Biomethane in California Common Carrier Pipelines: Assessing Heating Value and Maximum Siloxane Specifications

An Independent Review of Scientific and Technical Information

SUMMARY REPORT

A Commissioned Report prepared by the
California Council on Science and Technology

CCST
CALIFORNIA COUNCIL ON SCIENCE & TECHNOLOGY

A nonpartisan, nonprofit organization established via the California State Legislature
— making California's policies stronger with science since 1988

Biomethane in California Common Carrier Pipelines: Assessing Heating Value and Maximum Siloxane Specifications

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Summary Report

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About CCST

The California Council on Science and Technology is a nonpartisan, nonprofit organization established via the California State Legislature in 1988. CCST responds to the Governor, the Legislature, and other State entities who request independent assessment of public policy issues affecting the State of California relating to science and technology. CCST engages leading experts in science and technology to advise state policymakers — ensuring that California policy is strengthened and informed by scientific knowledge, research, and innovation.

Note

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Acronyms and Abbreviations

AD	Anaerobic digestion
AGA	American Gas Association
ASTM	American Society for Testing and Materials
BTU	British thermal unit
C	Degrees Celsius
CARB	California Air Resources Board
CCST	California Council on Science and Technology
CO	Carbon monoxide
CO2	Carbon dioxide
CPUC	California Public Utilities Commission
CWC	Cellulosic waiver credits
F	Degrees Fahrenheit
FERC	Federal Energy Regulatory Commission
FID	Flame ionization detector
GHG	Greenhouse gas
GTI	Gas Technology Institute
HV	Heating value
LCFS	Low carbon fuel standard
LDCs	Local distribution companies
LNG	Liquified natural gas
m^3	cubic meter
mg	Milligram
MMBTU	Million British thermal units (also MBTU)
MSW	Municipal solid waste
NG	Fossil natural gas
NGC+	Natural Gas Council
O_2	Oxygen
OEHHA	California Office of Environmental Health Hazard Assessment
OH	hydroxyl
OPEX	annual operating costs
OSHA	Occupational Safety and Health Administration
PG&E	Pacific Gas and Electric
ppm_v	Parts per million by volume
ppb_v	Parts per billion by volume
PUC	Public Utility Commission (of any state)
RFS	Renewable fuel standard
RINs	Renewable identification numbers
RNG	Renewable natural gas
scf	Standard cubic feet
SG	Specific gravity
Si	Silicon

SMUD	Sacramento Municipal Utility District
SoCalGas	Southern California Gas
SDG&E	San Diego Gas and Electric
WN	Wobbe number
WWTP	Wastewater treatment plant

Executive Summary

In 2014, the California Public Utilities Commission (CPUC) adopted standards for pipeline injection of biomethane.[1] In order to reexamine two parts of the 2014 CPUC Decision, pursuant to California Senate Bill 840 (SB 840, 2016), the CPUC asked the California Council on Science and Technology (CCST) to produce an independent scientific assessment of the minimum heating value and the maximum siloxane specifications for biomethane transported in common-carrier pipelines. This report responds to that request.

Biomethane is biogas that has been processed to meet pipeline standards. Biomethane is a close substitute for natural gas (NG), but has a different origin. Like NG, biomethane composition can vary depending on the composition of its source material. NG and biomethane contain many of the same molecules, but in different quantities. The presence or absence of certain molecules in biomethane or NG can affect combustion, safety, and equipment durability. This report focuses on two variables of biomethane: the heating value (HV) and the siloxanes content.

The evidence suggests keeping the current minimum Wobbe Number (WN) and relaxing the HV specification to a level near 970 BTU/scf is unlikely to impact safety or equipment reliability. Relaxing HV specification to a level near 950 BTU/scf could affect safety.

Recommendation 1: Keep the Wobbe Number minimum requirements as they are now.

Recommendation 2: Reexamine regulations on heating value (HV) minimum levels. Initiate a regulatory proceeding to examine the option of allowing biomethane satisfying current WN limits and all other requirements, but with a HV as low as 970 BTU/scf.

The concentration of siloxanes is another issue of concern for biomethane injection into the common-carrier pipeline. During biomethane combustion, siloxanes are oxidized and form silica molecules, very similar to sand. Siloxanes are often found in wastewater and landfills and thus in biogas produced from wastewater treatment plants and landfills. Siloxanes are not expected to be present in dairy waste, agricultural waste, and forestry residues. While siloxanes can be removed from biogas at a relatively small cost, the biomethane may still not meet the current California standard of no more than 0.1 mg Si/m^3. At present, no standardized measurement protocol exists for dependable measurement of the 0.1 mg Si/m^3 specification.

1. Decision 14-01-034, Decision Regarding the Biomethane Implementation Tasks in Assembly Bill 1900 (AB 1900, 2012).

There is insufficient information available at this time to determine whether the current maximum limit of 0.1 mg Si/m^3 is too stringent, or not stringent enough, to meet safety requirements. Because some sources are very unlikely to have siloxanes — e.g. dairies, agricultural waste, or forestry residues — these sources could be held to a reduced and simplified verification regime. Additional testing and experimentation is required in order to more rationally set a siloxane standard in the future.

Recommendation 3: Support a comprehensive research program to understand the operational, health, and safety consequences of various concentrations of siloxanes.

Recommendation 4: At this time, there is not enough evidence to recommend any changes to the maximum allowable siloxanes concentration.

Recommendation 5: Consider the development of a reduced and simplified verification regime for sources that are very unlikely to have siloxanes, such as dairies or agricultural waste.

Recommendation 6: Monitor the American Society for Testing and Materials (ASTM) International process to adopt and test a standard test method for siloxanes.

Recommendation 7: Use the learnings from the siloxane research and the ASTM International process to revisit the siloxane maximum standards once more complete information becomes available.

Upgrading biogas to biomethane and injecting it into the common-carrier pipeline is not the only option. Minimally-processed biogas can also be used for on-site heat or electricity generation. But the current playing field is far from level. Current State and Federal regulations incentivize the use of biomethane for transportation and only for that purpose. Financial incentives through the California Low Carbon Fuel Standard (LCFS) and the Federal Renewable Fuel Standard (RFS) programs can be up to 18 times greater than the commodity value of the biomethane itself. The differential treatment under the RFS program, and the California Air Resources Board (CARB) regulations limiting electricity generation to only cap-and-trade credits rather than LCFS credits, creates a substantial market distortion away from electricity generation.

Recommendation 8: State and Federal agencies should examine whether the substantial differences in incentives for various uses of biogas/biomethane are consistent with the State and Federal policy intentions.

CCST is a nonpartisan, nonprofit organization established via the California State Legislature in 1988 to provide objective advice from California's best scientists and research institutions on policy issues involving science. CCST responds to the Governor, the Legislature, and other State entities who request independent assessment of public policy issues affecting the State of California related to science and technology. CCST produces rigorous, peer-reviewed reports following a process modeled after the National Academies.

Summary Report

Study Background

In 2014, the California Public Utilities Commission (CPUC) adopted standards for pipeline injection of biomethane.[2] In order to reexamine two parts of the 2014 CPUC Decision, the CPUC, pursuant to California Senate Bill 840 (SB 840, 2016), asked the California Council on Science and Technology (CCST) to produce an independent scientific assessment of the minimum heating value and the maximum siloxane specifications for biomethane transported in common-carrier pipelines. This report responds to that request. It provides an assessment of findings from a wide variety of sources, including peer-reviewed journal articles, industry funded work, trade publications, personal interviews, discussions with those involved with the various aspects of this industry, and independent modeling by the authors.

In order to answer questions posed by the CPUC, this study:

1. Presents an overview of biomethane.

2. Discusses minimum heating values for pipeline injection and maximum siloxane concentrations.

3. Summarizes options for blending biomethane to meet standards.

4. Suggests alternatives to common-carrier pipeline use.

5. Discusses the economics of alternatives to pipeline transportation of biomethane.

These issues are discussed more fully within this Summary Report and in the Full Report.

The science team studied each of the issues above. The science team and the Steering Committee collaborated through a deliberative, consensus-based process that was rigorously peer-reviewed to develop a series of findings, conclusions, and recommendations.[3]

The remainder of this Summary Report summarizes the background, data, and analysis underlying the recommendations stated above.

2. Decision 14-01-034, Decision Regarding the Biomethane Implementation Tasks in Assembly Bill 1900 (AB 1900, 2012).

3. We defined “findings, conclusions, and recommendations” as follows. Finding: Facts that can be documented or referenced and that have importance to the study. Conclusion: A deduction made based on findings. Recommendation: A statement that recommends what an entity should consider as a result of the findings, conclusions, and analysis.

Overview of Biomethane

Biomethane is a close substitute for natural gas.[4] Biomethane and natural gas share many characteristics but are not identical. Natural gas is composed primarily of methane, other higher molecular weight hydrocarbons (e.g., ethane, propane, butane), and inert gases, including carbon dioxide. Biomethane is also composed of methane and other inert gases, but typically does not include higher molecular weight hydrocarbons.

Biomethane and natural gas have very different origins. Natural gas is extracted from subsurface wells and processed to remove impurities and extract valuable hydrocarbons. Biomethane is upgraded biogas. Biogas is the result of anaerobic digestion by microbes and occurs naturally in waste products such as agricultural waste, wastewater organic matter, and digestible materials in landfills. Biogas can also be purposefully produced, such as in dairy waste digesters. The biogas is collected and upgraded to remove inert species and contaminants. Once biomethane is upgraded to be interchangeable with natural gas, it generally can be used for most applications.

Movement of natural gas from the point of extraction to the point of use is primarily by common-carrier pipeline. Transportation and distribution of biomethane can occur in dedicated biomethane pipelines. However, the more common option is to inject interchangeable biomethane into existing common-carrier pipelines, thus blending it with natural gas already being moved. An alternative use for biogas is combustion for heat or electricity generation either on-site or delivered off-site by dedicated pipelines. In some circumstances, using biogas in one of these ways may be the most economical option.

Combustion of biogas or biomethane releases carbon dioxide into the atmosphere, as does the combustion of natural gas. However, collection and purposeful use of biogas or biomethane avoids atmospheric release of methane (a very powerful greenhouse gas) or carbon dioxide (the most common greenhouse gas) that would have otherwise occurred.[5] Thus, using biogas or biomethane in place of natural gas leads to net reductions in greenhouse gas emissions if the biomethane avoids methane release or replaces natural gas (or other fossil fuels) that would have been used otherwise.[6] Those net reductions provide environmental benefits that motivate the State of California to encourage use of biogas or biomethane.

The bulk of this CCST report focuses on the option of upgrading biogas to biomethane and moving it through common-carrier pipelines. The costs of upgrading biogas to biomethane

4. Natural gas supplies roughly one third of California's energy and is used for generating electricity (32% of natural gas), in industry (37%), in homes (19%), in commercial buildings (11%) and for vehicles (1%).

5. Landfills generally capture and flare gases produced by underground anaerobic decomposition of organic material.

6. This assumes that the production and combustion of natural gas is reduced by the amount of natural gas replaced by biomethane.

(so it can be used interchangeably in the place of natural gas) is a significant factor in determining the economic viability of moving biomethane in common-carrier pipelines. This study focuses on interchangeability standards that allow biomethane to be introduced into common-carrier pipelines.

Although there are multiple options for using biogas, this report does not examine these alternatives fully. Instead, the report briefly highlights the Federal and State incentives for upgrading biogas to biomethane for injection into common-carrier pipelines, as well as using biomethane for transportation purposes.

In response to the CPUC request, the Science Team investigated the minimum heating value and maximum siloxane concentrations for safe and reliable interchangeability of biomethane and provided estimates of upgrading costs for alternative minimum heating values. Although there are additional important gas quality parameters that could be used to determine the suitability of any gas as interchangeable with natural gas, they are not within the scope of this work. A complete and thorough assessment of all gas quality parameters is necessary to evaluate a new gas source.

In the U.S., gas quality specifications are approved by regulatory bodies. For interstate pipelines, specifications are approved by the Federal Energy Regulatory Commission (FERC). Intrastate pipelines and local distribution companies typically have their specifications approved by a state-level, public utilities commission or public service commission. In California, that body is the CPUC.

Our discussion is based on the characteristics of gas that would allow it to be safe and reliable at the point-of-end use. However, most regulatory agencies apply gas quality regulations at the point at which the gas is injected into the system.[7] Such regulation (at the point of injection) ensures that gas quality will meet in-pipe and downstream standards regardless of changes in flow conditions. Although the Full Report discussion assumes that gas quality specifications will be applied to upstream injections, the Science Team considered whether there are ways of making the system more flexible by blending biomethane with natural gas upstream.

Heat Content for Common Carrier Pipelines

Heating value (HV) and Wobbe Number (WN) are commonly used measures of gas quality. HV, more precisely the higher heating value, is a measure of the heat available from combustion of the gas. WN (also called Wobbe Index or Wobbe) measures the rate of energy delivered through a fixed orifice at a constant pressure.[8] Both HV and WN are stated in terms of British Thermal Units (BTUs) per standard cubic foot (scf), or BTU/scf.

7. An American Gas Association 2009 survey showed that 54% of the tariffs were set at the point of receipt and 38% were set at the point of delivery. The rest were unknown.

8. WN is calculated by dividing HV by the square root of the specific gravity of the gas relative to air.

In determining ranges of acceptable gas compositions, HV and WN can be used together with other parameters. The WN significance was discussed in a white paper prepared by the NGC+ Interchangeability Work Group (a group of stakeholders, organized under the leadership of the Natural Gas Council). This document concluded: “The Wobbe Number provides the most efficient and robust single index and measure of gas interchangeability. There are limitations to the applicability of the Wobbe Number, and additional specifications are required to address combustion performance, emissions and non-combustion requirements.”

Natural gas HV can vary over a significant range, as can the HV of biomethane. Without upgrading, biogas has a much lower HV and WN than natural gas (often half). After upgrading biogas to biomethane, biomethane typically has a somewhat lower HV and WN than pipeline natural gas due to lack of higher-molecular-weight hydrocarbons. For that reason, this study examines minimum standards, and does not consider maximum standards.

In California and the U.S., regulations commonly set maximum and minimum HV specifications for injection into natural gas pipelines. Upper and lower bounds on the WN are less common. Distribution of a gas having a WN (or HV) that is too low can create health, reliability, and safety problems.

The CPUC established the current minimum HV and WN regulations in 2006 to accommodate anticipated imports of liquefied natural gas (LNG), which typically has a higher HV and WN than domestic gas supplies:

- “Rule 30” requires that any gas entering the pipeline system of Southern California Gas Company (SoCalGas) and San Diego Gas & Electric (SDG&E) must have a WN no less than 1279 BTU/scf and a HV of no less than 990 BTU/scf.[9]

- “Rule 21” requires that any gas entering the pipeline system of Pacific Gas & Electric (PG&E) must have a WN and higher HV consistent with the standards established by PG&E for each Receipt Point.

- Sacramento Municipal Utility District (SMUD) currently accepts only local biomethane via functionally-dedicated pipeline, but ensures the gas meets the Rule 21 specifications.

Regulations prior to 2006 allowed a lower HV of 970 BTU/scf. The CPUC re-considered and upheld the current rules in 2014. The CPUC cited lack of evidence that a less stringent HV specification would have a negligible effect on end-users.

9. Heating values in the regulations are technically the higher heating value.

Natural gas specifications encompass a maximum HV and a minimum HV for each natural gas source. Typical minimum HV requirements in the United States are within the range of 950 to 974 BTU/scf. However, it is unclear if gases close to these limits have routinely been delivered by these companies. A minimum HV specification does not guarantee that gas with this HV has actually been delivered to consumers.

Researchers for this CCST study searched published literature (both peer-reviewed and trade publications) and interviewed many in the industry. Several published works indicated negligible impacts of a lower HV to pipelines and end users.

A required WN for biomethane could be reached by controlling the inert gas concentrations (inerts) along with the HV. Relaxing the HV specification to a level near 970 BTU/scf should not affect safety if the Wobbe deviation from the adjustment gas and the maximum American Gas Association (AGA) lifting index are not exceeded. In Rule 30 regions, this would allow for a greater range of biomethane compositions, while minimum Wobbe and maximum inerts specifications will still ensure interchangeable operations. In Rule 21 regions, higher nitrogen blends with HV down to 970 BTU/scf should satisfy all other gas quality and interchangeability requirements. However, as Rule 21 regulates HV and interchangeability on a case-by-case basis, there may be regions where delivering gas with a HV near 970 BTU/scf may exceed the AGA lifting index limit.

In summary, scientific modeling and published literature provide evidence that reducing the California minimum HV specification to a level near 970 BTU/scf, while keeping the current gas interchangeability specifications, is unlikely to impact safety.

Existing evidence does not support further reduction of the minimum HV — say to 950 BTU/scf, the lowest current North American HV specification — without further research. There have been very few interchangeability studies at this low level for appliances tuned to historical gas supplies in California.

An important consideration is the cost of upgrading the biogas to biomethane, either to 990 BTU/scf or 970 BTU/scf. Allowing 970 BTU/scf for biomethane could substantially reduce the cost of producing biomethane. This cost reduction would be relevant even though there is substantial variability in upgrading cost across the different sources of biogas — landfill, waste water treatment plants, animal waste, or municipal solid waste (MSW) — and across various vendor estimates.

Based on data provided by biomethane equipment manufacturers, the report authors calculated mean upgrading cost and the range of cost estimates for the four different sources and have reported these costs in the Full Report. The mean estimates of additional cost of upgrading to 990 BTU/scf, rather than 970 BTU/scf, are between $1 and $5 per MMBTU. California Citygate prices of natural gas, for which the biomethane would substitute, are approximately $3 per MMBTU.

Findings, Conclusions, and Recommendations Related to Heating Values

Finding 1: California allowed a lower HV of 970 BTU/scf before 2006.

Finding 2: Other states have lower minimum HV, as low as 950 BTU/scf. The most common minimum HV requirement in the United States is approximately 970 BTU/scf.

Finding 3: The NGC+ Interchangeability Work Group determined the WN is the most efficient and robust single interchangeability index. Their interim guidelines specified a WN range of +/- 4% from the local historical average gas. These guidelines were implemented in Rule 30 and, along with the AGA lifting index, are sufficient to define the range of interchangeable biomethane supplies.

Finding 4: There is substantial variability in upgrading cost across varying sources of biogas and varying vendor-supplied estimates. Seven companies, out of 28 initially contacted, provided detailed cost estimates. Mean estimates of upgrading biogas to biomethane, at 970 BTU/scf, range from $5 to $18 per MMBTU. The mean estimates of the additional cost of upgrading to 990 BTU/scf rather than 970 BTU/scf are between $1 and $5 per MMBTU.

Conclusion 1: The scientific modeling by authors of this paper and in the literature provide evidence that keeping the current minimum WN and relaxing the HV specification to a level near 970 BTU/scf is unlikely to impact safety or equipment reliability.

Conclusion 2: The admittedly incomplete available evidence suggests that relaxing the HV specification to a level near 950 BTU/scf could affect safety.

Recommendation 1: Keep the WN minimum requirements as they are now.

Recommendation 2: Reexamine regulations on HV minimum levels. Initiate a regulatory proceeding to examine the option of allowing biomethane satisfying the current WN limits and all other requirements, but with a heating value as low as 970 BTU/scf.

Siloxane Concentrations for Common-Carrier Pipelines

Siloxanes are molecules with two or more silicon atoms attached to methyl radicals (CH_3) and joined by interspersed oxygen atoms. Siloxane compounds are used in industrial processes as anti-foaming agents and fire retardants. Siloxanes are also in many consumer products, such as personal care products and cosmetics. Thus, siloxanes are widely found in wastewater and household waste, as well as in raw biogas produced from wastewater treatment plants (WWTP) and landfills.

Siloxanes are very unlikely to be present in dairy waste, agriculture waste, and forestry residues because there is no known biological process that forms siloxanes.

During combustion, siloxanes are fully oxidized and form molecules of silica (SiO_2), the chief constituent of sand. Silica quickly condenses and is deposited as a glassy solid.

Deposition of silica can cause a wide variety of operational issues and hazards:

- Silica can build up on heat exchanger surfaces, can clog narrow passages, and can lead to abrasion of internal surfaces of turbines and engines.

- Silica particles can collect in oil of engines and require more frequent oil changes.

- As a thermal insulator and an electrical insulator, silica can lead to deactivation of sensors and to localized overheating.

- Silica particles can clog the catalytic fuel processing reactors and porous electrodes of fuel cell systems, leading to performance degradation.

- Post-combustion emissions control catalysts are highly susceptible to fouling by silica because particulates will clog pores of the catalyst bed and deactivate catalyst-active sites.

Possible direct health impacts are not well known and need more study:

- If released prior to combustion, siloxane compounds have overall very low environmental or health impact.

- Post-combustion, silica can form amorphous (not crystalline) silica nanoparticles which could potentially have detrimental health impacts. At levels expected in biomethane, the Occupational Safety and Health Administration (OSHA) limit for eight-hour amorphous silica inhalation will probably not be exceeded. However, this limit may not be relevant for silica in nano-particulate form,[10] which can be biologically active because of their large surface area to volume ratio. Therefore, the focus of any human health concern should be on the impact of silica nanoparticles and the potential toxicity associated with these particles.

- Other than the suggestive findings above, very little is known about the direct health impacts of silica nanoparticles.

10. In general, the size distribution of silica nanoparticles can range from 5 to 200 nm depending on how much agglomeration takes place before cooling.

In addition, there may be indirect health impacts:

- The mode of damage or failure is important to determining safety impacts of siloxanes. Some damage modes will result in immediate non-operation of the device due to fail-safe features installed on appliances. For example, the failure of a flame sensor due to silica deposition will shut off gas to the burner tip and prevent device operation. However, other damage modes could lead to important health impacts. Deposition that reduces combustion air flow and thus increases carbon monoxide(CO) emissions could go unnoticed. Flue gases discharged into occupied spaces could lead to possible health impacts, including death.

The maximum siloxane level in biomethane has been regulated by the State of California since 2014. California has set a "Lower Action Level" at 0.1 mg Si/m^3. The Lower Action Level is used to screen biomethane during the initial quality review and during periodic testing. When a biomethane producer is found non-compliant and shut-in, the gas would instead be flared or used in on-site combustion equipment.

Key to the appropriate standard are two issues: 1) the maximum siloxane concentration in biomethane that is both protective of human health and environment, as well as the safety and reliability of pipeline infrastructure and end use equipment; and 2) analytical procedures or methods which allow routine, accurate, and reliable measurement. If a minimum concentration of siloxane is established absent a reliable method for testing, monitoring will not be reliable.

Siloxane specifications vary between countries. Many do not have a numerical siloxane standard in place. Some ban pipeline injection of gas from landfills, wastewater sources, or both. Of countries with numerical siloxane standards, the Netherlands has a standard equal to 0.1 mg Si/m_3, while remaining countries have less stringent requirements (2–6 mg Si/m_3).

Determination of the standard should depend on information about concentrations at which problems occur. However, current California specifications are based on very limited data and involve significant extrapolation from that data. A small number of organizations have conducted controlled laboratory experiments on end-use equipment operated on natural gas with added siloxane. These tests were based on siloxane concentrations well above the current California standard, and linear extrapolations were used to derive the recommended limits.

There is some operational experience with siloxanes at biomethane projects across North America. Almost 50 operating projects inject biomethane into natural gas pipeline systems, but only one of these (Point Loma in San Diego) has been subject to a siloxane specification. Very little public data is available about concentrations of siloxanes present in the biomethane, providing little evidence for or against any particular numerical siloxane standard. It would be useful for SoCalGas to provide more clarity about how the Point Loma WWTP product gas was certified as in compliance with the siloxane standard. More clarity about the measurement technique, certifying laboratory, and expected detection limits would aid the development of additional projects seeking to demonstrate compliance.

Some manufacturers of natural gas-fueled equipment have instituted specifications for maximum allowable siloxane concentration to ensure proper operation. The current California standard of 0.1 mg Si/m^3 is lower than most, but not all, equipment specifications. The methods and data used to develop manufacturer standards are typically not available in the public domain. However, any setting of a siloxane standard should take account of manufacturer specifications, at the least to understand how many devices may be impacted at a certain siloxane limit. This does not imply that the siloxane specification need be lower than all manufacturer standards, as it may be more cost-effective to install supplemental scrubbing on particularly sensitive equipment.

Fortunately, siloxane can be significantly reduced (but not completely eliminated) from biomethane before it is injected into pipelines. The best available data on the concentrations of siloxanes at operational biomethane projects come from a Gas Technology Institute (GTI) investigation that examined post-treatment, upgraded biomethane from seven different landfill sites. Twenty-two of the 27 gas samples were below the reported detection limit (0.1 mg Si/m^3 for each compound), and the remaining five samples reported between 0.1 and 0.4 mg Si/m^3. Thus, these landfills were achieving results close to, but not verifiably in accordance with, the Rule 30 standard of 0.1 mg Si/m^3 for total siloxanes. According to the Coalition for Renewable Natural Gas, no manufacturer of siloxane removal equipment has thus far been willing to provide a performance guarantee for removal below 1 mg Si/m^3. The cost of siloxane removal appears to be somewhere above $1 per million BTU ($1/MMBTU) for most reasonable biogas flow rates.

In addition, it is possible for operators of costly equipment that is particularly sensitive to siloxane to remove the siloxane locally. Assuming that there is relatively little such equipment in California, this alternative could be more economical than enforcing a tighter standard for all biomethane pipeline injections.

The experience of current biomethane projects in other states shows that several currently active landfill projects are already able to remove siloxanes to below their reported detection limits. However, detection limits vary between methods and are generally not reported.

Concentrations at which laboratories can routinely and dependably measure siloxanes, as well as the definition of the phrase “no detect,” are very important considerations in setting standards. For a specification to be effective, labs must be able to test in a repeatable manner through a standardized, agreed-upon measurement protocol.

Many biomethane industry observers believe that the current siloxane standard is set below the detection limits of current technology. One view, consistent with that belief, is that no scientific consensus exists on a method for reliable measurement for the specification of 0.1 mg Si/m^3. On the other hand, California utilities maintain that the current siloxane standard is a detectable level. SoCalGas has reported working with (and verifying) an independent laboratory that specifies detection limits well below 0.1 mg Si/m^3. Several testing laboratories claim detection limits of 0.1 mg Si/m^3 or lower. However, the study team has not been able to test these claims independently.

A multi-year process to develop standard siloxane measurement methods is underway under the auspices of ASTM International. They are developing, vetting, and establishing a standard test method for siloxane measurement. This includes determining the gas-phase concentrations of volatile silicon compounds in the parts per billion by volume (ppb_v) to parts per million by volume (ppm_v) concentration range. At the conclusion of the ASTM International process, a standard method will be published, and the organization will have five years to complete the inter-laboratory study.

There are not enough data at this time to provide reliable guidance as to whether 0.1 mg Si/m^3 is too stringent or is not sufficiently stringent to meet safety and reliability requirements. The study team has not found convincing evidence for either relaxing or tightening the standard without significant further experimental work and data collection on real-world operations. The team believes that California should initiate a comprehensive research program to understand the operational, health, and safety consequences of various concentrations of siloxanes in biomethane. Furthermore, additional testing, analysis, and experimentation is needed to confirm that the current siloxane limit can be reliably measured using a standardized protocol (underway with ASTM International). Because a large number of landfill projects currently operate biogas collectors with cleanup equipment for biomethane production, systematic data collection on gas composition and any observed maintenance issues would advance our knowledge of real-world siloxane impacts significantly.

Some biomethane sources are not expected to contain siloxanes — for example, digesters processing dairy manure, source-segregated organic waste and yard waste, or agricultural waste. Biomethane from these sources is almost certain to meet the current California standard. Therefore, these sources should be held to a reduced and simplified verification regime to avoid unnecessarily encumbering the industry.

Findings, Conclusions and Recommendations Related to Siloxanes

Finding 5: Because of their broad use, siloxanes are often found in wastewater and landfills and therefore can be found in biomethane produced from wastewater treatment plants and landfills.

Finding 6: Siloxanes are not expected to be present in dairy waste, agriculture waste, or forestry residues.

Finding 7: During combustion, siloxanes are fully oxidized and form silica molecules. Deposition of silica can cause a wide variety of operational issues and hazards. Possible direct health impacts are not well known and need more study.

Conclusion 3: Current California siloxane specifications are based on very little data and involve broad extrapolation from that data.

Finding 8: Siloxanes can be removed at relatively small cost before injections into pipelines, but possibly not to the current California standards.

Finding 9: At present, no standardized measurement protocol exists for dependable measurement for the specification of 0.1 mg Si/m^3. Several testing laboratories claim detection limits of 0.1 mg Si/m^3 or lower. However, we have not been able to independently test these claims.

Finding 10: ASTM International is developing a standard test method for siloxane measurement and quantification in order to determine the gas-phase concentrations of volatile silicon compounds in the ppb_v to ppm_v concentration range. Once done, it will be tested by labs over a five-year period.

Conclusion 4: There is not enough information available now to determine whether 0.1 mg Si/m^3 is too stringent, or not stringent enough, to meet safety requirements.

Conclusion 5: Some sources are very unlikely to have siloxanes — e.g., dairies or agricultural waste. These sources could be held to a reduced and simplified verification regime to avoid unnecessarily encumbering sources that do not produce siloxanes.

Conclusion 6: Additional testing and experimentation are required in order to more rationally set a siloxane standard in the future.

Conclusion 7: There is not enough scientific evidence to support an increase or a decrease in maximum allowable concentrations.

Recommendation 3: Support a comprehensive research program to understand the operational, health, and safety consequences of various concentrations of siloxanes.

Recommendation 4: There is not enough evidence to recommend any changes to the maximum allowable siloxanes concentration at this time.

Recommendation 5: Consider the development of a reduced and simplified verification regime for sources that are very unlikely to have siloxanes, such as dairies or agricultural waste.

Recommendation 6: Monitor the ASTM International process to adopt and test a standard test method for siloxanes.

Recommendation 7: Use the learnings from the siloxane research and the ASTM International process to revisit the siloxane maximum standards once more complete information becomes available.

Options for Blending in Common-Carrier Pipelines

Blending of upgraded biogas with natural gas in or at the pipeline was discussed as an option for meeting requirements for delivered gas. The option is complicated and very specific to the situation at hand.

Typically, active blending could be accomplished by withdrawing a stream of natural gas from the pipeline, blending it with the upgraded biogas, and injecting the blended stream back into the pipeline. Reinjecting would allow the purchase price of natural gas to be recovered, along with the BTU value of the upgraded biogas. Another option would be for the pipeline operator to manage the mixing and reinjecting, presumably charging a fee for the service.

In some cases, it was proposed that upgraded biogas which does not meet the BTU specifications might be blended within the pipeline itself. This solution was discussed and is acceptable only if it could be assured that specifications would be met by the time the gas arrives at end-use equipment. Unfortunately, such in-pipeline dilution could be unreliable and lead to unpredictable changes in the quality of gas received by consumers, for two reasons. First, if the amount of upgraded biogas injected is large relative to local consumption, specifications may be violated even after dilution. Second, blending may not occur reliably in practice, due to transient or discontinuous injection, causing “slugs” of out-of-specification gas to arrive erratically at end-use consumers.

Current Environmental Protection Agency (EPA) rules economically preclude such blending: upgraded biogas not of pipeline quality at its pipeline injection point does not qualify for subsidies under the Federal Renewable Fuel Standard (RFS) program, subsidies that are far greater than the market value of the upgraded biogas. (See discussion below.) Whether an upgraded biogas producer would be allowed to blend the upgraded biogas would depend on local pipeline conditions as modeled by Local Distribution Companies (LDCs) and utilities.

Alternatives to Pipeline Transportation

Although this report has focused on regulations for upgrading biogas to biomethane and moving it on common-carrier pipelines, other uses of partially-upgraded biogas may be economically superior and environmentally at least as good. In many, if not most cases, upgraded biogas can be combusted for heat or electricity generation either on-site or delivered off-site by dedicated pipelines. These alternatives avoid some of the large upgrading costs. In such “medium BTU” projects, biogas would be consumed by an end-user on-site or after moving it a short distance by a direct private pipeline. Upgraded biogas or biomethane on-site can provide heating for buildings and agricultural processes. Gas turbines, reciprocating engines, or fuel cells can generate electricity. Although there is typically a limit to on-site needs, electricity can be sold through the electric grid in large quantities once the appropriate grid connection is established.

Moving interchangeable biomethane on common carrier pipelines co-mingles it with natural gas. The resulting product would be the same to the end-user as it would have been without the biomethane. In that way, biomethane on common carrier pipelines substitutes on a one-for-one basis with natural gas.[11]

In the same way, upgraded biogas combusted for heat or electricity generation (on-site or delivered off-site by dedicated pipelines) substitutes on a near one-for-one basis with natural gas or with the fuel that would otherwise have been used for those purposes. For electricity generation in California, the fuel would normally be natural gas and thus upgraded biogas would substitute on a nearly[12] one-for-one basis with natural gas. For electricity generated in other states, the fuel could be coal and thus the greenhouse gas-reduction benefits would be larger than with substitution for natural gas.

The State may want to create a more level playing field so these options could be compared on their merits.

Findings and Conclusions Related to Alternatives to Pipeline Transportation

Finding 11: Blending of upgraded biogas with natural gas in or at the pipeline might allow safe pipeline movement of upgraded biogas that does not meet all specifications, but only under very specific conditions, typically dictated by the pipeline company.

Conclusion 8: An important question for the State of California is under what conditions biogas should be upgraded to biomethane and the biomethane transported on common-carrier pipelines. An alternative is to use upgraded biogas (not meeting all pipeline standards) or biomethane on-site, typically for generating electricity.

Market Distortions Stemming from Existing California and Federal Regulations

As referenced in earlier sections of this study, there exist a variety of Federal, State, and Local regulations that provide incentives for renewable fuels in the energy mix. Energy policies are crafted by different regulatory bodies with differing visions and strategies for energy use. Given a lack of formal policy coordination with a consistently applied strategy, over time these policies and regulations may create unintended market distortions by giving some combination of energy sources and energy uses preferential advantages over other combinations. Such market distortions, which are perhaps unintended by policy makers, are an important consideration for biomethane.

11. Even if that co-mingled gas is used for transportation, say as compressed natural gas for trucks, the biomethane is substituting for natural gas, not substituting for diesel fuel. This pathway does not result directly in the development of compressed natural gas (CNG) vehicles.

12. The substitution may not be exactly one-for-one because the electricity generator efficiency may be higher or lower than the unit that would otherwise be used to generate electricity.

For example, in some circumstances using the upgraded biogas on-site or transporting "medium BTU" biogas short distances by private pipeline would be economically more attractive than upgrading to biomethane and blending in existing common-carrier pipelines, if these options were on a level playing field. However, the playing field is far from level. Under current regulatory rules, "medium BTU" upgraded biogas does not qualify for incentives under the Federal RFS program or the state LCFS program. These Federal and State incentives are generally many times greater than the market value of the biomethane; thus, the regulations sharply distort the choice toward upgrading and transporting on common-carrier pipelines. This is but one of the ways in which current large State and Federal energy subsidies provide strong market distortions toward upgrading biogas to biomethane and blending in common-carrier pipelines for transportation use, even if on-site upgraded biogas use and/or electricity generation is an economically and possibly environmentally more attractive option.

This section outlines the set of energy regulations and policies that create this consequence and outlines several example use cases. A comparison of three example use cases illustrates these market distortions for biogas.

<u>Biogas upgraded to biomethane, and transported in pipelines, notionally for transportation use:</u>

In addition to its sales value, a biomethane supply can receive a credit through the Low Carbon Fuel Standard (LCFS) if it can be certified that the biomethane is used notionally[13] or actually for transportation in California. The credit varies with the certified pathway: biogas recovered from a landfill may have an LCFS carbon intensity (CI) of 47 gCO_{2e}/MJ (.051 tonnes/MMBTU). On the other end of the scale, two animal waste biogas digesters[14] were certified by California with an average CI of negative 264 gCO_{2e}/MJ. The large negative CI is based on a credit for avoiding methane releases. For a recent LCFS price of $126 per tonne of CO_2, biomethane produced from landfill gas receives a LCFS credit of $6/MMBTU; that produced by the animal waste digesters receive a LCFS credit of $48/MMBTU.

In addition, the biomethane can receive a credit through the Federal Renewable Fuel Standard (RFS) program from selling Renewable Identification Numbers (RINs), once the EPA certifies the pathway and the EPA compliance conditions are met.[15] Each million BTU of

13. The actual molecules may not be used, but there could be a contractual agreement to inject the biomethane into the pipeline and for the user to withdraw the co-mingled biomethane and natural gas from the pipeline. The vast majority of these projects are for biogas produced or captured outside of the State of California.

14. Only animal waste digesters have been certified for such a low CI and only two have been certified to date, both from outside of California.

15. The ease of pathway certification depends on management of the EPA. The current EPA administration has been very restrictive in granting new pathway applications.

biomethane earns about 11.7 D3 RINs.[16] Currently the D3 RIN price is $2.45 per RIN. At this price, the credits are worth about $29/MMBTU and do not depend on whether they avoid methane releases.

The value of natural gas at common-carrier pipeline intake, which determines the commodity value of biomethane, net of the pipeline tariff for transporting the gas, is currently less than $3/MMBTU.

The producer of biomethane is able to receive the financial benefits of both the LCFS and the RIN credits if the biomethane meets all of the California and Federal requirements.

Costs of certifying that the project meets all of the State and Federal requirements reduce the value of these incentives to the producer. Revenues may also be reduced because the notional or actual user of the biomethane may also require part of the regulatory incentives as compensation, leaving less for the biomethane project operator.

Biogas upgraded to biomethane, and transported in pipelines for residential, commercial, industrial, or electricity generation:

Biogas or biomethane can be used to generate electricity using a gas turbine, reciprocating engine, or fuel cell. It could be used for heating or other purposes in the residential, commercial, or industrial sectors. Each of these uses substitutes for other fuels, often natural gas.

In addition to the commodity value, the biomethane would receive cap-and-trade credits valued at less than $1/MMBTU. This would be the entire regulatory incentive.

Biogas or biomethane used to generate electricity if electricity is used for transportation:

If it can be established that the electricity is used for transportation, say for electric vehicles, then in addition to the electricity value, renewable electricity in principle could receive LCFS credits in place of cap-and-trade credits. The LCFS credit may be roughly the range cited above: between $6 and $48 per MMBTU. In addition, biomethane for electricity could receive a credit through the Federal RFS from selling RINs.[17] Under EPA rules, one RIN is available for each 0.022 MWhr of renewable electricity. So, one MMBTU of biomethane

16. D3 is the RIN for cellulosic biofuels. Prior to July 2014, biogas projects qualified as Advanced Biofuel. In 2014, the EPA took final action to qualify "compressed natural gas," "liquefied natural gas," and electricity produced from biogas from "landfills, municipal wastewater treatment facility digesters, agricultural digesters, and separated MSW digesters" as cellulosic and advanced fuels under the Federal RFS program. This rulemaking allowed these pathways to qualify for D3 (cellulosic biofuel) RINs, rather than just the D5 (advanced biofuels) RINs. Thus many biogas projects can receive the D3 RIN price. Currently D3 RINs have a market price of $2.45 while D5 RINs have a market value of $0.76, less than one-third as much.

17. https://www.epa.gov/renewable-fuel-standard-program/approved-pathways-renewable-fuel.

might provide 5.7 RINs — about half as many as earned for biomethane used directly in transportation — for electricity generation with a 50% efficiency factor. These RINs would provide about $15 of revenue, only about half as much as if the biomethane were used directly in transportation.

Comparison of the regulatory incentives.

The differential regulatory incentives per MMBTU of biogas or biomethane are summarized in the following table:

Biogas or Biomethane Use	**Incentive per MMBTU of biogas or biomethane**
Biogas upgraded to biomethane and transported in pipelines, used for transportation	$35 – $77
Biogas or biomethane used for residential, commercial, industrial, or electricity generation	$1
Biomethane used to generate electricity used for transportation, if the pathway has been certified	$21 – $63

As a caveat, these comparisons have not yet considered cost of producing raw biogas, natural gas pipeline extension costs, biomethane quality measurement equipment, off-gas treatment equipment, transformers, switchgear, buildings, interconnecting piping and electrical, civil work, mechanical engineering, permitting, land costs, legal costs, license costs, project management, commissioning services, spares, certification costs, or taxes. Which option would be best under a level playing field would depend upon a variety of costs (including biogas upgrading), and on the alternative revenue streams — the price at which biomethane can be sold from pipelines and the price at which the electricity can be sold. These comparisons simply illustrate the consequences of the existing regulatory incentives extended by the State of California and the Federal government, rules that have changed substantially over time.[18]

It should be noted that greenhouse gas-impacts of biomethane injected into a pipeline and used for transportation are the same as the greenhouse gas impacts of biogas used to generate electricity, so differential impacts on emissions cannot be the justification for these differences in financial incentives.

18. As noted in footnote 16, for example, in 2014, the EPA took final action to qualify "compressed natural gas," "liquefied natural gas," and electricity produced from biogas from "landfills, municipal wastewater treatment facility digesters, agricultural digesters, and separated MSW digesters" as cellulosic and advanced fuels under the Federal RFS program, thus greatly changing the value of the RINs.

In each case, using one MMBTU of biomethane offsets one MMBTU of natural gas[19] that would otherwise be used. The biomethane is co-mingled with natural gas in the pipeline and is not distinguishable from the natural gas. If there is a small percentage of biomethane in the pipeline, only a small percentage of the transportation fuel[20] will be biomethane, even if the user has a contract to purchase the biomethane and have it injected into the pipeline. Similarly, one MMBTU of biomethane used to generate electricity also results in one MMBTU less of natural gas used for electricity generation. For projects that avoid methane release, such as dairy waste digesters, the greenhouse gas impacts of the avoided methane release likewise do not depend on whether the biomethane is used for transportation or for electricity generation.

These examples illustrate the role of "stacking" regulatory incentives, where the regulatory incentives of the LCFS can be combined with the regulatory incentives of the RFS. As noted above, the producer of biomethane is able to receive financial benefits of both the LCFS credits and the RIN credits if the biomethane is used directly or indirectly for transportation. For such projects, the stacking may result in total magnitude of regulatory incentives greater than that initially intended by either the State of California or the U.S. government because each designed its own program independently of the other program (even though the greenhouse gas impacts of biomethane injected into a pipeline and used for transportation are identical to the greenhouse gas impacts of biogas used to generate electricity). [21]

These examples also show the financial incentives through the LCFS and the RFS programs can be a factor of 10 to 20 greater than the market value of the biogas or the biomethane itself. Under current regulations, the profitability of biogas and the relative profitability of different uses of that biogas depend fundamentally on how California and EPA interpret their rules. Regulatory rules are dominant in shaping the economic choices facing the biogas or biomethane producer.

Very little biomethane is being used in California currently, and so the incentives to date apply only to a small amount of biogas upgraded to biomethane. The total cost is therefore relatively small. However, State regulatory bodies can be expected to look years into the

19. One MMBTU of natural gas, if combusted, would emit 0.057 tonnes of carbon dioxide into the atmosphere. Therefore, one MMBTU of biomethane avoids the release of 0.057 tonnes of carbon dioxide into the atmosphere, for generation of electricity or for use in transportation in California.

20. Use of the co-mingled natural gas and biomethane rather than natural gas alone does not convert trucks to compressed natural gas and thus the substitution is not biomethane replacing diesel fuel.

21. The LCFS was created after the RFS was in place, but at that time RIN prices were so small – between $0.05 and $0.10 per RIN – that LCFS developers could have ignored the RIN value. In addition, not until 2014 did EPA create the rule that classified most biogas projects as cellulosic. The EPA rule was applied nationwide; it was not specific to California and thus the California LCFS would not have been fundamental to the EPA decision.

future and estimate what could happen. If the biomethane industry grows substantially in California and throughout the United States, and if these regulatory incentives remain at their current levels, the total costs could become substantial in future years.

Regulatory agencies, including Federal and State agencies, could establish regulations to provide equivalent incentives for all environmentally-attractive use of biogas or biomethane, thus putting all socially beneficial options on a more level playing field. Updated regulations could be expected to take into account local environmental impacts of the various options. However, regulatory rules which put each environmentally-equivalent use of biogas or biomethane on a more level playing field would provide incentives for developers to select the most economically and socially attractive options.

Findings, Conclusions, and Recommendations Related to Market Distortions Stemming from Existing California and Federal Regulations

Finding 12: Financial incentives through the California Low Carbon Fuel Standard (LCFS) and the Federal Renewable Fuel Standard (RFS) programs can be a factor of up to 18 times greater than the commodity value of the biomethane itself. Both the LCFS and RFS programs have volatile prices; thus investments are subject to substantial regulatory risk.

Finding 13: Biomethane producers can stack financial incentives; they can receive both the financial incentives of the LCFS and those of the RFS if it can be demonstrated that the biomethane is used for transportation. If it is used for purposes other than transportation, neither incentive is available. Stacking may result in total magnitude of regulatory incentives greater than initially intended by either the State of California or the United States government.

Conclusion 9: The differential treatment under the Federal Renewable Fuel Standard program creates a substantial market distortion away from electricity generation and toward direct use of biomethane. In addition, if CARB regulations allow electricity to obtain only cap-and-trade credits rather than LCFS credits, that regulatory difference adds an additional substantial financial market distortion away from electricity generation.

Recommendation 8: State and Federal agencies should examine whether the substantial differences in incentives for various uses of biogas and biomethane are consistent with the State and Federal policy intentions.

About CCST

CCST is a nonpartisan, nonprofit organization established via the California State Legislature in 1988 to provide objective advice from California's best scientists and research institutions on policy issues involving science. CCST responds to the Governor, the Legislature, and other State entities who request independent assessment of public policy issues affecting the State of California related to science and technology.

Study Process

CCST organized and led the study reported on here. Members of the CCST Steering Committee were appointed based on technical expertise and a balance of technical viewpoints. Appendix I in the Full Report provides information about CCST's Steering Committee membership. All experts who contribute to the study were evaluated for potential conflicts of interest. Under the guidance of the Steering Committee, a team of experts (science team) assembled by CCST developed the findings based on original technical data analyses and a review of the relevant literature. Appendix J in the Full Report provides information about the science team. The lead author was also an *ex officio* Steering Committee member. In order for the Steering Committee to oversee the work of the science team, it was important for the Steering Committee to interact regularly with the lead science team members.

The science team studied each of the issues identified in the scope of work, and the science team and the Steering Committee collaborated to develop a series of findings, conclusions, and recommendations.

The committee process ensured that conclusions were based on findings, and recommendations were based on findings and conclusions, as well as on the underlying data and analysis. Both the science team and the Steering Committee members proposed draft conclusions and recommendations. These were modified based on peer review and discussion within the Steering Committee, along with continued consultation with the science team. Final responsibility for the findings, conclusions, and recommendations in this Summary Report lies with the Steering Committee. All Steering Committee members have agreed with these findings, conclusions and recommendations, as well as with the underlying analysis and discussion. However, because this is a consensus document, individual Steering Committee members undoubtedly would have phrased the ideas differently or might have changed the emphasis had they been writing this document alone. Any Steering Committee member had the option of writing a dissenting opinion, but no one requested to do so. The findings, conclusions, and recommendations expressed in this publication are those of the Steering Committee, and do not necessarily reflect the views of the organizations or agencies that provided support for this project.

This report has undergone extensive peer review; peer reviewers are listed in Appendix N in the Full Report, "Expert Oversight and Review." Nine reviewers were chosen for their relevant technical expertise. More than 300 anonymous review comments were provided to the science team and Steering Committee (study team). The study team revised the report in response to peer review comments. In cases where authors disagreed with the reviewer, the response to review included their reasons for disagreement. A report monitor, appointed by CCST, reviewed the responses to comments to ensure an adequate response and when satisfied, approved the report.

Data and Literature Used in the Report

The science team reviewed and analyzed existing data from both voluntary and mandatory reporting sources relevant to biomethane injection; peer-reviewed scientific literature; and non-peer reviewed reports and documents if they were topically relevant and determined to be scientifically credible by the authors and reviewers of this volume. The science team did not collect any new data solely for this report but did do original analysis of available data from a variety of sources. Significant gaps and inconsistencies exist in available voluntary and mandatory data sources both in terms of duration and completeness of reporting. Gaps and data quality issues in the reporting limited this analysis and may warrant adoption of additional quality assurance, reporting, and data handing requirements. When appropriate, proprietary data were requested by CCST from the CPUC and from utilities. The utilities provided some, but not all of the requested data. Similarly, CCST requested additional data from peer reviewers regarding siloxanes analysis and laboratory techniques. However, in most cases, the reviewers were unable to provide any additional data beyond anecdotes.

Despite the data limitations, information gathered from multiple independent sources gives largely consistent results, and the authors believe these report findings are generally accurate and representative of biomethane injection in California. Additional data in the future might change some of the quantitative findings, but, absent some major external influence, it is unlikely these will fundamentally alter the report findings.

CCST is a nonpartisan, nonprofit organization established via the California State Legislature — making California's policies stronger with science since 1988. We engage leading experts in science and technology to advise State policymakers — ensuring that California policy is strengthened and informed by scientific knowledge, research, and innovation.

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SPECIFICATIONS — AN INDEPENDENT REVIEW OF
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