment plant,
- ease of construction and operation in the context of an existing "building" or campus, as compared to an open landfill,
- availability of existing on-site technicians to operate the clean-up system,
- the "nearby" gas pipeline that will move the cleaned gas to off-site LNG plants or CNG dispensers will tend to be "just outside the fence,"
- the emission reduction benefits of an urban wastewater treatment plant has a higher "public visibility" than the pollution prevention at a distant landfill sites,
- the local municipality is an excellent "market" for its own CNG/LNG product, and
- to the extent that CO₂ is a byproduct, the market for its use (especially as a substitute for "perc") is likely to be more extensive in the urban context of the wastewater treatment plant.

The most dramatic long-term result of this study may well turn out to be the generation of low-cost CNG/LNG by municipal wastewater treatment plants for use in municipal AFV fleets.

The pollution prevention benefits of linking digester gas to AFVs (and the possible added benefit of liquid CO₂ production), on a long term basis may well outweigh the lower efficiency (gas flow rate) of a large wastewater treatment plant. If that model can be sustained, by a fully operational system, say in New York City, the replication of that system and its "downsizing" to fit smaller wastewater treatment plants could open the door to linking urban AFVs to a permanent urban renewable energy source.

4.7 Wastewater Treatment Sites in Maryland

Given that a critical mass of digester gas flow is needed to create an economically viable digester gas-to-CNG/LNG plant, and given that New York City's wastewater treatment plants have flow rates that are less than most mid-sized LFG flow rates, and given that New York has some of the largest wastewater treatment plants in the country, we concluded that follow-up work regarding the viability of New York's plants will need to be completed before smaller facilities, such as those in Maryland are examined.

5.0 GAS CLEANING METHODS

5.1 Acrion Technologies, Inc.

Acrion Technologies, Inc., is a chemical process consulting company based in Cleveland, Ohio. Acrion's expertise includes landfill gas process design, as demonstrated at the Al Turi landfill in Goshen, New York, and elsewhere.

Landfill gas (LFG) is generally made up of equal parts methane and carbon dioxide (CO₂) as well as water and a variety of contaminants. Raw LFG, at 70 degrees Fahrenheit and one atmosphere pressure, is always saturated with water vapor. The water content of the gas is approximately 2.5%, or about 140 gallons per million cubic feet of gas.

In the Acrion clean-up process, much of the water is removed by condensation in knockout drums before and after the initial compression of the gas. In addition the gas flow is further dehydrated to prevent ice formation during the CO₂ wash process.

Contaminants differ from landfill to landfill and over the life span of each facility. Other than nitrogen and water, contaminants make up 1% of raw LFG. Contaminants containing chlorine and sulfur are the most common.

Acrion's process starts with methanol for dehydration and then relies on CO₂ obtained from LFG to "wash" the volatile organic compounds (VOCs) from the LFG. Raw LFG is dried, compressed and fed to an absorption column. The column has cooling supplied at its top (condenser) which causes CO₂ in the LFG to condense and form an absorbent liquid which trickles down the column. Within the column, high-surface-area packing promotes intimate contact between the upward-flowing LFG and the downward-flowing liquid CO₂ absorbent, assuring complete transfer of contaminants from the raw LFG to the liquid CO₂ absorbent.

Clean gas, containing only methane and CO₂, leaves the top of the column. This gas can be used as medium-BTU fuel (up to 800 BTU/scf) or it can be upgraded to pipeline quality methane (98% methane) by removal of more CO₂. Additional CO₂ removal can be accomplished by high pressure absorption, using a physical solvent, such as methanol. One brand-name solvent is Selexol, a widely available, non-proprietary product. The estimated cost of removing the CO₂ to less than 2% of the gas is in the range of 30¢ to 50¢ per MMBTU. The solvent is regenerated by pressure reduction (5-10 psia) which causes dissolved CO₂ to bubble off, much as it does when a bottle of soda is left open.

Residual CO₂ can also be removed by passing the gas through a membrane. It should be noted that because the gas has been cleaned of trace contaminants, the membranes should last two to four years before needing to be replaced.

Another option is to pass the gas through a molecular (mol) sieve bed where the remaining CO₂ (but within limits) is removed by adsorption. Mol sieve is regenerated

by pressure reduction and heating. Two sieve beds are employed, one adsorbing, one regenerating, or desorbing.

Liquid CO₂ absorbent, laden with contaminants, leaves the bottom of Acrion's CO₂ wash column, is heat-exchanged to recover cooling, and is incinerated in the landfill flare with relatively low NO_x and other emissions.

Most of the CO₂ separated from the LFG in Acrion's process is recovered as merchant liquid CO₂, i.e., "food grade," at 0-degrees Fahrenheit and 300 psia. Merchant liquid CO₂ has a market value, delivered to a customer, from \$40 to several hundred dollars per ton. One possible market for the clean liquid CO₂ might be as a plant-growth enhancer in commercial greenhouses. Another possible use may be as a substitute for some of the more volatile compounds used in dry-cleaning systems. Those aspect of Acrion's system are particularly appealing in the context of Maryland's commercial greenhouse industry and in any urban context that has dry-cleaning establishments adjacent to residential uses.

One benefit of the Acrion system is that the contaminant separating agent, the liquid CO₂, is obtained directly and continuously from raw LFG, eliminating purchase, storage, regeneration and disposal of separating agents such as organic solvents and solid sorbents. The process avoids the need for "hazardous solvents" to remove VOCs. Acrion has demonstrated at the Al Turi Landfill that vinyl chloride and Freon-12, the most volatile and difficult to remove VOCs, were removed to below detection limits of 20 and 10 ppb (billion), respectively.

Acrion estimates that for the production of pipeline quality gas (and liquid CO₂), 18% of the LFG would be consumed to power the processing equipment. In general terms, the larger the LFG flow, the more efficient and economical the clean-up system becomes.

The nitrogen content of LFG increases as more air is drawn into the gathering system. In order to avoid excessive nitrogen content (above 3%) the gathering system must be properly "managed." One approach is to segregate the perimeter wells from the interior wells. The perimeter wells tend to draw more air, yielding higher concentrations of nitrogen, while the interior wells will yield lower concentrations of nitrogen. The LFG from the perimeter could be flared, while the LFG from the interior would be the source for the clean-up system. The rate of "drawing-in" the LFG stream needs to be managed as well. The slower the rate the less air will be sucked in.

Most on-site liquefaction processes (discussed in §6.0 of this report) can only liquefy dry, clean methane as a feedstock. Thus, the Acrion process and the Kryos Energy process, discussed in the next section, are pre-treatment steps that must occur prior to liquefaction. SRI International's work, discussed in §5.5, offers some hope for dealing with LFG with high nitrogen content.

With regard to sulfur content, Acrion's proposed 1999 work program for Brookhaven National Laboratory includes tasks related to the modification of their process to account for high sulfur content gas, such as from wastewater treatment plants.

5.2 Kryos Energy Inc.

Kryos Energy Inc., at 171 Madison Avenue, New York, (Tel. No. 212 685 8055) has developed an LFG processing system, the Kryosol Process, that yields pipeline quality gas. Food grade liquid CO₂ can also be recovered as a by-product. CO₂ recovery requires the addition of a CO₂ purification/liquefaction skid. The president and vice president of Kryos Energy Inc. are Stephen J. Markbreiter and Irving Weiss, respectively.

The Kryosol Process is a refrigerated physical absorption process which relies on commercial grade methanol as the physical solvent. Methanol is an excellent physical solvent because it is readily available and because it can remove water and condensates from the LFG stream in a separate process, independent of any CO₂ removal.

The Kryosol Process begins by **1)** gathering the raw LFG and then **2)** compressing it to approximately 20 psi above product pipeline pressure, but no lower than 400 psi. (In some circumstances the on-site dispensing of the cleaned gas, as CNG, is achievable at a relatively low operating cost.)

After the heat of compression is removed, methanol is injected directly into the pressurized LFG stream, permitting the gas to be chilled to approximately minus 23 degrees Fahrenheit, without freeze-up and without hydrate formation. The water-methanol-heavy hydrocarbon components are removed **3)** as liquid, to be treated **5)** in a methanol recovery section.

The pretreated pressurized LFG is processed **4)** to separate CO₂ from the methane. The gas enters the scrubbing tower where chilled methanol absorbs CO₂, producing a dry and clean pipeline quality gas which is re-heated and delivered as product.

The CO₂ rich methanol goes through a series of flash steps **6)** and low level heating in order to enhance CO₂ degasification and simultaneously purify the methanol. The purified methanol is recycled for use in the scrubbing tower.

During the degasification of the methanol, a bone dry CO₂ byproduct is produced. After the CO₂ gas is re-heated to near ambient temperature, it leaves the purification system at near ambient pressure. The CO₂ contains some methane and traces of methanol. It is then vented to the atmosphere or sent to the CO₂ recovery unit where it is further compressed to approximately 250 psi. It is then chilled to near its dew point in order to condense out the major portion of the methanol which is then returned to the recovery section for reprocessing. Charcoal is used to remove chlorides. Catalytic deoxidation is the final cleaning step that removes anything that escapes the previous purification steps. The resultant CO₂ is "food grade."

As a practical matter the major wholesale entities that control the CO₂ market are reluctant to purchase food grade CO₂ from landfill sites. Kryos Energy believes that establishing the market for non-food grade CO₂, such as for replacing "perc" as a dry-

cleaning product, will not be easy because the wholesalers will want to keep food grade and non-food grade CO₂ in separate collection, storage and distribution streams -- a potentially costly proposition.

Still, the potential income (possibly over \$500,000 per year) from CO₂ production, at approximately 85 tons/day at a 3.0 mmscf/day LFG processing plant, is too significant to ignore. As more LFG clean-up systems go on line and as the potential production rate for clean CO₂ increases, the LFG industry will have to convince the CO₂ wholesalers that clean CO₂ from landfills and wastewater treatment plants needs to be included in the general CO₂ market stream.

The Kryosol Process assumes that typical LFG consists of 55-58% methane, 42-45% CO₂, 1%-2% "inerts" such as oxygen and nitrogen, water at saturation levels, some H₂S, 100 to 500 ppm C₂ - C₁₀, 500 to 1500 ppm BTX and miscellaneous compounds, including chlorides, olefins, ketones of up to 500 to 1,000 ppm. The typical heating value of (dried) LFG is approximately 600-650 BTU/scf.

The Kryosol Process is designed to remove all of the components listed, so as to deliver a pipeline quality methane stream (CH₄) with a maximum CO₂ concentration of 2%. The H₂S content of the gas is no greater than 1/4 Grain /100 scf, or 4 ppm by volume. The heating value of the dry gas is between 960-980 BTU/scf. The process yields gas recovery rates of 97% to 98%. The methanol used in the process is mostly recycled. Waste products (consisting of a mix of BTXs and chlorides) of approximately one barrel per week at a 1.0 mmscf/d processing facility, are collected in drums and disposed off-site per sanctioned disposal methods.

A Kryosol LFG upgrading plant was installed at the Empire landfill (Scranton, PA) in mid-1998. It can process 9.0 mmscf/d of saturated LFG. The plant is producing clean, dry pipeline quality gas with a heating value of approximately 960-980 BTU/scf.

Two other plants, one in Ohio and one in Michigan, are under construction. As those plants come on line, the Kryosol Process will be the most widely used LFG-to-pipeline-quality-gas system in the United States. From the perspective of this study, the Kryosol Process is demonstrating one important element in linking pollution prevention at landfill sites and at fleets. The missing link is the policy connection between a CNG/LNG dispensing network that relies on lower priced "wheeled" gas from the landfill, and on existing, efficient, amortized CNG/LNG production sites for the dispensing of lower cost CNG/LNG. Those "links" are covered in more detail in §7.0, Findings, later in this report.

5.3 Kryosol Process Design Criteria

The Kryosol Process is based on the following design criteria:

1. The use of system modules to minimize field construction, improve portability and reduce capital costs.
2. Minimize methane losses and thus achieve the maximum possible quantity of pipeline quality gas.
3. Simple operating procedures that allow a single shift to run the system.

4. Minimize power consumption and eliminate fuel requirements for regeneration of reboilers, reclaimers, glycol units, pretreatment units and other similar steps common to other clean-up systems.
5. The removal and collection of all undesirable compounds in bulk liquid form, thus dramatically reducing atmospheric emissions.

Kryos Energy Inc. claims the following advantages for the Kryosol Process:

1. The liquid to gas ratio required to make pipeline quality gas is small. Consequently, all the components of the gas separation process are smaller, allowing for shop fabrication of the equipment rather than extensive construction in the field.
2. Methane losses are very low, resulting in more high-BTU gas. Most other processes use part of the methane stream to fuel regeneration as stripping equipment, thus reducing the net pipeline quality product. For example, chemical absorption systems that use amine or glycol require high temperature stripping. Similarly, physical solvents, other than methanol, require high temperature stripping (vaporizing and venting) of undesirable compounds that are absorbed in the solvent and which, without treatment, would destroy the solvent's ability to produce high-BTU gas.
3. All water is removed by condensation and absorption. The Kryosol Process delivers bone dry product gas and CO₂, eliminating corrosive acid formation.
4. All C₆ and heavier paraffinic hydrocarbons are thoroughly removed prior to the absorption process. In addition 99% of all other undesirables, such as BTX's organic chlorides, oxygenated organic compounds... are removed, thus avoiding atmospheric venting of undesirables.
5. CO₂ is removed without the need for regenerative stripping and/or vacuum pumping. No power, fuel, or stripping medium is required for the methanol-CO₂ separation.
6. The only solvent used is methanol, which is inexpensive and readily replaceable.
7. The process will operate in a cold environment. Methanol and methanol/water solutions will not freeze at atmospheric conditions. Most other systems require routine injections of anti-foam inhibitors, corrosion inhibitors, solvent absorption promoters, dilution fluids (pure water), and/or anti-oxygenation agents -- all requiring on-site storage.
8. The bulk of the trace organic chlorides are removed at below ambient temperatures in liquid form, thus neutralizing its corrosiveness.

The Kryosol Process has the following two "disadvantages:"

1. Methanol has high vapor pressures at the operating temperatures of the process. Thus, some methanol losses will occur.
2. Methanol is flammable. Some localities will require that the methanol storage be located underground, or be contained behind concrete barriers. In an urban context, such as a New York City wastewater treatment plant, the on-site storage of methanol will require Fire Department review.

5.4 Kryosol Process Cost Estimates

The larger the landfill the more efficient the relationship between the capital costs of the Kryos process and the pipeline-quality gas production rate, as per the estimates

outlined below by Mr. Ralph Greenberg, Consulting Engineer, 795 White Oak Drive, Santa Rosa California 95409, at telephone number (707) 537 1068, and Fax number (707) 537 0910. The capital and operating cost of the Kryos process will vary site by site. For example, the proximity of a natural gas pipeline will impact capital costs, as will the proximity of electric lines. The estimates listed bellow assume that an on-site recovery and flare system is in place. If not, the capital costs will rise to reflect the cost of installing an LFG recovery system.

1. A **3.0 mmscf/d** (million standard cubic feet per day) LFG producing site will yield about **1.65 mmscf/d** of pipeline quality gas (a heating value of 960-980 BTU/scf), with a turnkey cost of approximately **\$4,000,000**, exclusive of LFG wells and gathering pipes. The production facility would require a daily expenditure of approximately **950 kW** of electricity if it did not use some of the LFG for running the process. If a gas-drive alternative is chosen, raise the capital costs to approximately **\$4,200,000**, while the clean-gas delivery rate would fall somewhat to **1.5 mmscf/d**, and electricity consumption would decrease to about **250 kW** per day.
2. A **4.0 mmscf/d** LFG producing site will yield about **2.2 mmscf/d** of pipeline quality gas with a turnkey cost of approximately **\$4,500,000**. The production facility would require a daily expenditure of approximately **1,250 kW** of electricity if it did not use some of the LFG for running the process. The capital cost of the gas-drive would rise to approximately **\$4,950,000** and the clean-gas delivery rate would fall somewhat to **2.0 mmscf/d**, while electricity consumption would decrease to about **325 kW** per day.
3. An **8.0 mmscf/d** LFG producing site will yield about **4.4 mmscf/d** of pipeline quality gas with a turnkey cost of approximately **\$6,500,000**. The production facility would require a daily expenditure of approximately **2,450 kW** of electricity if it did not use some of the LFG for running the process. The capital cost of the gas-drive would rise to approximately **\$7,000,000** and the clean-gas delivery rate would fall somewhat to **4.0 mmscf/d**, while electricity consumption would decrease to about **725 kW** per day.

Labor costs in all cases would be two operators during a day shift, with the night shift unattended. The larger the facility, the less impact labor costs will have on the total operating costs.

As is evident from the above, the **8.0 mmscf/d** landfill site, yielding **4.4 mmscf/d** of pipeline quality gas, does not require twice as much capital cost to yield twice as much product as a **4.0 mmscf/d** site. Similarly, the cost difference between the 3.0 mmscf/d and 4.0 mmscf/d sites is only \$500,000. The larger facility processes 33% more LFG, but at an incremental extra cost of only 12.5%.

However, few landfill sites produce LFG at the rates of 4.0 to 8.0 mmscf/d, which equals 1.5-billion to 2.9-billion cubic feet per year. Fresh Kills, the second largest landfill site in New York State, is estimated by US EPA of having a potential LFG production rate of **16.6-billion cf/yr**. That translates to approximately **45.48 mmscf/d**, well above the scale of the three examples listed.

New York's next largest landfill (per EPA estimated potential LFG production rates) is the Blydenburg Road facility in Hauppauge, a closed site. It is estimated to have an untapped potential of only **1.8-billion cf/yr** of LFG production. That figure translates to **5.0 mmscf/d**. Of the currently open landfills in New York state, only the Niagara and Fresh Kills sites are "very large", with a potential LFG production rate well in excess of the amounts needed for economic recovery and processing. The following three open sites each have EPA estimated LFG recovery potentials of over **1.0-billion cf/yr**: Seneca Meadows, Al Turi, and the Modern Landfill.

The next tier of NY sites have un-used potential production rates of approximately **700 mmscf/yr**. This figure translates to a daily rate of less than **2.0 mmscf/d**, a production rate that is well below the first (and most expensive) example cited above.

Indeed, we need to be careful about EPA's (or a landfill operator's) projections for estimated annual LFG production rates. Some estimates are overly optimistic because they are based on the volume of gas burned in flares. Flared gas often includes air.

On the other hand, if one wants to see the glass as "half full," we can argue that any site that produces more than **1.0-billion cf/yr** will fit within the general production rate and economic parameters of the first example cited above, because $1,095 \text{ mmscf/yr} = 3.0 \text{ mmscf/d}$.

The following five Maryland landfill sites fit within that range:

1. Brown Station Road, Upper Marlboro, with a potential of **1,506.1 mmscf/yr**;
2. Millersville/Sudley Road, Severn, with a potential of **1,416.2 mmscf/yr**;
3. Oaks, Laytonsville, with a potential of **1,296.1 mmscf/yr**;
4. Quarantine Road, Baltimore, with a potential of **1,115.9 mmscf/yr**;
5. Sandy Hill, Bowie, with a potential of **1,032.5 mmscf/yr**.

It should be noted that all five of these facilities are within the territory of Baltimore Gas and Electric, a local utility that has CNG/LNG production and distribution capabilities. In such a context, the pipeline quality gas produced by the Kryos process can be "wheeled" for dispensed CNG/LNG at off-site locations.

With regard to wastewater treatment plants, New York City's largest facility, Newtown Creek, has an annual digester gas production rate of 615,503,000 cubic feet. DEP estimates that approximately 54% of the digester gas is "used" on-site.

We need to determine if the digester gas is used to heat buildings and/or to generate heat for the optimization of the digester process. We also need to carefully compare the chemical composition of wastewater digester gas (which can be different in significant ways from LFG) and establish the extent to which the Kryosol Process needs to be modified to treat digester gas. For example, the Kryosol Process considers H_2S concentrations of more than 20 to 50 ppm (parts per million) to be troublesome.

The un-used annual digester gas production rate at Newtown Creek is approximately 332,150,000 cubic feet, or only 910,000 cubic feet per day. It may be possible to process the full digester gas production rate of 615,503,000 cubic feet where the waste heat generated in the clean-up process is returned to the digester process.

In any event, the "wasted" digester gas figure (332,150,000 cubic feet) is less than 33% of the daily production rate in the first Kryosol example cited above. At that scale, the challenge is to design a smaller facility, proportioned to the less than **1.0 mmscf/d** digester gas flow rate of a large wastewater treatment plant, but at a cost that is less than \$3,000,000.

If the capital cost cannot be lowered then it needs to be evaluated in terms of the dual "pollution prevention" benefits associated with the non-flaring of the digester gas **and** the replacement of diesel fuel by the use of CNG/LNG that is dispensed in exchange for the pipeline-quality gas that is inserted into the local system at the wastewater treatment plant. The public policy "value" of pollution prevention at the landfill site or wastewater treatment plant and pollution prevention from municipal trucks and buses may, to some extent, offset the capital cost of the LFG/digester gas treatment facility.

If the capital costs cannot be economically justified, even when public policy issues are part of the equation, the municipality or state may choose to "write off" the capital costs (such as by using NYS Environmental Bond Act funds) and evaluate the "economics" of the facility by comparing only the operating costs of the facility with the value of the CNG/LNG (after accounting for compression or liquefaction costs) that is used by the public entities in lieu of diesel and gasoline.

Another approach that should be examined is the production of medium-BTU gas, which can be mixed with high-BTU (pipeline quality) gas at a controlled rate. The capital cost of a medium-BTU gas processing plant will be lower, but the value of the gas will also be lower. Still, the pollution prevention benefits and other public policy considerations may allow the medium-BTU option to be viable at smaller wastewater treatment plants.

Relative to the capital costs and LFG processing rates described above, what is the "value" of the Kryos Process? One way to answer this question is to assume that a **3.0 mmscf/d** (million standard cubic feet per day) LFG producing site will yield about **1.65 mmscf/d** of pipeline quality gas (nearly 12,000 diesel equivalent gallons of CNG) **and** approximately **80 tons** of liquid carbon dioxide.

Such a combined gas clean-up and CO₂ recovery plant will have a total capital cost of approximately **\$6,000,000**. The net annual value of the carbon dioxide could be as much as **\$700,000**. The value of 12,000 diesel equivalent gallons (DGE) of CNG per day, or 4,300,000 DGE per year, at only 50¢ per gallon, is over **\$2,000,000**. Even accounting for operating costs, wheeling cost, and dispensing costs, the combined plant could be "profit-making" to a non-taxed municipal entity within the productive life of the landfill.

Indeed, the economics may allow the public entity to "franchise" the entire vertically integrated LFG-to-CNG/LNG model, thus assuring itself of a fully fueled AFV fleet and a virtually emission-free landfill, with the private sector operator's income coming from a combination of management and operating fees, from the sale of excess CNG/LNG to private fleets, and/or from the carbon dioxide sales.

If properly designed and built, the entire LFG processing plant could be moved to another location after the landfill's production rate drops off.

5.5 SRI International

SRI International is a research entity located in Menlo Park, CA. Pursuant to a DOE Contract (DE-AC21-95MC32665) undertaken between October 1995 and June 1998, SRI International examined techniques for removing nitrogen from methane.

Methane with high nitrogen content, often above 4%, is not suitable for most applications and is thus "left in the ground" or is inserted into pipelines at a very slow rate (thus diluting the nitrogen) or it undergoes "nitrogen rejection" by cryogenic processes, which significantly increase the cost of the gas. Landfill sites that do not carefully manage their gas recovery tend to increase the nitrogen content of the gas.

SRI's research involved the use of a nitrogen selective absorbent. They sought to examine the technical and economic feasibility of N₂ removal by using "complexing agents" that would selectively and reversibly absorb/desorb N₂ from low quality natural gas. SRI sought complexing agents that could absorb (react with) N₂ at high pressures typical of feed gas, and would release N₂ at lower pressures.

SRI's work established that a "nonaqueous complex" can absorb N₂ at high pressures (200-400 psia) and then desorb it at atmospheric pressures. SRI noted that "the complex precipitates out of solution once it is bound to N₂ and re-dissolves in the solution once the N₂ is unbound."

Their economic analysis of nitrogen removal for a feedstock that is 20% nitrogen and 80% methane, at 1000 psia, estimates production costs at 26¢/Mscf in a 75 MMscf/d plant. SRI suggests that those figures will compare favorably to other available nitrogen removal systems. The next step in establishing the viability of this SRI nitrogen rejection process is to design, construct, and operate a high pressure bench scale unit that can treat up to 0.25 Mscf/d of gas. Such a bench scale model would allow SRI to vary key parameters such as gas and liquid flow rates, operating temperatures, gas pressures and inlet nitrogen content. The collected data would be used to design a "scale-up" demonstration model for possible commercial applications.

For further information, contact Dr. Marianne Asaro, Senior Chemist, at SRI International's Chemistry Laboratory, Tel. No. 650-859- 2086, FAX No. 650-859-4321.

6.0 SMALL SCALE LIQUEFACTION TECHNOLOGIES

6.1 Cryenco

Cryenco, Inc., of Denver, Colorado, a subsidiary of Chart Industries, with headquarters in Cleveland, Ohio, is developing two liquefaction technologies for remote or "marginal" gas reserves, including landfill sites and sewage treatment plants.

Cryenco's Linear-Motor-Driven Orifice pulse tube refrigeration (LOPTR) system uses a linear electric motor to power the Orifice Pulse Tube Refrigeration (OPTR) unit. LOPTRs will "have no cold moving parts, no lubricants and no wearing seals or bearings." Capacities of up to 1,000 gallons per day are projected.

Cryenco's Thermoacoustically Driven Orifice Pulse Tube Refrigeration (TADOPTR) system is a natural gas-powered liquefier that has no moving parts. It is projected to have capacities ranging from 500 to 40,000 gallons per day. The basic elements of the TADOPTR are the thermoacoustic driver (TAD), an orifice pulse tube refrigerator (OPTR) and a natural gas burner acting as a power source.

The TAD has four major elements – a "hot heat Exchanger," a "stack," a "cold heat exchanger" and a "resonator." The gas burner provides power to the hot heat exchanger, the stack transfers heat into and out of a "working gas" (helium), and as the "cold" or ambient heat exchanger rejects heat to water, it produces an oscillating pressure wave.

The OPTR, a "variation of the Stirling Refrigeration Cycle, also has four major elements – a "pulse tube," an "orifice/reservoir system," a set of heat exchangers and a "regenerator." Helium "working gas" is expanded and compressed in the pulse tube. The orifice/reservoir produces refrigeration power by establishing the "correct phasing between pressure and mass flow. The regenerator provides thermal isolation between the TAD (driver) and the cold heat exchanger.

Cryenco's TADOPTR program is under development. Phase I of the program has resulted in a 140 gallons per day (Gpd) prototype unit. Phase II will yield a 500 Gpd prototype within approximately 12 months. Phase III will achieve 10,000 Gpd prototype in an additional 12-18 months. Phase IV will seek to achieve 40,000 Gpd or more.

The initial "efficiency" of the 500 Gpd system is projected at 70% LNG, where 30% of the feedstock is burned as an energy source. The 10,000 Gpd system will aim to achieve 80% efficiency, using only 20% of the feedstock as an energy source. Ultimately, Cryenco hopes to achieve efficiencies "equal to large scale liquefiers."

In the interim, the TADOPTR may still be competitive as a vehicle fuel producer if it can produce LNG so that 1.7 (or 2 gallons), pre-tax, are less expensive than 1 gallon of pre-tax diesel. When applied to landfill gas or digester gas from municipal facilities, the economics will depend not so much on the "efficiency" of the on-site liquefaction system, but on the cost of cleaning the feedstock. Because LFG and digester gas can be considered virtually "free," it can absorb approximately 17¢ to 20¢ in clean-up costs

in lieu of the "commodity" and "transportation" costs of pipeline gas. Thus if the TADOPTTR can use 30% of the LFG output as low-BTU fuel to run its burners, and the remaining 70% "very clean methane" to produce LNG, and if the collection and clean-up of the LFG costs less than, say 17¢ per gallon of LNG product, it may produce lower cost LNG than pipeline-fed systems.

If, however, the clean-up costs are higher, then the TADOPTTR and indeed any other small scale liquefier, will only be competitive if it can achieve efficiencies equal to large scale liquefiers. In the final analysis no matter how efficient the LNG plant, the dispensed price of 1.7 gallons of LNG (on a BTU equivalent basis), or more like 2.0 gallons of LNG (on a per mile traveled basis), must be less costly than 1 gallon of diesel. The premise (and hope) of this study is to show that LFG and digester gas are cost-effective feed stocks that should have a virtually free commodity cost, a very low transportation cost and a "reasonable" clean-up cost.

The TADOPTTR's gas burner can operate with partially cleaned (low BTU) gas. However, certain compounds such as H_2S , may damage the burner/hot heat exchanger and should be removed. But other compounds, such as CO_2 , may not cause a problem as long as the heat content (BTU) of the burned gas is adequate. Another consideration, regarding low-BTU gas is its emission characteristics. One can assume that partially cleaned gas will yield less emissions than untreated flared LFG.

Prior to feeding LFG to the liquefaction side of the TADOPTTR, it must be free of CO_2 and water. For the purposes of this report, the TADOPTTR requires the CO_2 content of the feed gas (the part that is not used to operate the burner), to be less than 50 ppm, and the water content to be less than 0.1 ppm. The inlet pressure for the methane to be liquefied should not be excessive. Pressures up to 500 psi are acceptable and may serve to improve the system's efficiency, if planned for. This is a consideration because clean-up systems often include steps that pressurize the LFG. With regard to the temperature of the feed gas, 100 degrees Fahrenheit, or lower is fine. However, the colder the inlet gas, the more efficient the system.

The size of the above described TADOPTTR will allow it to be skid- or trailer-mounted, and will allow it to be "grouped" in multiple units if needed.

6.2 CryoFuel Systems Inc.

CryoFuel Systems, Inc. (CFS) is a designer and manufacturer of proprietary "advanced gaseous fuel processing systems." CFS is located in Monroe, Washington.

In a letter dated December 1, 1998, to Vandor + Vandor, and in follow up correspondence dated December 16, 1998, January 25, 1999, and March 3, 1999, CFS outlined the development of a small scale liquefaction system that has advanced from the "detailed engineering phase of development to the manufacturing stage." They intend to design and manufacture purification and liquefaction plants that will efficiently and economically produce 500 to 2,500 diesel gallon equivalents (DGE/d) (or 850 to 4,250 LNG gallons per day) from a wide range of gas sources such as pipeline gas, landfill gas and stranded/remote gas wells, as well as gases from

anaerobic digesters at wastewater treatment plants. A 50 DGE/d "bench-top" LNG unit will be assembled and tested in early 1999. CFS' system will consist of modular, skid mounted, autonomous units designed to fit within the dimensions of standard ISO shipping containers.

CFS' design contains all components of the "cleaning," de-watering and liquefaction steps that are necessary to produce up to 99% pure methane from a variety of feed stock. CFS is "in the process of doing a technology demonstration project to convert landfill gas (LFG) to LNG at a modern landfill near Victoria, BC" where CFS will be testing a 500 DGE/d system. CFS believes that their product can fit a "niche" of landfills that produce between 0.25 and 3.0 MMscf/d of LFG. The lower limit (approximately 500 DGE/d) may be economic for on-site dispensing of LNG, such as for a small fleet of refuse haulers. For off-site dispensing the cost of additional storage and transportation costs suggest that the minimum production rate is 1,000 DGE/d.

The company recognizes that, with pipeline gas as feedstock, the resultant LNG is "not competitive with diesel in most jurisdictions." However, they believe that non-standard gas sources, such as landfill sites, sewage treatment plants and stranded gas reserves can yield competitively priced LNG. Furthermore, they believe that "in the case of a landfill, the level of revenue generated can frequently exceed that available from conversion of [low BTU] gas into electricity."

In short, CFS argues that LNG is a "higher value product than electricity" and that their proprietary system can transform low-value landfill and anaerobic digester gas into "high-value" LNG without incurring excessive capital and operating costs.

The most significant aspect of the CFS system seems to be its ability to remove sulfur compounds found in sewage treatment digester gas, and nitrogen and "volatile organic compounds" (VOCs) found at landfill sites, as well as carbon dioxide and water. This suggests that CFS' design does not require it to be preceded by clean-up systems, such as those discussed in §5 of this report. If this unique aspect of the CFS system can be successfully demonstrated and proves to be economically viable, the CFS system would then be a viable alternative for landfill and wastewater treatment plants that are not near existing natural gas pipelines.

In the CFS process, LFG undergoes three stages of purification. The first two stages are relatively conventional pre-processing techniques for moisture removal, thermal swing adsorption (TSA) of contaminants, and filtration to remove particulates and trace quantities of noxious chemicals. Particulates and trace chemicals are eliminated by burning at high temperature in the NG-fueled CFS engine. Since the LFG may contain O₂, it will require an additional purification stage after the TSA stage to insure that no oxygen is dissolved in the LNG. Such oxygen removal units are common and commercially available.

The purification and liquefaction of the gas occur in a single step rather than two distinct steps. This serves to decrease operating and capital costs relative to competing processes. CFS' system requires a water wash state, activated carbon

adsorption stage, and compression to a relatively low pressure before entering the cold box. The decrease in the number of stages increases the final product yield and decreases the "footprint" of the system.

A stream of dry N_2 , CH_4 , and CO_2 is the product of the first two stages of purification. This stream is supplied into the cryogenic purifier/liquefier unit that separates CO_2 and CH_4 . (The production, storage and distribution of commercial grade CO_2 can become a valuable by-product of the CFS process for a very low incremental cost.) If the level of N_2 in the resultant LNG is greater than desired, a proprietary N_2 rejection facility can be added at a small incremental cost.

The CFS unit creates no new emissions and can use the C_3+ components of the feed gas for a fuel supplement for high overall energy efficiency. One of the unique features of the CFS system is that water vapor condensed from the feed LFG can be treated in several ways. In the preferred approach, it is aspirated into the engine driving the compressor for complete destruction with no liquid emissions. Alternatively, it can be returned either to the leachates system or to the landfill.

Trace quantities of sulfur compounds and VOCs are removed by the TSA beds unless the concentrations are very high. Upon regeneration of the beds, these compounds are routed to the engine as supplemental fuel where they are combusted at higher temperature and longer residence time as compared to a typical landfill flare. If the engine exhaust emissions become a problem, catalysts on the engine may be required. If the concentration of sulfur compounds becomes too high, a separate disposal process will be required. CFS suggests that digester gas with concentrations of 39.2 ppm of H_2S and 0.85 ppm of mercaptans (as found in the Yonkers, NY, wastewater digester gas stream), is within the design parameter of the TSA beds.

The activated carbon/zeolite adsorbents used in the TSA beds have been selected for long life over many regenerative cycles. However, they may require replacement after several years of operation. The costs for purchasing new adsorbent, and disposing of spent adsorbent are quite small.

CFS' processing system is designed for automatic 24-hour, unmanned operation and include a full complement of sensors, including ones in the gas stream to and from the TSA beds. The control system will adjust the timing between regeneration of the TSA beds so as to ensure high quality feed to the liquefier under variable LFG conditions.

Depending on the CH_4 content of **pipeline gas**, approximately 10% to 15% of the feed gas is used as a fuel in the engine driving compressor and small generator. The feedstock for the engine can come at several points in the process -- directly from the pipeline, from the regenerating TSA purifier, and from boil-off at the LNG storage tanks and at the LNG dispenser / transfer point. Waste heat from the engine is used to regenerate the TSA beds for increased overall efficiency.

The extra equipment required for pre-purification of **LFG** requires relatively small amounts of extra energy. To maximize efficiency, cleaned feed gas is used for this

purpose. As a result, LFG process efficiency is only marginally lower, requiring approximately 18% to 21% of the feed LFG as fuel for the engine. Low BTU gas that flows out of the initial purification stages can be fed to the engine, but CFS prefers to use the higher quality gas that is available after CO₂ removal. A key feature of CFS' LFG technology is that no external utilities are required for its operation. CFS believes that in areas where a market for "commercial grade" CO₂ is available, the installation of an additional compressor and a storage tank would allow their system to yield commercial grade CO₂, in addition to the LNG stream.

CFS is currently (February 1999) moving from the detailed engineering phase to the manufacturing phase. The first steps to be taken at a CFS' newly leased manufacturing site in Monroe, WA, is to assemble a bench top unit. They expect to begin testing by March of 1999. Initial testing will use pipeline quality methane as a demonstration that the technology is reliable, efficient and can be scaled to commercial size. With regard to LFG processing, CFS is confident of success because the various components of the LFG pre-purification steps are conventional, off-the-shelf items that do not require demonstrations.

Still, the landfill gas to LNG system has several design modifications from the bench top unit. Thus, CFS is seeking a paid contract as mechanism to build and demonstrate a unit that processes LFG. In the context of this study, the ideal demonstration site would be a Maryland landfill of significant size, that is not near an existing natural gas pipeline and thus allows for the demonstration of on-site LNG production where "commodity trading" or "wheeling", as discussed above, is not possible.

The CFS technology can be scaled to LFG flow rates of as low as 0.3 MMscf/d to more than 3.0 MMscf/d. This suggests that many small to medium sized landfills and wastewater treatment plants which are not viable as electricity generating sites or are not appropriate for those LFG clean-up systems that require large gas-flow rates, may be suitable for small scale LNG production. CFS' modular design allows it to respond to changing gas flow rates over the life of each landfill site.

An optimum demonstration for a 1,000 MMscf/year landfill would entail a set of CFS processing units with an LNG production capacity of 8,440 DGE/day or approximately 14,350 LNG gallons per day. CFS would place one 2,500 DGE/d liquefaction units at such a site, followed by a second and a third unit as the market for LNG developed. The final configuration of three units would provide some level of redundancy and maintenance flexibility. As the LFG flow-rate waned, toward the end of the landfill's productive life, one or two modules could be removed and used at other sites.

Such a demonstration would require a local (or nearby) fleet of heavy-duty trucks, such as the trash-haulers that routinely arrive and depart from the landfill, and perhaps some additional local vehicles, such as a portion of the nearest school bus fleet. The demonstration would start with limited on-site LNG storage capacity of, say 10,000 gallons, as the single storage/dispenser for the test fleet. As the LNG customer base grew, off-site LNG storage/dispensers would be fed by a 10,000 gallon cryogenic tractor-trailer.

6.3 Cost Estimates of CryoFuel Systems' LNG Plant

CFS will price its 1000 DGE/d LFG-to-LNG system at approximately \$652,000, including on-site LNG fueling and three days of on-site LNG storage capacity. Over the expected 20 year life span of the CFS LFG-to-LNG equipment, the life-cycle cost of fuel from the combined purification and liquefaction plant, sized for 1000 DGE/day, is expected to yield LNG at an approximate cost of 55¢/DGE (1.7 gallons) of pre-tax LNG. The following figures make up the 55¢:

1. Capital Cost	27¢
2. Feedstock	07¢
3. Operating Cost	18¢
4. Service Contract	<u>03¢</u>
	55¢

The estimated life cycle costs are based on amortization of capital costs over 20 years at 8% p.a. Feedstock price to the landfill was assumed to be 50¢/Mscf (per thousand standard cubic feet.)

If a lower life span is used in the calculations, say 15 years, the delivered cost of LNG from LFG will increase to 57¢/DGE (diesel equivalent gallons). On the other hand, if the landfill is owned and operated by a municipality or other government entity, for its own AFV program, the cost of feedstock can be zero, thus reducing the 15 year life span cost to 50¢ per DGE of LNG. If a larger plant size is selected the economics of scale will reduce the life cycle costs of the LNG somewhat. Some additional cost related to transporting and dispensing of the LNG at off-site locations may need to be added to the final cost of the product. At the same time, CFS is confident that where markets exist within economic transport range, industrial grade CO₂ can be produced at a small incremental cost. The added revenue from the CO₂ can reduce the cost of the LNG.

At 50¢ to 60¢ for 1.7 gallons of LNG, and assuming that the AFV fleet that is served by the CFS plant can achieve the same fuel economy on 1.7 LNG gallons as it normally achieves on one gallon of diesel, the economics of the CFS process look promising, particularly if diesel prices rise and the LFG-to-LNG process costs stay stable.

However, if heavy-duty AFV trucks require 2.0 gallons of LNG to equal the miles traveled with one gallon of diesel, then the DEG price of the CFS LNG rises from a low of 50¢ to nearly 59¢, and the higher 60¢ estimate rises to nearly 71¢. Those figures will in most markets be higher than the pre-taxed cost of diesel.

Thus, to the extent that the final fuel costs are used to measure the comprehensive economic viability of the CFS system, it first needs to be demonstrated at a public landfill, where the LFG can be priced at zero. In addition, CFS' LFG-to-LNG process needs to be linked to an efficiently distribution system that feeds a public AFV fleet, and the LNG needs to be used by the most efficient AFVs in the market. CFS believes that it can deliver an LNG dispenser, that may cost up to \$90,000 from other vendors,

for approximately \$50,000. They suggest that leasing of LNG transport trailers may be a better choice than outright purchase when a local LNG network is just starting out.

With regard to the last point, it may be necessary to include a significant number of light-duty vehicles in the test fleet, because light-duty AFVs tend to attain fuel efficiency that is similar to their gasoline counterparts. In reality, federal AFV mandates are aimed primarily at light-duty vehicles, and most public fleets (and utility fleets) are made up of a preponderance of light- and medium-duty vehicles. On the other hand, as discussed above, the pollution prevention aspects of AFVs is greater in heavy-duty than light-duty fleets. For a relatively small incremental cost, CFS' units can also produce CNG, allowing a mixed fleet of light- and heavy-duty vehicles to rely on CNG and LNG from the same unit.

The CFS system, by including clean-up and liquefaction in one package, and by adding CO₂ production, may well be able to achieve, in a single package, the "double" pollution prevention goals of landfill (and/or wastewater digester gas) clean-up, and the increased use of AFVs in public fleets. To the extent that the CO₂ product stream is used to replace environmentally unfriendly products, (such as "perc" used in dry cleaning of clothes), the CFS systems can have a third pollution prevention aspect.

If the technology and "efficiency" of the CFS system can be demonstrated it will catapult CFS to the forefront of LFG-to-LNG technology, creating an economically and environmentally sound approach for the re-use of landfill and wastewater digester gas that is produced at sites that are not adjacent to natural gas pipelines.

6.4 Institute of Gas Technology

The Institute of Gas Technology (IGT), located near Chicago, is currently working on developing a small scale LNG liquefaction system. Their work is funded, in part, by Brookhaven National Laboratory. As of early-February, 1999, IGT was preparing to test a 100 gallon per day LNG liquefier. (The tests were scheduled for mid-February.)

IGT's device will first utilize pure methane as a "feedstock." The tests will concentrate on the IGT's ability to integrate the various elements of their liquefier and to establish the "leak proof" continuity of the process. This is a limited set of goals that excludes, for the moment, the issues associated with pipeline quality gas (which is not pure methane) and with LFG or wastewater digester gas, both of which require significant clean-up steps prior to liquefaction. The cost and efficiency of IGT's small scale liquefier has not yet been established.

IGT hopes to address these issues, and to raise the capacity of the system to 500 gallons per day, as part of its Phase II work. Phase II will include a clean-up system that can tolerate raw LFG as a feedstock. IGT recognizes that if its small scale liquefier is not as efficient as some very large "peak shaving" plants, then it will need to carve out a special niche in the LNG market. That niche is likely to be limited to LFG and to wastewater digester gas sources where the value / price of the feedstock is relatively low and thus allows a lower efficiency, skid mounted liquefier to produce relatively small amounts of LNG in a cost-effective manner.

Phase II of IGT's work will test the efficiency of various refrigerant systems. They hope to complete their Phase I work by September, 1999, to be followed by Phase II. IGT does not anticipate that their design and engineering process will result in proprietary solutions, with the possible exception of the "control systems."

6.5 Liberty Fuels

Liberty Fuels, Inc., (LFI) based in Santa Cruz California, has begun marketing the "Liberty Station 2000 Liquefinery Vehicle Refueling System."

In its brochure, LFI makes the point that 55 diesel equivalent gallons of LNG can be stored in a 25" by 63" container weighing 639 pounds, fully fueled. This compares favorably to a 55 gallon diesel tank that measures 20" by 50" and weighs, 551 pounds fully loaded. More significantly, the equivalent CNG configuration, also at 55 diesel gallon equivalent, would require 11 cylinders, each 13.5" by 72" and weighing a total of 2,535 pounds, fully fueled. In short, LFI argues that LNG is the alternative fuel of choice when vehicle range and the weight of the fuel system are important considerations. The brochure also notes that LNG is significantly cleaner than gasoline and diesel fuel.

However, the most significant claim made by LFI is that its system "offers the lowest fuel price available to the fleet operator." That claim is based on the following price components (in \$):

Amortized Station Capital Costs	.19
Pipeline Natural Gas (commodity)	.20
Pipeline Delivery (transportation)	.10
<u>Station Maintenance (per contract with LFI)</u>	<u>.05</u>
Total Fuel Cost	.54

The station cost price is quoted at \$650,000 and is assumed to be financed at 8% for 10 years. The \$0.20 pipeline gas price is based on 1 therm (100 standard cubic feet or 100,000 BTU) of "product" at an annual average price of \$0.20. Similarly, the transportation cost assumes that the local utility will charge \$0.10 per therm. Taxes are not included in the above.

The Liberty Station 2000 is designed to produce and store up to 1,500 gallons of LNG per day, at a pressure of 125 pounds per square inch. The station can dispense up to 30 gallons of LNG per minute and 250 standard cubic feet (scf) per minute of CNG, for light duty vehicles. (The 250 scf rate is equivalent to approximately 2 gasoline-gallon-equivalents per minute.)

As of mid-February, 1999, the following questions were not responded to by Liberty Fuels Inc.:

- How many gallons of LNG will be produced from 1 therm of gas? Does the \$0.54 estimated cost reflect the cost of one gallon of LNG, or does it reflect the cost of 1.7 gallons of LNG -- the diesel equivalent amount?
- Can the LS 2000 run on natural gas, and if so, how much of each therm is used to run the liquefier?
- Can the system operate on non-pipeline gas, such as wet landfill gas (48% to 50% methane, 48% CO₂ and 1% to 4% nitrogen and VOCs...) Or sewage treatment gas with sulfur content?
- If the inlet gas needs a pre-cleaning process, what is the "extreme" that the LS 2000 will tolerate regarding water, CO₂, nitrogen,?
- Does the LS 2000 keep track of the natural gas "inflow" -- in therms or scf? -- as well as the LNG / CNG "outflow"?
- Does the 125 psi LNG favor MVE's high pressure tanks, or is it "neutral" with regard to the final pressure in the fuel tank, allowing the fleet operator to use Snyder's lower pressure tanks?
- Does the calibration on the dispenser account for any gas that may return to the LNG tank within the dispenser? In other words, does it accurately count the total gallons that end up in the customer's fuel tank?

7.0 FINDINGS

Given the LFG reclamation projects cited above, and the estimated economics of the various clean-up systems, it seems that in order to lower the price of LFG-to-pipeline quality gas, the LFG or wastewater production facility has to be as large as possible, with a large gas flow rate. The extra step of producing CNG or LNG, at the landfill or wastewater treatment site, adds capital and operating costs and decreases the overall efficiency of the LFG-to-CNG/LNG process.

CNG's "bulk" and lack of transportability, argues against large on-site CNG production systems unless a very large fleet is close to the landfill site. The likelihood of matching large landfills with large CNG fleets is remote because large fleets tend to be concentrated in urban areas whereas landfills tend to be located outside of cities.

Given the dearth of fully tested, commercially available small scale liquefiers, and given the reductions in efficiency as LNG plants are down-sized, we sought additional ways to produce LNG from landfill and wastewater treatment sites.

The following five alternatives could be looked at:

- 1) "Cleaned" LFG ("pipeline quality") could be transported by adjacent pipelines to off-site CNG dispensers operated by a large fleet (or to several fleets). Fresh Kills in Staten Island could be an excellent model.
- 2) Small scale LNG production at landfill sites could be examined further, as competing technologies, such as the CryoFuel system, come to the market. This approach may hold promise for smaller landfills and wastewater treatment plants, especially those not adjacent to natural gas pipelines, such as in the eastern parts of Maryland.
- 3) Pipeline quality gas from landfills and wastewater treatment plants could be transported by adjacent pipelines to existing LNG peak shaving plants as a "commodity" ("wheeling") that is exchanged for LNG produced at existing, underutilized, highly efficient, amortized facilities. This approach connects, via an existing pipeline infrastructure, the most efficient large-scale LFG cleaning technologies with the most efficient large-scale LNG production centers. Long Island's Holtsville LNG plant and Maryland's BG&E LNG plant in Baltimore could be two models for the LNG end of the chain.
- 4) Pipeline quality gas from landfills and wastewater treatment plants could be exchanged for LNG produced at newly built "let-down cycle" LNG plants located on valves between high- and low-pressure pipelines. Various upstate New York locations, including several "economic development zones", could benefit from this approach. The let-down cycle LNG plant can be an important option in California where the demand for LNG as a vehicle fuel and for other uses could be significant.
- 5) Pipeline quality gas from landfills could be exchanged for LNG produced at upgraded gas processing plants that have an investment in large and efficient gas processing technology that includes cryogenic components. This model may be viable in the mid- and south-west.

7.1 Pipeline Insertion of Cleaned LFG

The first option avoids the costs of compressing, storing and dispensing of CNG on-site. It does not need to link the economic viability of cleaned landfill gas to the proximity of a large CNG fleet. If the New York State legislature does not allow the existing LNG moratorium to lapse, it is the only option available in the state.

In the Maryland context, this option has two drawbacks. First, the eastern shore of Maryland does not have a natural gas pipeline network. Thus, for those landfills not near a pipeline, the only CNG option is on-site dispensing at the landfill, similar to the Puente Hills model, discussed above.

Second, Baltimore Gas & Electric, the local gas distribution company, injects "propane air" into some portions of its pipeline as a peak shaving technique. CNG compressors located within that sector need to be shut down during propane-air-injection days, or risk expensive damage. For that reason, CNG is not a dependable alternative fuel for vehicles in some of BG&E's service territory. Thus, in the Maryland context, options 2, 3 and 4 offer more potential. Option 5 will need to be evaluated after a list of suitable gas processing plants is developed.

7.2 Small Scale, On-site Liquefaction

The second option, on-site small scale liquefaction, may be promising in contexts where the landfill site is not near a pipeline and where the "commodity trading" model (known in the industry as "wheeling") is not viable, or where there is an absence of nearby liquefaction facilities. In those contexts, on-site LNG production may be the only way to produce a "transportable" version of clean LFG. The transportation costs of LNG is reasonable for distances of less than 300 miles. Any single LNG source can supply a large and diverse customer base that is not necessarily adjacent to the landfill site.

On the other hand, given the difficult economics of LFG to CNG, it is hard to imagine that an additional process, small scale liquefaction, can be achieved at low enough capital and operating costs to produce a competitively priced gallon of LNG. Only the CryoFuel process, discussed above, claims to be able to clean and liquefy LNG in a cost-effective way. The CFS system needs to be demonstrated in a variety of context.

As we evaluate any comprehensive LFG-to-LNG system, we need to remember that on a BTU (heat value) basis, 1.7 gallons of LNG is equal to a gallon of diesel. However, in practical applications, such as in urban delivery trucks, or in "stop-and-go" busses or refuse haulers, the LNG demanded by the OEM LNG engine may be closer to 2 gallons of LNG for each unit of distance traveled by an equivalent vehicle that uses 1 gallon of diesel.

Thus, if fully taxed diesel is available at \$1.00, including capital and operating costs of the diesel dispensing station, then 1.7 (or 2) gallons of LNG will need to sell for less than \$0.50, fully taxed, and even less than that if the fleet operator is to recover the extra cost of the LNG powered vehicle. Those figures will be very difficult to achieve,

even if the most efficient (largest) LNG plant is the source. Still, for public fleets, fueled by LNG produced at public landfills, the CryoFuel model, and perhaps others, might prove economical.

7.3 Trading for Existing Peak Shaving LNG.

The third, fourth and fifth options may prove the most economical. In the third model, LNG would be produced at an existing facility that has been paid for and is operating at an extremely low capacity -- perhaps only 60 days per year. According to a report by Roy Adkins, "in 1990 there were 55 LNG facilities operated by 47 utility companies. A similar 1992 report by Booze-Allen claims that there are more than 60 "peak shaving" facilities operated by more than 50 utilities in the nation. In addition to "peak shaving" plants operated by utilities, there are many liquefaction plants owned and operated by industrial gas producers.

In this "trading" model, the cost of the "feed stock" is the price of "raw" LFG, cleaned to pipeline quality, compressed to adjacent pipeline pressures and "wheeled" to relatively close, regional peak shaving plants.

One estimate of the cost of producing LNG at BG&E's "turbo-expander" process peak shaving plant is 10¢ per gallon of LNG. This facility is relatively small, with a processing capacity of only 2.75 Mmcfd. It is likely that at larger facilities, such as the 10.00 Mmcfd plants operated by Atlanta Gas Light, Georgia and Peoples Gas Light, Illinois, the cost of producing LNG is less than 10¢.

7.4 Trading for LNG From New Let-Down Cycle Plants.

The fourth model relies on a newly constructed high-efficiency "let-down cycle" (or turbo expander) LNG plant. If a regional LNG demand of approximately 24,000 gallons per day can be induced, a let-down cycle LNG plant could be economical. That volume of LNG would require a customer base that is larger than most local AFV fleets. Possible scenarios in New York, might include the establishment of a peak shaving facility in the northern or western part of the state, which might also feed local industries that are not adjacent to a pipeline, as well as a regional AFV market. Such a plant could "trade" its product for pipeline quality methane produced at various local landfill and wastewater treatment sites.

The let-down cycle uses the compression energy in pipeline gas that is transported at pressures between 200 to 600 psi. Normally, the high pressure is reduced (let-down) through a valve at a gate station for municipal distribution at 20 to 30 psig. The let-down cycle LNG production process utilizes one or more expansion turbines which recover the compression energy in the gas and convert it to refrigeration which serves to liquefy the gas.

As discussed above, Brooklyn Union's existing LNG plant in Greenpoint, Brooklyn, is a wonderfully efficient let-down cycle facility.

Only small quantities of electricity are required for the operation of fans, pumps and various controls. The economics of let-down plants can be very attractive due to the

very low operating costs. The ideal location for such a plant is on a valve located on a high pressure gas line, within a low-rise industrial land-use context -- and within a market area that not only has a need for LNG as a substitute for diesel but can use LNG, beyond the pipeline network, as a substitute for other fuels in non-vehicular applications.

We assume that there are dozens of let-down valves in states that have low-pressure urban distribution systems, including New York, Maryland and California. We also assume that most state-sanctioned "economic development zones" and most federal Empowerment Zones contain, or are adjacent to, let-down valves that may be appropriate for LNG production.

The construction of such plants, creating low-cost energy that can substitute for diesel in urban vehicles, and creating low-cost electricity, and/or low cost refrigeration for food processing plants, may be an option in urban economic development areas.

It is likely that three important elements of low-cost LNG production -- landfill sites and/or wastewater treatment plants, let-down valves on high pressure pipelines, and existing state and federal economic development zones -- can be found in a number of locations in the North-East. The basic requirements for LNG's use as an alternative fuel are likely to be found in urban economic development zones. The pollution prevention aspects of such a comprehensive approach would yield significant air quality benefits in precisely those areas that tend to be in "non- attainment areas."

However, if a let down cycle LNG plant is not a viable option, the development of CNG dispensers at pressure reduction "gate stations" is a proven technology that will reduce the compression costs of CNG at the dispenser.

7.5 The Cost of a Small Liquefaction Plant

A 1992 study for Houston Metro, by Booz-Allen & Hamilton Inc., was based in large measure on the work of Roy Adkins referred to above. In the Booz-Allen report, titled "Natural Gas Liquefaction Costs and Implementation Issues," a proposed 36,000 gallon per day LNG plant was analyzed.

Approximately 500 buses would use nearly 34,000 gallons of LNG per day, assuming a daily diesel fuel consumption per bus of 45 gallons. The Booz-Allen study assumed 1.5 gallons of LNG will equal one gallon of diesel. In reality the ratio of LNG required to displace diesel will be more like 1.7 or perhaps even 2.0 gallons. Still, a 36,000 gallon LNG plant needs nearly 500 buses as a steady customer if its product is to be fully utilized. The size of the on-site LNG storage facility (perhaps 50% of the total project's cost) would be determined by the need for fuel reserves and other factors.

Booze-Allen assumed a seven day fuel reserve of 252,000 LNG gallons, which was estimated to cost approximately \$500,000. A "line-tapping" fee of approximately \$100,000 to \$200,000 will need to be included in the total estimated costs. Other costs will include the \$4,000,000 liquefaction equipment, the \$800,000 installation of the

equipment, \$250,000 in miscellaneous consulting services, and \$350,000 for a tanker loading docks and fuel transfer equipment.

Booze-Allen's total estimated cost of the 36,000 gallons per day LNG plant was **\$6,100,000**. (Booze-Allen relied on Adkins' work and on information provided by Kryopack Inc. and Process Systems International.) The annual operating cost of the plant, including labor, maintenance, insurance, utilities, and natural gas costs for operating the plant, were estimated at \$536,403.

Additional costs will include the capital and operating costs of the LNG tractor trailer. A cryogenic trailer with a 12,500 gallon capacity (able to transport approximately 11,000 gallons of LNG) is estimate to cost \$200,000. The tractor to pull it will cost \$70,000. The total cost of the rig at \$270,000 is amortized over the 15 year life of the tractor at an annual amortized capital cost of \$27,000, or 36¢ per mile.

The total operating cost of the rig yields an estimated transportation cost of the LNG of \$1.33 per mile. At a delivery range of 150 miles, round trip, and only 10,000 gallons of LNG per load, the transportation cost of each gallon of LNG is 2¢. (Booze-Allen relied on information provided by Transgas Inc. of Lowell, Massachusetts.)

The purchase of LNG trailers, which would be moved by a "common carrier," is a more expensive solution that Booze-Allen estimates would raise the transportation cost to 3¢ per gallon.

If LNG producer does not purchase any transportation equipment, but relies on the services of a cryogenic liquid carrier (such as LP Trucking in New York) that would assume all of the capital and operating costs of moving the LNG, the transportation cost would rise to just over 5¢ per gallon.

7.6 The Cost of LNG

The Booze-Allen report concludes that the cost of LNG will depend on the following:

- efficiency of the LNG plant and its full utilization,
- the price of natural gas,
- gas transmission costs,
- plant operating costs,
- the location of the LNG plant relative to the end-user (trucking costs), and
- capital equipment and facilities costs.

In a best case scenario the plant should operate at 90% capacity. The average price of natural gas in 1990 was \$1.71 per thousand cubic feet (MCF). This figure, as it changes over time, offers local publicly owned landfills the opportunity to "compete" with national gas price trends.

The transportation cost of gas in a context such as Houston, which is near the wellhead source can be assumed at 10¢ to 20¢ per MCF. [For gas produced at nearby

landfills and wastewater treatment plants the lower number seems reasonable.] The plant operating cost were estimated above.

As discussed above, the transportation costs of the LNG ranged from a low of 2¢ to a high of 5¢ per gallon. Assuming that the LNG producing entity is not interested in operating LNG transportation equipment, the 5¢ figure is most realistic.

Booze-Allen adjusted the capital costs plus and minus 15% for high and low cost scenarios and assumed a 20 year useful life of the LNG plant, an amortization rate of 8%, as well as a "loss" of 2% of total gas flow.

The total estimated cost of a Diesel Equivalent Gallon (DEG) of LNG, based on variations of the above, was between 41¢ and 56¢ per gallon. (Those figures would fall to between 37¢ to 52¢ for a 108,000 gallon per day plant.)

However, as discussed elsewhere in this report for BNL, it is important to define DEG on actual LNG consumption in the field. If the reality is 2.0 LNG gallons equals 1 gallon of diesel, and the Booze-Allen report assumed only 1.5 LNG gallons, then their final price per DEG needs to be adjusted upward to a DEG price range between 51¢ to 60¢.

In addition to the uncertainty of what is an actual DEG for a bus or a truck in an urban driving pattern, the Booze-Allen study is silent on the capital and operating cost of the LNG storage and dispensing facility at the AFV fueling station. We can assume that it will be higher than a similar diesel dispensing facility and that those extra costs must be attached to the final LNG price per DEG.

On the positive side relative to this study for BNL, Booze-Allen concludes the following:

The price of feedstock gas is the most critical element affecting total costs - comprising 50 percent of the LNG cost per gallon...

"Wheeled" gas from a public landfill or wastewater treatment plant, at a feedstock "cost" that consists mostly of capital and operating cost for the clean-up technology, and very low (or zero) cost for the LFG, could yield LNG with a final dispensed cost lower than diesel.

7.7 Trading for LNG From Upgraded Gas Processing Plants

This option assumes that numerous existing gas processing plants throughout the country have gas processing equipment that provide de-watering, clean-up and gas separation functions. Often the equipment involves large and efficient compressors and cold boxes. Such plants can be upgraded to produce LNG at a cost that should be substantially less than the cost of a new LNG plant. The ideal location would be near an urban market that could provide a significant LNG demand for vehicles. In addition, other local customers, such as a coal- or oil-burning electric plant that seeks to burn clean LNG, will need to be found so that a steady long-term market for the LNG output of the plant can be assured.

A nearby landfill site or wastewater treatment plant could "wheel" pipeline quality gas to the upgraded gas processing plant. The lower cost "wheeled" gas combined with the lower capital cost and high efficiency of the upgraded gas processing plant may yield an LNG stream that can compete with other fuels.

7.8 Liquid Carbon Dioxide

The LFG clean-up systems reviewed above, as well as the CryoFuel Liquefaction system, can also produce commercial grade liquid CO₂. While the CO₂ can be "food grade," there is a sense in the industry that most wholesalers will not purchase CO₂ for food use that was generated at landfill sites and wastewater treatment plants. Still, a market may exist for non-food CO₂. Non-food uses may include replacing toxic solvents used in industrial processes, replacing "perc" in the dry cleaning business, and for use in greenhouses as a plant growth enhancer. In each example, clean, liquid CO₂ would replace a toxic and/or polluting product.

The economics of CO₂ production, as a byproduct of LFG look promising. For example, the Kryosol LFG system that processes 4.0 MMscf/d could be upgraded to also produce pure CO₂ for an incremental extra cost of approximately \$2,000,000. Such an upgrade could produce more than 100 tons of CO₂ per day, with an annual revenue stream of approximately \$1,500,000 for CO₂ valued at approximately \$40 per ton.

The annual operating cost of such a facility, including electricity, labor, chemicals, maintenance... would approximate \$370,000. The "capital charges" (interest and amortization) for the CO₂ processing plant would approximate \$340,000 at an interest rate of 12% over 10 years. Thus the pre-tax cash flow to a private operator would equal approximately \$790,000. A public sector site, built as a turn-key project by a private contractor and operated on a competitively bid lease, could yield a different economic picture because the public sector is free of local, state and federal taxes.

However, as with the production of pipeline quality gas, or the production of LNG, the cost-effective production of commercial grade liquid carbon dioxide requires a "market" (a willing buyer of the product) if the economics are to work. The "marketing" of commercial grade CO₂ from non-traditional sources, in a context of limited gas wholesaling opportunities, may be a more difficult task than the demonstration of the technology.

8.0 IMPEDIMENTS/OPPORTUNITIES

8.1 Impediments in New York State

As of this date, the production, storage, dispensing of and transporting of LNG in New York state is limited to facilities that were in place prior to a "moratorium" on new LNG facilities adopted by the New York Legislature subsequent to a 1971 construction accident in an empty LNG storage tank in Staten Island, NY. That moratorium is the subject of legislation passed in 1997 that requires the New York State Energy Planning Board to study the safety and economic potential of LNG and to issue a report to the State Legislature by December 1998.

The NYS Energy Board's report to the Governor and the Legislature, regarding the existing LNG moratorium, was released on schedule. The report was prepared, per the requirement of Chapter 385 of the laws of 1997, to assess the need for further extension or modification of the State moratorium (imposed in 1978) on the site selection of new LNG facilities and intrastate LNG transportation routes.

The study concluded that there are economic and environmental advantages for allowing the construction of new LNG facilities, that LNG is as safe as other fuels, and that LNG facilities have an excellent safety record that compares favorably with competing fuels. The study also noted that safety concerns are adequately addressed by existing Federal, State and local regulations. The report recommends that the Legislature allow the moratorium statute to lapse (on April 1, 1999) and that Title 17, Article 23 of the NYS Environmental Conservation Law, which imposes regulatory responsibilities on the NYS Department of Environmental Conservation, be repealed.

The report was prepared with the assistance of the "LNG Resource Group," consisting of private- and public-sector representatives of the industry. Vandor + Vandor was a member of the Resource Group. Copies of the "Report on Issues Regarding the Existing New York Liquefied Natural Gas Moratorium" are available from Technical Information Services (NTIS) at (800) 553-6847.

It is unlikely that the NY Legislature will act on the recommendations of the State Energy Board much before April 1, 1999. In the event that the Legislature allows New York's LNG moratorium to lapse, the economic viability of LNG as an alternative fuel in New York will become relevant.

It should be noted that on page S-8 of the Energy Board's report, under the section titled "Recommendations," the following applies to New York City:

The New York City Fire Department requested that the legislative findings or memorandum in support of any legislation ending the moratorium contain the following language:

The City of New York will retain its authority to regulate the storage, transportation, and use of LNG within City limits, including its authority to restrict or prohibit such activities as it determines appropriate in the interest of public safety. Such restrictions and prohibitions could be applied to existing and new LNG transportation routes, as well as to the construction of bulk LNG plants and vehicle fueling station.

Even if the LNG moratorium were allowed to lapse statewide, the City of New York will continue the status quo regarding new LNG facilities, at least for the near future. Given that reality, the production of LNG from NYC landfill sites such as from Fresh Kills, Staten Island, is not likely to occur in the foreseeable future. The fact that the moratorium grew out of a Staten Island incident suggests that even if the Fire Department established specific LNG regulations for New York City, Staten Island may well be the last place the City to permit LNG storage and dispensing facilities.

Other impediments to developing LFG-to-CNG/LNG projects in New York State include the following:

- New York has three LNG producing sites, two of which are located in New York City. There are no LNG facilities in New York north of the Long Island region.
- With the exception of Brooklyn Union, the state's utilities have not aggressively pursued an AFV agenda.
- Outside of the New York City / Long Island region, AFV busses are rare.
- New York's fuel tax structure, especially for alternative fuels, serves as a disincentive for the private sector to acquire AFVs.
- The NYS Public Service Commission, in its natural gas rate setting capacity, has not adequately distinguished between natural gas for AFVs and all other uses.

8.2 Opportunities in New York

Opportunities for developing LFG-to-CNG/LNG projects are fairly good in New York for the following reasons:

- New York has two very large LFG sources, the Fresh Kills Landfill and the Niagara Recycling Facility. Fresh Kills is one of a handful of landfills in the country that produce pipeline quality gas for insertion into the local pipeline network.
- NY has ten other landfill sites (open and closed) that have an EPA estimated potential annual LFG production rate of more than 1-billion cubic feet.
- Many landfills that now gather LFG for electric generation will soon complete their existing contracts to sell electricity. New contracts will not likely be available at an economic rate because the recent value of electricity is too low. Short of flaring the LFG, the only "value-producing" option may be the LFG-to-CNG/LNG model.
- Several ideal landfill sites are government owned, allowing for a comprehensive plan to link public landfills with public AFV fleets.
- New York City's Department of Environmental Protection (NYC DEP) operates the largest wastewater treatment plants in the region. Two plants produce more than 500,000,000 cubic feet of digester gas per year.
- NYC DEP operates a significant number of CNG vehicles. Its CNG fleet may serve as a steady customer base for a steady flow of cleaned digester gas.
- New York City's Department of Transportation (NYC DOT) has been encouraging the purchase of CNG powered taxis. DOT is also pursuing the establishment of "green curbs" in Manhattan, as an incentive for AFV delivery trucks.
- New York State's public sector may be able to use funding from the NY Environmental Bond Act to help finance public AFV fleets.

- New York offers significant tax credits to the private sector for the purchase of AFVs and alternative fuel dispensing equipment.
- The state has an extensive network of environmental advocacy groups that would likely support comprehensive links between waste processing sites and AFVs.
- The New York State Motor Truck Association, which is generally opposed to "mandates," is a supporter of incentives to induce AFV use by the trucking industry.
- Many parts of the state, including its "non-attainment areas," host centrally fueled fleets with predictable duty cycles that fit the parameters of ideal AFV fleets.
- New York City, Long Island and, to a lesser extent, other urban parts of the state, have experience with CNG powered vehicles.
- New York's urban areas are seeking alternatives to "perc," chemical used in dry cleaning. Liquid Carbon Dioxide may be a non-toxic alternative, derived from cleaned LFG and wastewater digester gas.

8.3 Impediments in Maryland

The following impediments for the development of LFG-to-CNG/LNG systems are not structural and can be overcome if public policies are adopted to link pollution prevention at landfills with AFV fleets:

- Maryland does not have a comprehensive plan for increasing the number of public sector AFVs or for inducing private sector AFVs.
- Maryland's AFV experience is limited because it has not relied on LNG as an alternative fuel and because its CNG network is not extensive. Gaps in the state's natural gas pipeline network undermine the growth of CNG fleets.

8.4 Opportunities in Maryland

Maryland offers some significant opportunities for developing LFG-to-CNG/LNG projects, including the following:

- Maryland has five landfill sites that have an EPA estimated potential annual LFG production rate of more than 1-billion cubic feet.
- Maryland does not have a moratorium on the use of LNG.
- Baltimore Gas & Electric produces LNG at one of its Baltimore facilities. Other LNG producers are located in nearby Pennsylvania and Delaware.
- Maryland's natural gas pipeline network does not fully cover the state, leaving gaps in its CNG dispensing network, and limiting the ability of public sector fleets to meet federal and state AFV mandates/goals.
- Much of the state hosts centrally fueled fleets with predictable duty cycles that fit the parameters of ideal AFV fleets.
- The market for any liquid carbon dioxide that is produced as a byproduct of cleaned-up LFG may include Maryland's greenhouse industry.
- Some of Maryland's landfills are not adjacent to gas pipelines. Such sites (and possibly coal-bed methane sites in the north-west corner of the state) offer opportunities for demonstrating small scale liquefaction plants.

9.0 FINANCING PROGRAMS AND/OR TAX INCENTIVES

9.1 Federal Programs

Section 29 of the federal tax codes offered a pollution prevention tax credit for LFG-to-energy projects. Most existing gas recovery sites that had "binding contracts" for gas collection, prior to 1997, were eligible for those credits, but only through 2007. The program does not apply to sites not "grandfathered" by the 1997 deadline.

Although a number of proposals have been made to replace §29, no new federal program to encourage LFG reclamation is imminent.

Some existing §29-enhanced LFG recovery projects that produce electricity may discover that their electric sales contracts will expire prior to the 2007 tax credit expiration. It may be possible to convert those sites to LFG-to-CNG/LNG projects and maintain the tax benefits. On the other hand, given the capital cost of such a conversion and that only eight years of tax credits remain, the economics may not work.

9.2 New York State Programs

For public entities, New York State offers Environmental Bond Act funds to facilitate the purchase of AFV (such as mass transit buses) and the purchase of alternative fuel dispensing stations. However, those funds are competitive and are not available to the private sector.

For the private sector, New York State offers a tax credit toward the incremental extra cost of AFVs (with a maximum of \$10,000 per heavy-duty vehicle) and a tax credit of up to 50% of the cost of an alternative fuel dispensing station. Those credits can be quite valuable in the context of a comprehensive LFG-to-AFV program.

In urban contexts, such as on Long Island or in New York City, it may be possible to create a critical mass of AFVs, public and private, that share several fuel dispensers and rely on the same stream of LFG-to-CNG/LNG. The optimum volume of CNG/LNG needed to justify the clean-up and dispensing process may require a significant number of vehicles at the dispensing end of the chain. That model would include Bond Act funds for public vehicles and tax credits to private fleets. The remaining challenge is to price the fuel lower than the untaxed price of diesel for the public fleet and lower than the fully taxed price for the private fleet. One way to accomplish this is to eliminate all taxes on the LFG, including as it is dispensed as a vehicle fuel. Such a tax credit would help the private sector, which in turn would allow the public landfill sites the possibility of establishing a broad market for the cleaned gas.

To the best of our knowledge, no specific pollution prevention tax credit (for landfills or wastewater treatment plants) is now available in New York.

The New York State Department of Economic Development, through its Office of Recycling Market Development, offers matching grants of up to 50% of the capital cost (up to \$500,000) of the commercialization of a recycling system or process that has

direct benefits to the private sector. However the enabling legislation specifically excludes trash to energy projects.

In a 2/17/99 telephone conversation with Ms. Amy Schoch, Marketing Specialist, NYS Department of Economic Development, at telephone # 518-486-6291, we were informed that while LFG-to-energy projects are not eligible, the production of liquid carbon dioxide, as a byproduct could be funded by the state.

In a 2/17/99 telephone conversation with Mr. Jim Reese of NYSERDA, (at 518-862-1090, ext. 3251) we were informed that NYSERDA would entertain funding requests of up to \$250,000 for projects that linked landfills, wastewater digester gas, and AFVs, with carbon dioxide as a byproduct.

9.3 Maryland Programs

Maryland offers modest tax credits for the purchase of AFVs. After four years of the program we know of no applicants for the tax credit. The obvious reason for the lack of interest is that the tax credits are much too low to induce a private sector fleet operator to consider AFVs. Combined with the fuel-availability issues described above, Maryland fleet operators face a set of disincentives against AFVs rather than a comprehensive plan to encourage them.

10.0 CONCLUSIONS

The following conclusions arose from this study:

1. If LFG-to-CNG/LNG projects are to be economical, an emphasis must be placed on heavy-duty fleets in lieu of light-duty vehicles.
2. The technical issues associated with the gathering of LFG and its clean-up to pipeline quality has been solved for large landfills.
3. Only landfills that produce more than 1-billion cubic feet of LFG per year should be considered for LFG-CNG/LNG programs. Many landfills are smaller than that. However, New York's and Maryland's top half-dozen sites will fit within this screen.
4. The Fresh Kills landfill in Staten Island yields pipeline quality gas that is inserted into the local gas distribution network. However, no particular effort is being made to direct that gas to AFV fleets. The public policies that resulted in the Fresh Kills clean-up system need to be augmented to encourage the use of the cleaned gas as a vehicle fuel. If the economics of that model are not quite on target, NYS needs to examine the tax structure on the sale of cleaned LFG and on the sale of gas for AFVs. In-state produced gas used for AFVs, especially if its source is a landfill or a wastewater treatment plant, should be tax free for its entire lifecycle.
5. Because government agencies operate outside of the tax structure, municipal landfills and wastewater treatment plants should first be "linked" to municipal AFVs.
6. This study did not find a single existing landfill site that produces LNG and none that had a significant link to a large CNG dispensing network.
7. We did not find any wastewater treatment plants that produce pipeline quality gas. None of the existing LFG clean-up systems have been "scaled down" to the lower gas-flow rates of wastewater treatment plants.
8. There are no small-scale liquefaction plants on the market that have demonstrated their capacity to liquefy pipeline quality gas efficiently. Only the CryoFuel System claims to be targeting non-pipeline quality gas.
9. Existing, highly efficient and amortized LNG peak shaving plants should be relied on for the production of LNG, where cleaned landfill gas is "wheeled" to the plant to reduce the commodity and transportation cost of the basic gas. That model should also work in urban areas that rely on CNG and do not have nearby LNG sources. In some contexts new "let-down-cycle" LNG plant may be worth considering. In other contexts, the upgrading of existing gas processing plants, to also produce LNG, may be a viable concept.

10. In areas such as eastern-Maryland, that do not contain existing gas pipeline network, and where "wheeling" of cleaned landfill gas is not possible small scale liquefiers may be the only option for producing a product that can be moved off-site.
11. The lack of examples for linking LFG and wastewater digester gas reclamation to AFVs is not due to technical obstacles, but rather to the difficulty of establishing a comprehensive plan to link **LFG-to-clean-gas-to-CNG/LNG-dispensing**.
12. Given the "richness" of wastewater treatment digester gas, the long life of treatment plants, the steady and predictable flow rate and several other benefits, plants that produce only 500,000,000 cubic feet of digester gas may prove to be a productive long-term source of clean fuel. We suggest that any further analysis of the issues associated with wastewater digester gas be examined first in New York City.
13. The market for and the technology for producing liquid carbon dioxide needs to be tested.
14. If the federal §29 tax credit can't be replaced, statewide programs need to be examined. Natural gas and carbon dioxide produced from renewable sources and/or as a pollution prevention program, for in-state energy consumption, should be exempt from all state taxes, including fuel taxes if the gas is used in AFVs. In lieu of §29, all AFV fuel that is the direct result of pollution prevention at landfills and wastewater treatment plants should be exempt from the federal excise tax.
15. Not-for-profit public entities, such as the NY/NJ Port Authority, may be able to play a role in inducing "pollution prevention links" outlined above. They operate and manage facilities with concentrations of heavy-duty vehicle arrivals and departures, including airports with large "captive" fleets.
16. Long Island is ideal for demonstration of LFG-to-LNG/CNG. The Holtsville peak shaving plant can be a destination for "wheeled" gas, and a source for dispensed LNG, which could be shipped by truck to all parts of Long Island and to Westchester.
17. NY's existing LNG moratorium needs to lapse before any of the LNG-related suggestions discussed in this study can move forward. The LNG moratorium is the most significant impediment in New York State to a "vertically integrated" LFG-to-CNG/LNG network. With the moratorium in place, a "wheeling" model can only work within the context of existing CNG networks. The state's CNG dispensing infrastructure is limited and can only grow in contexts such as New York City where CNG's limitations on a vehicle's range is not an issue.
18. In Maryland, LNG (and LNG-to-CNG) could be the solution for establishing a statewide public sector AFV program, including for the eastern part of the state that is not near existing pipelines. However, Maryland needs a comprehensive plan for increasing the number of public sector AFVs and for inducing private sector AFVs.

11.0 SUGGESTED FOLLOW-UP WORK

The following five potential studies are listed in suggested priority order. Detailed work programs, budgets, funding sources and time lines would be developed after BNL selected its priorities from this list, or from a BNL generated variation.

11.1 Kryosol's Digester Gas Clean-up System

Our suggested "first priority" is to pursue the technical and economic issues associated with digester gas clean-up.

BNL, and possibly GRI, could fund a feasibility analysis and schematic design of Kryosol's methane cleaning and carbon dioxide production process applied to the three largest NYC wastewater treatment plants. The goal of this work would be to demonstrate (via site specific schematic designs and pro formas) that digester gas clean-up is economically feasible, even if the gas flow rate is less than that of most large landfill sites. The benefits of an urban context, with on-site electricity and on-site management staff can reduce the capital and operating costs of such a facility. The higher methane content and the steady/predictable flow rate of the gas can mitigate against the lower volume of gas.

A modular design would allow essentially the same hardware -- designed and manufactured in "bulk" -- to be placed at the three selected plants (and at other plants in other cities in the future), and allow for ease of maintenance and upgrading over the life of the wastewater treatment plant. The long-term result of this work may allow digester gas to become a permanent renewable resource that can be relied on by a localities as a low cost fuel for their AFV fleets. Indeed, the product flow rate (both as methane and carbon dioxide) may well exceed a locality's demand, thus allowing the extra methane to be delivered to private fleets.

In short, this "first priority" follow-up effort may well demonstrate that because of the long term (permanent) status of wastewater treatment plants, their proximity to urban AFV fleets, and the public ownership of both, the proposed linking of digester gas clean-up to AFV fueling can be economically viable.

11.2 Maryland

Our second priority would advance our work in Maryland, which has a centrally located highly efficient LNG production facility (BG&E's Baltimore "peak shaving plant"), and a natural gas pipeline network that runs near many of the state's landfill sites. However, the pipeline network does not cover the entire state. Thus, a number of state-operated fleets are unable to meet their AFV mandates because they are not near a CNG station or because they send their vehicles to areas of the state that are not served by CNG. The Maryland Energy Administration is seeking methods to bring CNG/LNG to such fleets.

Our work would examine the possibilities for "wheeling" pipeline-quality gas produced at landfill sites near existing natural gas pipelines for LNG dispensed from BG&E's peak shaving plant.

With BNL funding, and the cooperation of BG&E, the Maryland State Energy Administration, EPA's LMOP, and other interested parties, we would explore the feasibility of using cleaned landfill gas (starting with a single site near a pipeline, with an annual production rate of approximately 1,000 mmcf/yr), to be "wheeled" for LNG.

BG&E would dispense LNG to 5,000- or 10,000-gallon tankers. The utility now owns an LNG tanker, which it uses to deliver LNG to a nearby municipality. Thus, BG&E has the capacity to produce LNG and to ship it. The state has several landfills that may be suitable as a source of wheeled gas. The State Energy Administration is anxious to provide the infrastructure to Maryland's public vehicles so that they can comply with existing federal mandates. The possibilities for private sector participation are strong as well.

The Baltimore / Washington DC corridor is an excellent context to demonstrate a comprehensive LFG-to-LNG/CNG network.

11.3 Small Liquefiers at Landfills Not Adjacent to Pipelines

With the cooperation of the Maryland Energy Administration, identify one or two of the largest publicly owned off-pipeline landfill sites as candidates for demonstrating small scale liquefiers. Ideal sites would have existing gas collection systems. The ideal liquefier system would not require a separate LFG clean-up system. As of March, 1999, the best candidate seems to be the CryoFuel Systems. A demonstration at an actual landfill site would allow evaluation of CryoFuel's clean up technology as well as its ability to size the system to a particular LFG flow rate. The efficiency of the system -- its operating and maintenance costs -- could also be verified.

11.4 North-West New York State

The Niagara Recycling Facility in Niagara Falls (a publicly owned landfill site) is the largest in the state. EPA estimates that it has an annual landfill gas (LFG) generating potential of over 30-billion cubic feet per year. It has an on-site gas gathering system which feeds on-site electric generators. The local utilities include New York State Electric & Gas Corp. and Niagara Mohawk Power Corporation. As the state's largest "gas-to-wire" site the question, from this study's perspective, is how long will the economics of electric production continue to be favorable?

Our scope of work would be similar to that outlined above for Maryland. However, unless the existing NYS LNG moratorium is allowed to lapse, our efforts would be limited to evaluating the possibilities of "wheeling" for CNG.

11.5 Weehawken, NJ, Port Authority of NY/NJ Site

The Carlstadt NJ LNG plant may be a suitable "feeder" to a regional LNG/CNG dispensing network, especially if the dispensed product's cost is reduced by the "wheeling" model described above. The Port Authority of NY/NJ (PA) is seeking to expand its CNG dispensing network north from Jersey City to Weehawken, near the Lincoln Tunnel, and/or to Fort Lee, near the George Washington Bridge.

The PA has an existing investment in CNG vehicles. They seek to build on that investment. In a recent meeting with the PA's technical staff, they spoke of "maintenance issues" associated with heavy-duty CNG equipment and touted the benefits of bio-diesel as a "simple solution." The PA's negative experience with CNG may be turned around if their heavy-duty CNG vehicles switched to LNG or were fueled from an LNG/CNG dispenser, which could guarantee very pure methane.

Their interest in a Weehawken CNG (or LNG/CNG) dispenser stems not only from their own vehicles but also from the possibility of allowing NJ Transit to use the site as well as local municipal AFVs. The site would have a base load of public vehicles which can grow to include private fleets. For example, APA trucking, a regional carrier is located nearby as are numerous other private entities that move goods and people along the NJ side of the Hudson, as well as between NY and NJ via the Lincoln and Holland Tunnels and the George Washington Bridge.

CNG is now routinely moved through those Hudson River crossings. LNG is not. A growing ferry service industry is headquartered on the NJ side of the river. It too is a potential user of CNG/LNG.

The west side of the Hudson is experiencing enormous development pressure which in turn brings increased vehicular emissions. Given that a lot of the vehicles are concentrated in the Jersey City-to-Fort Lee corridor, the west side of the Hudson may have air quality problems that rival Manhattan's. In short, every parameter for AFV fleets and dispensing networks exists on the Jersey side of the Hudson.

The issue relative to this study is the following: can V+V, with BNL funding and PA technical support, create a comprehensive AFV framework that offers real economic advantages to public fleets and possibly to private fleets along the New Jersey side of the Hudson River?

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12.0 APPENDIX

- A.** NYSERDA Report in Brief: Report on Issues Regarding the Existing New York Liquefied Natural Gas Moratorium.
- B.** EBA/NY Inc. AFV Policy Statement

NYSERDA New York State Energy Research and Development Authority

William R. Howell, Chairman

F. William Valentino, President

Corporate Plaza West, 286 Washington Avenue Extension, Albany, NY 12203-6399

(518) 862-1090 • Fax: (518) 862-1091 • <http://www.nyserda.org/>

A New York State Energy Planning Board Report in Brief

Report: Report on Issues Regarding the Existing New York
Liquefied Natural Gas Moratorium

Project Manager: Charles B. Searle

Objectives: The New York Energy Planning Board has prepared this study to provide the Governor and the Legislature with information necessary to determine the need for further extension or modification of the existing State moratorium on the siting of new liquefied natural gas (LNG) facilities and intrastate transportation routes as required by Chapter 385 of the laws of 1997. The report examines existing laws and regulations that would affect new LNG facilities in New York and government initiatives in other states. It reviews existing use of LNG in New York, including safety issues and potential public concerns that may arise with lifting the moratorium. It also discusses the economic and environmental effects of increased LNG usage for New York State.

Discussion: The study concludes that LNG is as safe as other currently available fuels. LNG facilities have an excellent safety record that compares favorably with the records of facilities of competing fuels. The accident at the Staten Island Texas Eastern Transmission Company, which was a motivating factor in New York adopting the existing LNG moratorium, occurred after the tank was fully purged of LNG. A similar accident at a new LNG plant could not occur because the construction materials and tank design used at the Staten Island plant now are prohibited. There are economic and environmental advantages for allowing the construction of new LNG facilities as well as the intrastate transportation of LNG over new routes. Additionally, the study concludes that safety concerns associated with these facilities are adequately addressed by existing Federal, State and local statutes and regulations. For these reasons, the study recommends: that the Legislature discontinue the existing State moratorium by allowing the statute to lapse; and that Title 17, Article 23 of the Environmental Conservation Law, which imposes regulatory responsibilities on DEC, be repealed. In proposing these recommendations, the report recognizes the appropriate role of applicable local zoning and building permit laws and regulations to govern where such plants may be located in the same manner as local zoning and building codes currently apply to the siting of other fuel storage facilities, including petroleum products and propane.

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Environmental

Business Association

OF NEW YORK STATE, INC.

1223 PEOPLES AVENUE, TROY, NY 12180-3542

VOICE: 518-276-2164

FACSIMILE: 518-276-6380

EMAIL: info@eba-nys.org

ALTERNATIVE FUELED VEHICLE FLEETS:

POLICIES TO INDUCE ECONOMIC GROWTH, CLEAN AIR, LOWER TRANSPORTATION COSTS AND REDUCE DEPENDENCE ON IMPORTED FUEL

BACKGROUND:

The Alternative Fuel Vehicle Act of 1997 (AFVA-'97) offers tax credits to offset the incremental extra cost of AFVs and the cost of clean fuel dispensing stations. Its purpose is to induce private fleets to convert existing vehicles to AFVs or to replace diesel and gasoline powered vehicles with "original equipment manufacturer" (OEM) "clean fuel" products.

The tax credit for vehicles is based on a two tier approach, with the most inducements accruing to vehicles weighing over 14,000 lbs. This recognizes that NY's alternative fuel infrastructure is not yet extensive enough and that most AFV conversions or purchases will be by "centrally fueled" fleets with daily duty cycles that allow them to rely on their own fueling facility. As individual fleets build their own dispensing stations, a network of such facilities will allow other, smaller fleets, to rely on a more widely available fueling infrastructure.

AFVA-'97 is one of the most progressive alternative fuel legislative initiatives in the country. Still, it falls short of establishing sufficient economic incentives for most fleets and especially for fleets with medium - and heavy - duty trucks and buses.

- * The "after-tax-credit" extra cost of a 33,000 lb. AFV truck or school bus is \$8,000 to \$10,000;
- * the "after-tax-credit" cost of a small dispensing station is over \$125,000;
- * the fully taxed cost of on-site CNG (currently the only practical alternative fuel for NYS based medium -and heavy - duty fleets) is \$1.30 per "diesel equivalent gallon," in markets where fully taxed diesel can be dispensed at \$1.10 per gallon.

If NY's Alternative Fuel Vehicle Act of 1997 is to be successful, particularly with regard to medium and heavy duty urban fleets, the following additional **legislative** incentives and **administrative** policies need to be adopted.

NEW YORK STATE AFV TASK FORCE 1998-1999 AGENDA

I: Priority Legislative Items

1. Statewide legislation is needed to establish "Green Curbs" in urban areas: "Green Curbs" are specialized parking areas for AFVs that promote the sale and use of AFVs' and reduce urban air pollution. Green Curbs will be especially useful as an AFV delivery vehicle incentive by replacing high polluting vehicles in heavily populated areas. (Green Curbs are also listed as Priority Policy Item #1.)

2. Adopt a \$.50 "per equivalent gallon" tax credit for clean fuels purchased in NYS.

This incentive, which accumulates to the vehicle owner, promotes both AFVs and the economic development in NYS. This legislative incentive would be written with a sunset. The fiscal hit on revenues would be approximately \$1,500,000. This is based upon 1,000 privately owned AFVs driving 70 miles per day 240 days/year. This would replace 2,400,000 gallons of diesel fuel per year. The reduction in fuel use may be applied to SIP credit and nonattainment .

3. Rescind, reduce the 8.25% NYS/NYC sales tax on qualified alternate fuels dispensed in Heavy Duty Vehicles: Heavy Duty Vehicles (using EPA specifications) that use alternate fuels are 20-25% less fuel efficient . Removal of the sales tax would compensate for the increased fuel costs. Any sales tax revenue loss is compensated by a tax collection increase from the 25% extra fuel sold.

4. Eliminate or reduce NYS registration fees and provide special license plates for AFVs. Reduced fees would have a limited effect on Light Duty Vehicles (LDV) AFV sales. However, reduced registration fees for Heavy Duty Vehicles (HDV) can be a driving force for fleet implementation. The AFV license plates would make AFVs easy to identify for traffic enforcement at "Green Curbs" and provide market exposure to the general public. The fiscal impact of this incentive could be tracked by expanding the "fuel type" section on registrations.

6. Create a Governor's Task Force to report annual AFV progress: NYS DMV would report on the AFV license plates in service along with their characteristics. NYS Taxation and Finance could report on tax credits and rebate use. NYSERDA would report on the status of AFV programs, emissions reductions and economic development issues. The NYS Thruway and other toll collecting authorities would report on AFV usage patterns. State and local agencies with purchase mandates would report on their compliance. The PSC would report on alternate fuel pricing and availability. The data from these agencies will be presented by a lead agency to the Governor and legislature. Possible sources of funding include NYSERDA or DOE.

7. Implement an AFV marketing program: Provide information on AFV incentives, fueling stations and service centers. A comprehensive list of all the current incentives and services would greatly assist current owners and potential purchasers. Present marketing of AFVs is fragmented. A more cohesive approach is a critical step to induce AFV purchases. A clear reference guide would benefit state and local governments providing the best incentives. Presently DOE provides marketing support for the Clean Communities Program. This program could be leveraged with assistance from NYSERDA, EBA, AFV businesses and environmental groups. Field presentations would greatly assist in promoting AFV benefits and tax incentives. Both AFVs and the Clean Communities program could be promoted by using AFV delivery trucks for billboard advertising.

8. Support a "Clean Corridor" to Canada: Leverage NYS Clean Cities areas to establish Clean Corridors to Canada. Clean Corridors connected to Canada would promote AFV use, interstate commerce and provide NAFTA related economic development benefits. The Thruway Authority should continue their proactive role to facilitate the construction of fueling and charging infrastructure along these routes.