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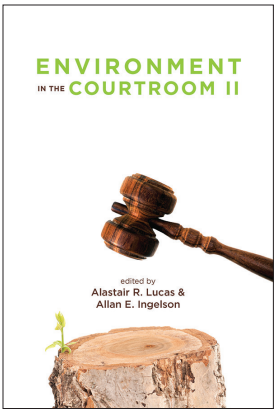

ENVIRONMENT IN THE COURTROOM II

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25

Enforcing Canada's Federal Methane Regulations for the Upstream Oil and Gas Industry

Allan Ingelson[1]

Introduction

Methane (CH_4), a potent greenhouse gas (GHG), has a global warming potential of more than seventy times that of carbon dioxide (CO_2) over a twenty-year period.[2] Methane is a significant component of natural gas.[3] Environment and Climate Change Canada (ECCC) monitors national GHG emissions and has reported that the Canadian oil and gas sector was responsible for releasing 25 percent of the nation's GHG emissions during the period 1990 to 2012, with trends indicating a continuous increase in the volume of methane emissions. In 2017, ECCC reported that 44 percent of Canada's methane emissions were from the same industry.[4]

In light of Canada's commitments under the *Paris Agreement*,[5] on June 29, 2016, Prime Minister Justin Trudeau announced that by 2025 the federal government would reduce national methane emissions from the oil and gas industry to 40–45 percent below the 2012 levels.[6] The federal government has promoted the *Pan-Canadian Framework on Clean Growth and Climate Change*, which is a national plan directed toward reducing the effects of climate change, under which more stringent methane emission standards have been recommended.[7] In April 2018, pursuant to section 332(1) of the *Canadian Environmental Protection Act*,[8] ECCC published "Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)," in Part II of the *Canada Gazette*.[9] These regulations apply to methane emissions from a

variety of upstream facilities, such as gathering and transmission pipelines; natural gas gathering, boosting, and transmission compression stations; and natural gas processing plants. The regulations largely focus on the extraction, primary processing, transportation, and storage of hydrocarbons.[10] The 2018 federal methane regulations that are currently being phased in are designed to establish uniform national requirements to further significantly reduce methane emissions from upstream offshore and onshore operations.

The Federal Methane Regulations

The federal methane regulations are designed to reduce the immediate or long-term harmful effects of methane emissions and the associated volatile organic compounds (VOCs).[11] Some of the negative health effects of methane emissions are cardiovascular and respiratory morbidity, heart and asthma attacks, and premature adult mortality.[12] In 2020, it was reported that the upstream oil and gas industry emitted 34 percent of the nation's VOCs.[13] The regulations focus on reducing methane emissions from the largest and emerging sources in Canada's upstream oil and gas industry: equipment leaks, venting, and new oil and gas wells.[14] ECCC estimates that the regulatory requirements to further reduce the volume of emissions by prompting the installation of new equipment should, by 2025, result in an emissions reduction equivalent to 232 million tonnes of CO_2 by 2035.[15]

EQUIPMENT LEAKS

According to ECCC, oil and gas facility equipment leaks account for 34 percent of the industry's emissions.[16] In section 2 of the regulations, the term "fugitive emissions" refers to natural gas leaks from equipment defined as "the emission of hydrocarbon gas from an upstream oil and gas facility in an unintentional manner."[17] The regulations focus on reducing these emissions from larger facilities—those that receive more than 60,000 standard m^3 of hydrocarbon gas during a 12-month period.[18] These larger facilities are responsible for approximately 75 percent of Canada's vented emissions.[19] Addressing a smaller number of larger sources of emissions (facilities) reflects a high leverage approach. To reduce emissions, section 29 of the regulations require operators to carry out leak detection and repair programs as follows:

> Operators of a facility must . . . establish and carry out at the facility a) a regulatory leak detection and repair program [LDAR] that

> satisfies sections 30–33; or b) an alternative leak detection and repair program referred to in subsection 35(1) that results in at most the same quantity of those fugitive emissions as would result from a regulatory program referred to in paragraph a).[20]

As far as the types of LDAR options that are available to facility operators, subsection 35(1) of the regulations provide flexibility in regard to the types of leak repair programs employed on the condition that the repair provides the same required reduction in emissions.

Section 32 of the regulations provides that, in most cases, a leak must be repaired within thirty days of it being detected:

> A leak from an equipment component that is detected, whether as a result of an inspection or otherwise, must be repaired a) if the repair can be carried out while the equipment component is operating, within 30 days after the day on which it was detected; and b) in any other case, the equipment component must be repaired within the period before the end of the next planned shutdown unless that period is extended under Section 33.[21]

In regard to facility inspections, the regulations provide that:

> An equipment component at an upstream oil and gas facility must be inspected . . . on or before the later of May 1, 2020, and the day that occurs 60 days after the day on which production at the facility first began; and . . . at least 3 times/year and at least 60 days after a previous inspection.[22]

The regulations mandate three annual inspections.[23] The types of technologies that will be used during inspections, such as infrared cameras, sniffers, drones, and satellite systems, are specified in the regulations to avoid arguments and disputes that could arise regarding whether there have been emissions that exceed the level permitted under the regulations.

The federal requirements convey the increased emphasis that ECCC is placing on operators to take action to prevent, detect, and repair equipment methane leaks in a timely manner to further significantly reduce the volume of emissions from larger oil and gas facilities. The fact that time periods are

specified in the regulations by which operators must complete equipment repairs should prompt facility operators to pay closer attention to the current volume of emissions from equipment leaks. In addition to the general provisions in the regulations that govern equipment leaks, there are specific provisions that apply to different types of equipment.

It is estimated that 20 percent of methane emissions from the Canadian oil and gas industry are from pneumatic device leaks.[24] A variety of automated instruments called pneumatic devices are employed throughout the industry that utilize natural gas to pump liquids and for other purposes. Some of these devices release methane into the atmosphere. As with other types of oil industry equipment, the regulations prescribe operating efficiency standards for pneumatic controllers and pumps.[25] The methane regulations require operators to replace certain types of high-bleed pneumatic controllers that produce a larger volume of emissions with low bleed or no-bleed controllers that will release a smaller volume of emissions than in the past. As with the other types of equipment, the repairs and/or equipment replacements must be completed within the time period specified in the regulations. As with other types of equipment, to provide facility operators with reasonable notice to budget for equipment upgrades or purchase new equipment to replace existing equipment, the provisions that apply to pneumatic devices are scheduled to come into force in 2023.[26]

VENTING

Venting is a common industry practice that releases methane directly into the atmosphere, which accounts for 23 percent of oil and gas industry methane emissions.[27] As natural gas is used to control pressurized equipment, including pumps in multiple industry operations, methane is intentionally released from equipment in processing facilities through vents. The regulations are designed to reduce by 95 percent the volume of methane that is intentionally vented from larger oil and gas facilities. To achieve this objective, section 26 of the regulations creates an annual venting limit for an upstream oil and gas facility to no more than 15,000 m^3 of hydrocarbon gas during a year. One exception to the maximum emissions limit in the regulations provides flexibility to facility operators and allows them to apply for approval to vent methane for safety reasons in exceptional cases, such as to avoid an explosion, an emergency depressurization, or a plant maintenance upset at a larger gas processing facility.[28]

In non-emergency situations, as an alternative to venting gas, the regulations require operators to capture and use at least 95 percent of the methane in facilities for a beneficial purpose rather than releasing and wasting the gas. The regulations stipulate that, at a minimum, 95 percent of the gas must be captured and used for one of three beneficial purposes stipulated in the regulations. Section 5 of the regulations require a minimum equipment operating efficiency as follows: "[h]ydrocarbon gas conservation equipment that is used at an upstream oil and gas facility must be operated in such a manner that at least 95% of the hydrocarbon gas is captured and conserved."[29] Section 7 of the regulations stipulates that gas must be captured and conserved in one of the three following methods:

> (a) used at the facility as fuel in combustion device that releases at most 5 percent of the combusted hydrocarbon gas to the atmosphere as hydrocarbon gas;
> (b) delivered; or
> (c) injected into an underground geological deposit for a purpose other than to dispose of the gas as waste.[30]

In regard to the first option, the regulations specify that no more than 5 percent of the gas can be released. The second option, "delivered," refers to piping the gas to be sold and used. The third option, subsurface injection (also referred to as enhanced recovery), requires natural gas to be reinjected into an oil and gas reservoir to avoid the release of methane into the atmosphere.

Another type of equipment is compressors, which account for approximately 9 percent of Canada's methane emissions. These are mechanical devices used to increase the pressure in pipelines to move natural gas from production sites to consumers.[31] Different types of compressors emit different levels of methane, and the regulations contain special provisions that limit the volume of emissions that can be vented from different types of compressors.[32] To reduce the volume of emissions from each type of compressor, there is a federal requirement that industry operators complete annual measurements to ensure that the emission limits stipulated in the regulations are satisfied. Section 14(a) requires measurement of gas flow volumes as the first step toward further reducing the volume of methane emissions. Section 16(3) requires operators to take initial and subsequent gas flow measurements during specific time periods, as follows:

> The flow rate must be initially measured on January 1, 2021, if the compressor is installed at the facility before January 1, 2020, and the 365th day after the day on which the compressor was installed at the facility in any other case; and subsequently, the period that ends on the 365th day after the day on which a previous measurement was taken.

Section 14 provides for optimal equipment performance that takes into account the different types of compressors used at different sites, and the regulations focus on regular equipment maintenance and efficiency to minimize the level of emissions.[33] As with other types of equipment, compressor operators are required to conserve or destroy methane to reduce the volume of methane in the atmosphere and meet the relevant gas release limits tailored to the type of compressor. Corrective action is required if emissions exceed the limit applicable to the compressor, which depends on the installation date, the type of compressor, and its rated brake power.[34] Timelines of thirty days and ninety days are specified in the regulations to complete the required work on compressors to reduce methane emissions.[35]

Another potential source of methane emissions addressed in the regulations is hydraulic fracturing (HF) operations and well completions at newly drilled oil and gas wells.

HYDRAULIC FRACTURING AND COMPLETION OF OIL AND GAS WELLS

HF refers to the process used to create cracks or fractures in a rock that allows oil and gas to move more freely to the well surface. It is an essential process at most shale oil and gas wells today in order for there to be economic hydrocarbon production.[36] However, fluids that contain methane in solution flow back to the wellsite surface and can release the gas into the atmosphere if not properly managed. Recently, technology has been refined to detect and monitor methane releases from oil and gas wells. Employing satellite data, atmospheric methane emission trends in North America have been analyzed and compared before and after unconventional shale gas development. It has been reported that the concentration of fugitive emissions has increased in areas with shale oil and gas development.[37] Compared to conventional wells, it is estimated that in some areas HF of shale oil and gas wells can release 40

to 60 percent more methane into the atmosphere, where more than 8 to 12 percent of the methane escapes through equipment leaks and venting.[38]

To prevent methane emissions from new oil and gas wells drilled throughout Canada, section 11(2) of the regulations entitled "No Venting," prohibits venting at new well sites and requires combustion/destruction of the gas or the capture and use of natural gas for a beneficial purpose. The section provides that "hydrocarbon gas associated with flowback at a well . . . must not be vented during flowback but must instead be captured and routed to hydrocarbon gas conservation equipment or hydrocarbon gas destruction equipment." The prohibition on venting gas at new oil and gas wells will prevent an increase in methane emissions from these wells.

In light of pre-existing provincial standards at the time the federal regulations were adopted in 2018 in British Columbia and Alberta that limit emissions from HF of oil and gas wells, section 13 of the federal regulations entitled "Non-application—British Columbia and Alberta" provides:

> Sections 11 and 12 do not apply in respect of an upstream oil and gas facility that is located in
> **(a)** British Columbia, if the facility is subject to the requirements with respect to well completion involving hydraulic fracturing that are set out in the guideline entitled *Flaring and Venting Reduction Guideline*, published by the Oil and Gas Commission of British Columbia in June 2016; and
> **(b)** Alberta, if the facility is subject to the requirements with respect to well completion involving hydraulic fracturing that are set out in the directive entitled *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting*, published by the Alberta Energy Regulator on March 22, 2016.[39]

Section 13 of the regulations provides that operators which satisfy the existing provincial requirements in British Columbia[40] and Alberta,[41] do not have to comply with the new federal standards in the regulations as well, as the federal government concluded that the 2016 provincial requirements that apply to emissions from HF and completion of new wells were adequate.[42]

In 2018 and 2019, the Alberta Energy Regulator revised *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting*[43] and created *Directives 084*[44] and *017*,[45] which further contribute to the province's ongoing

efforts to create provincial emissions reduction requirements that better align with the 2018 federal regulations.

Since then, the federal government has provided broader equivalency agreements for the regulations in Alberta, British Columbia, and Saskatchewan.[46]

Enforcement

There is no reported decision on a completed enforcement action under the federal regulations adopted in 2018.[47] In the United States, in 2012, the first emissions reduction rules were released and then in 2016, "Oil and Natural Gas Sector—New Source Performance Standards" were developed by the US Environmental Protection Agency (EPA) and adopted to reduce oil and gas industry emissions further.[48] However, in responding to the former President Donald Trump's goals to reduce the number of federal regulations and regulatory actions that may burden domestic energy production and development, in 2017 the US Bureau of Land Management rescinded its rule "Oil and Gas: Hydraulic Fracturing on Federal and Indian Lands,"[49] and in 2018 the EPA changed its emissions reduction requirements.[50]

The first enforcement action initiated during the Obama administration was taken against a natural gas gathering, transportation, and processing company for venting excess emissions. The action was settled in April 2018.[51] Pursuant to section 113(b) of the *Clean Air Act* (*CAA*)[52] and *Pennsylvania Air Pollution Control Act*,[53] the US Department of Justice, EPA, and the Pennsylvania Department of Environmental Protection filed a complaint against MarkWest Liberty Midstream & Resources, LLC, and Ohio Gathering Company, LLC (collectively MarkWest), for contravening the "Prevention of Significant Deterioration" provisions,[54] and the "Non-Attainment New Source Review" provisions,[55] due to venting excess emissions in Pennsylvania and Ohio.[56] In addition to being charged for releasing excess emissions from its facilities, the MarkWest was charged for failing to secure the required permits and the failure to maintain records for its stand-alone facilities and compressor stations. The defendant expressly denied any liability for contravening the emissions limits.[57] Federal and state regulators sought injunctive relief and civil penalties.[58]

According to Christopher Rimkus, managing counsel for MarkWest, workers had arrived at a site to carry out routine pipeline maintenance.[59] The maintenance activities were performed daily, weekly, or monthly to avoid the

buildup of condensate in gas gathering and transmission pipelines. The operations required venting gas to reduce any pressure in the pipeline before site maintenance activities could proceed. The federal government agents arrived at the site for inspection at approximately 8 a.m.; they halted routine maintenance activities, began questioning the workers, and collected samples. The agents finished the site inspection and made requests for production of documents. However, no additional action was taken by the federal agents at that time.[60] The managing counsel noted that after the execution of the federal search warrant, it became clear to him that "the search warrant was based in large part on a number of misconceptions." Specifically, the operations "were not occurring in secret" as they "were routinely scheduled," and the activities in question "did not vent the larger volume of the entire pipeline segment to the atmosphere—but a much smaller amount when inserting or retrieving a tool."[61] The managing counsel also noted that:

> Employees capture any natural gas liquids (NGLs) or other liquids that may be in the barrel in a storage vessel and do not release them to the ground. The public was categorically not at risk from the operations and no evidence has ever been presented to substantiate any claim to the contrary. Worker safety is protected during the operations as the studies conducted pre-search warrant attest to.[62]

The action taken by the federal and state regulators was framed as an "Air Pollution Emergency Claim" pursuant to section 303 of the *CAA*. Counsel for the defendant reported that the basis for the search warrant and preliminary discussions with both the Department of Justice and the EPA focused on protecting industry workers and public health. He notes that "previous and subsequent scientific studies demonstrate there was no imminent and substantial danger to workers or public,"[63] and that the "EPA, state regulators and industry have traditionally been under the impression that emissions from the operations in question were de minimis."[64]

After the site inspection and the review of its operations, the corporate defendant "identified a small subset of its sites (less than 10%) where emissions might have been above Pennsylvania state de minimis permitting thresholds."[65] The managing counsel also noted that there was no motivation or benefit for the company not to acquire the relevant permits, as they were easily obtainable either for minor sources of emissions or under other criteria.

Furthermore, operational design changes are easy and inexpensive to make so that the emissions fall below "de minimis" levels.[66] In addition, the defendant operator had previously investigated and evaluated new technologies for sampling and estimating the level of VOCs in emissions from its operations and had previously undertaken design enhancements that substantially reduced methane, VOCs, and methane emissions from its compressor stations and stand-alone facilities in Pennsylvania and Ohio.[67]

Notwithstanding the above practices and a denial of liability, the company settled the enforcement action before trial.[68] In the US Consent Decree, both the defendant operator and governments acknowledged that "the settlement agreement was negotiated in good faith to avoid further litigation and that it is fair, reasonable, and in the public interest."[69] The settlement provides for payment of a US $610,000 civil penalty and completion of three supplemental community environmental improvement projects costing the operator a minimum of US$2 million, designed to reduce emissions from oil and gas facilities.[70]

As part of what we refer to as a creative sentence in Canada, the 2018 settlement agreement required the operator to install air pollution control equipment at more than three hundred facilities to reduce emissions further and improve air quality in Pennsylvania and Ohio.[71] The EPA estimates that the new emissions controls will result in a reduction of 706 tons per year of VOCs and decrease annual emissions by 91.5 percent from the company's natural gas gathering system.[72] Under the settlement agreement, the operator must also install and operate ambient air monitoring stations near two compressor stations. The information collected from the monitoring stations about the nature and volume of emissions from the company's operations must be shared with the general public. Furthermore, the operator must make available and share with other industry operators its innovative technologies developed to reduce emissions and allow other operators to use through licences on a royalty-free basis, these technologies to further reduce emissions.[73]

In light of the federal methane reduction regulations, could an enforcement action that poses similar issues arise in Canada? I submit yes, as section 1 of the Canadian regulations indicate that, as in the United States, they are designed to prevent environmental deterioration from methane emissions and the associated VOCs and to protect the health and safety of Canadians. The Consent Decree/settlement agreement in the MarkWest enforcement action

is 104 pages long.[74] Canadian counsel may find it is useful to consider the issues that arose in the US enforcement action and how they were resolved. The following fourteen actions provide some examples of those that the US corporate defendant agreed to take to reduce the possibility that it and other industry operators would contravene the US methane emissions regulations:

1. To ensure the defendant's managers, employees, and contractors are aware of the enforcement action to reduce the potential for releasing excess emissions in the future, the defendant must provide a copy of the settlement agreement to all of its officers and managers to ensure that employees and contractors whose responsibilities may include compliance with the agreement are made aware of the terms of the agreement and the defendant company must place an electronic version of the agreement in a section of its internal website related to environmental matters. The company is clearly responsible for ensuring that all employees and contractors that perform any future work carry out that work in compliance with the terms of the agreement;[75]

2. The agreement specifies the type of emissions reduction technology that must be used at compressor stations and the minimum efficiency (98 percent) that must be achieved to destroy and reduce emissions;[76]

3. A date is specified in the settlement agreement by which the defendant operator must implement the specified emissions reduction program;[77]

4. For the purpose of complying with the agreement, the defendant company is obligated to calculate the mass of the VOC emissions;[78]

5. In regard to improving the containment of liquids at compressor stations and facilities to prevent emissions, new facilities that are built must incorporate liquid containers with grounded steel receptacles that are covered at all times when not in use;[79]

6. The financial penalty is shared between the federal and state governments with 80 percent to the federal government and 20 percent to the state government, with interest payable on any amount that is past due at a rate specified in the agreement;[80]

7. The financial penalty is not tax-deductible;[81]

8. The settlement agreement prohibits the defendant from using the reduced emissions from projects completed under the creative sentence, for clean development emissions reductions that include emissions offsets and obtaining, trading, or selling any emission reduction credits;[82]

9. In regard to the sale or transfer of its facilities, the agreement provides that the obligations are binding on the successors or assignees of the

company,[83] and that the company must provide written notification to a successor or assignee and the government(s) of the existence of the agreement before the closing of the sale or transfer;[84]

10. The defendant must condition any sale or transfer of ownership or operation "of any Covered Facilities upon the execution by the Third Party of a modification" to the agreement "to make the terms and conditions of [the agreement] related to the ownership or operation of the transferred Covered Facilities applicable to the Third Party";[85]

11. The defendant must spend a minimum of US$2 million to implement the projects to reduce emissions under the creative sentence,[86] and the projects must not be the ones that the defendant was planning or intending to build, carry out, or implement other than for the purpose of settling the enforcement action;[87]

12. The company must share with other industry operators the lessons learned from the enforcement action by posting information on its website and offering educational presentations that include hosting four demonstration or training sessions per year during a three-year period;

13. In regard to transferring the proven innovative emissions control technology that the defendant developed, it must provide, on a royalty-free basis, licences to other operators to use its proprietary design proven to decrease liquid accumulation and emissions. To promote rapid adoption and use of the innovative technology by other operators, the defendant must make available on a website that is publicly accessible no later than six months after the effective date of the agreement, a royalty-free licence and information on the design of the technology. The defendant must make its technical staff available in person at every educational session to demonstrate the installation and adoption of the VOC emissions reduction technology. The defendant must create comprehensive educational materials on the installation and maintenance of the technology to reduce emissions;[88]

14. Regarding ambient air quality monitoring of emissions from compressors, the defendant must install and operate, for a minimum of 720 days, one meteorological station and two air sampling stations to sample and analyze the level of total VOCs and reduced sulphur compounds. The defendant must submit, by 120 days from the effective date of the agreement, an ambient air monitoring plan to the EPA for approval. The defendant must follow the approved monitoring plan and submit quarterly information reports and annual reports to the EPA.[89]

In addition to the actions required under the settlement agreement, three specific practices that could be taken to protect workers from emissions include:

1. Incorporating standard operating procedures into training materials that include protocols for response to alarms;
2. Laminated job safety checklists for each site; and
3. Respiratory protection for changing filters at compressor stations.[90]

Conclusion

The Canadian federal methane regulations should further reduce the volume of methane that is released from equipment leaks and venting at facilities and new oil and gas wells. Starting on January 1, 2020, facility operators have implemented LDAR programs. The regulations require the implementation of LDAR programs within a specified time period at facilities along with three annual equipment inspections. Some provisions in the regulations were to be phased in during the five years following the regulations coming into effect in order to allow facility operators to budget for equipment upgrades and replacement. The regulations create a cap on the volume of emissions that can be vented from facilities. There is a maximum venting limit from larger oil and gas facilities of 250 m^3 of methane per month or a cumulative annual total of 3,000 m^3. ECCC now has the technical capability to detect and measure the volume of emissions from facilities to enforce new venting limits. To comply with the venting limits, operators have two basic options. The preferred option is to capture and use otherwise wasted methane for beneficial purposes, such as facility heating or generating electricity. A second, less desirable option, is a more efficient combustion (flaring) of natural gas, which results in a smaller volume of emissions than venting. The regulations prohibit venting at new oil and gas wells and require gas capture.[91] The regulations indicate that the current Alberta, British Columbia, and Saskatchewan provincial requirements are equivalent. Therefore, operators that satisfy the provincial standards in those provinces do not have to satisfy the federal emissions reduction standards as well. However, in other provinces such as Manitoba, where new oil and gas wells are being drilled and hydraulically fractured, operators must satisfy the federal requirements. As there are no reported Canadian prosecutions to date under the federal methane regulations that have gone to

trial and been settled, the MarkWest enforcement action provides examples of the types of issues that arose in an earlier methane emissions enforcement action and the significant financial consequences for the US pipeline operator that failed to comply with similar US federal regulations. Should a similar enforcement action be taken in Canada in the future, the US MarkWest case provides examples of the conditions agreed to by the corporate defendant and prosecutors in the United States that could also arise in Canada.

NOTES

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17 *Supra* note 9.

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21 *Ibid* at s 32.

22 *Ibid* at ss 30(1)–(3).

23 *Ibid*.

24 *Supra* note 15.

25 *Ibid* at ss 37(1), 37(2), 39(1).

26 *Ibid*.

27 *Supra* note 15.

28 *Ibid*.

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31 *Supra* note 2.

32 *Supra* note 9, ss 14(b), 16(3).

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53 PL 2119, No. 787, 1959, as amended.

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55 42 USC §§ 7501-7515.

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57 *Ibid*.

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60 *Ibid*.

61 *Ibid*.

62 *Ibid*.

63 *Ibid*.

64 *Ibid*.

65 *Ibid*.

66 *Ibid*.
67 *Ibid*.
68 *Supra* note 51.
69 *Supra* note 56.
70 *Ibid*.
71 *Ibid*.
72 *Ibid*.
73 *Ibid*.
74 *Ibid*.
75 *Ibid* at para 8.
76 *Ibid* at para 13.
77 *Ibid* at para 14.
78 *Ibid* at para 11.
79 *Ibid* at para 23.
80 *Ibid* at para 24.
81 *Ibid* at para 27.
82 *Ibid* at para 47.
83 *Ibid* at para 3.
84 *Ibid* at para 4.
85 *Ibid* at para 5.
86 *Ibid* at para 28.
87 *Ibid* at para 29.
88 *Ibid* at para 28.
89 *Ibid* at para 28.
90 *Supra* note 9.
91 *Ibid* at s 11(2).