Natural Gas Supply Association

February 10, 2014

Ms. Melissa Jurgens, Secretary
Commodity Futures Trading Commission
Three Lafayette Centre
1155 21st Street, NW
Washington, DC 20581

RE: RIN Nos. 3038-AD99 and 3038-AD82—Comments on Proposed Rulemakings Regarding (1) Position Limits for Derivatives, 78 Fed. Reg. 75,680 (Dec. 12, 2013) and (2) Aggregation of Positions, 78 Fed. Reg. 68,946 (Nov. 15, 2013)

The Natural Gas Supply Association ("NGSA") appreciates the opportunity to submit comments in response to the Notice of Proposed Rulemaking, Position Limits for Derivatives, 78 Fed. Reg. 75,680 (Dec. 12, 2013) (the "2013 NOPR") recently issued by the U.S. Commodity Futures Trading Commission (the "Commission" or the "CFTC"). References made herein to the Commodity Exchange Act (the "CEA" or the "Act") refer to that statute as amended by the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010 (the "Dodd-Frank Act").

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Established in 1965, NGSA represents integrated and independent companies that produce and market approximately 40 percent of the natural gas consumed in the United States. NGSA encourages the use of natural gas within a balanced national energy policy and promotes the benefits of competitive markets to ensure reliable and efficient transportation and delivery of natural gas and to increase the supply of natural gas to U.S. customers.

NGSA submits these comments to help the Commission to achieve the goals Congress set when authorizing it to impose speculative position limits. NGSA members stand to incur substantial compliance costs if the 2013 NOPR is finalized as proposed. In some circumstances, NGSA members would have to reduce the scope of their risk management programs in order to comply with the rules, thus increasing the price risk they bear and the costs borne by the ultimate end-users of the natural gas NGSA produce: the American consumer.

We do not believe it was the intention of the Commission and certainly not of Congress that commercial end-users, such as NGSA members, whose primary purpose in trading commodity derivatives is to manage physical commodity-related price risk, should bear the brunt of the burden associated with speculative position limits. We believe the intention behind speculative position limits is to curb *excessive speculation*, not to foreclose or discourage legitimate risk management activities used by commercial market participants. Unfortunately, numerous portions of the proposed rules and Commission's preamble guidance go beyond the statutory directives and goals, and, rather than place limits "as appropriate" and as "necessary" to curb excessive speculation, instead prescribe and limit the types of risk reducing activities our members and others in the energy commodity business engage in. We hope that our comments to the 2013 NOPR will help the Commission refocus its speculative position limits policy to more carefully target "excessive speculation." Our comments in support of these views are presented below.

I. Overview of Necessary Changes to the Proposed Rule

As discussed in further detail below, NGSA recommends most importantly that the Commission:

1) Preserve the bona fide hedging exemption for positions that qualify under CEA section 4a(c)(2) definition of a "bona fide hedging transaction or position" but that are not specifically enumerated by the Commission, i.e., "non-enumerated" bona fide hedge positions such as those described under current 17 CFR 1.3(z)(3), and provide for a clear, time-limited, and transparent process for Commission approval of a "non-enumerated" hedge that both (i) satisfies the statutory mandate to exempt bona fide hedges from position limits and (ii) complies with the statutory definition of the term "bona fide hedge." See section III.A.
2) Clarify the interpretation of the "economically appropriate" criterion for the bona fide hedging position definition to accommodate a wide array of prudent commercial risk management practices. See section III.B.
3) Reconsider, strike, or, at a minimum, revise certain incorrect Commission conclusions that certain risk reducing hedging activities used by natural gas commercial participants, particularly anticipated hedging activities, are not bona fide hedges. See section III.C.
4) Clarify and correct Commission analyses of bona fide hedges used in the natural gas and related industries, including that (i) using natural gas derivatives to hedge LNG exposure is not a cross-commodity hedge and (ii) when the price to be charged for a physical commodity (for example, electricity) is based on a natural gas price, using natural gas derivatives to hedge that exposure qualifies as a "same commodity" hedge, because the derivatives reference the commodity that is referenced in pricing the cash market transaction, rather than a cross commodity hedge. See section III.D.
5) Determine that Trade Options and other physical energy commodity options should not be subject to speculative position limits, or, at a minimum either exempt them from position limits or withdraw such proposal in its entirety until and unless the Commission justifies such proposal. See section IV.

6) Increase the spot-month position limit levels for Henry Hub Natural Gas referenced contracts to be consistent with CME Group's or ICE's estimates of deliverable supply and more generally the significant new sources of natural gas. See section V.A.
7) Permit substantially higher limits for cash-settled contracts and remove the prohibition on the trader carrying a position in the physical delivery contract. See section V.B.
8) Avoid an aggregation standard that requires aggregation based on ownership of an entity alone. See section V.C.

II. Legislative and Statutory Background

A. Recent impetus for speculative position limits

We welcome the fact the 2013 NOPR has used historic examples of "excessive speculation" to "inform" the Commission's proposal: (1) the speculative trading of the Hunt Brothers in the silver markets from 1979-1980 and (2) the speculative trading of Amaranth in the natural gas markets in 2006.[1] Amaranth and the Hunt Brothers shared one important feature in common: both were "pure speculator[s]"[2] that did not have financial or physical exposures that offset the risk exposures created by their extremely large natural gas or silver derivatives portfolios (respectively). The lessons provided by these two historical cases are valuable to consider as they illustrate the specific type of harm speculative position limits can and should surgically target.

The case of Amaranth is particularly instructive because it led Congress to identify certain regulatory gaps that gave rise to recent legislative actions, including the Dodd-Frank Act, that provide the Commission the authority it is claiming in issuing the 2013 NOPR. The Amaranth Report recommended therefore, most pertinently, that:

1) Congress should give the Commission authority to regulate electronic OTC markets (e.g., ICE at the time);[3] and
2) The Commission "should monitor aggregate positions on NYMEX and ICE… for all of the months in which contracts are traded, not just for contracts near expiration." [4]

The Investigations Sub-Committee's recommendations in the 2007 Amaranth Report were similar to findings made in 2006 by the Investigations Sub-Committee's 2006 report on

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[1] 78 Fed. Reg. 75,680, 75,685 (Dec. 12, 2013) ("2013 NOPR").

[2] Id. at 75,692 at note 103 ("Amaranth was a pure speculator that, for example, could neither make nor take delivery of physical natural gas.").

[3] Excessive Speculation in the Natural Gas Market, Staff Report with Additional Minority Staff Views, Permanent Subcommittee on Investigations, United States Senate, Released in Conjunction with the Permanent Subcommittee on Investigations, June 25 & July 9, 2007 Hearings ("Amaranth Report"), at 8.

[4] Id.

"The Role of Market Speculation in Rising Oil and Gas Prices."[5] The regulatory gap that these reports identified related to oversight – the need to "monitor aggregate positions" in electronic over-the-counter ("OTC") markets. Congress gave the Commission the authority to fill this regulatory gap in 2008.[6]

B. The Commission's expanded authority and expanded responsibilities under the Dodd-Frank Act

The amendments introduced by the Dodd-Frank Act in 2010 granted the Commission additional authority to prevent "excessive speculation."[7] Specifically, new CEA section 4a(a)(2) authorizes the Commission to impose speculative position limits for all contract months, not just the spot month. When the Commission exercises this CEA section 4a(a)(2) authority, CEA sections 4a(a)(5) requires that the Commission concurrently establish speculative position limits for swaps that are economically equivalent to futures contracts subject to CEA section 4a(a)(2) position limits. Similarly, CEA section 4a(a)(6) requires such limits to apply position limits on an aggregate basis to contracts based on the same underlying commodity across certain enumerated venues.[8] In short, the Commission has all of the regulatory authority it needs to prevent another "excessive speculator."[9]

The Dodd-Frank Act also bounded this authority in three important ways. First, the position limits regime that the Commission imposes must be promulgated by addressing the "goals" of CEA sections 4a(a)(2)(C)[10] and 4a(a)(3)(B). CEA section 4a(a)(3)(B) directs the Commission to balance the following four factors when exercising its CEA section 4a(a)(2) authority:

(i) to diminish, eliminate, or prevent excessive speculation as described under this section;
(ii) to deter and prevent market manipulation, squeezes, and corners;
(iii) to ensure sufficient market liquidity for bona fide hedgers; and

[5] ''The Role of Market Speculation in Rising Oil and Gas Prices: A Need to Put the Cop Back on the Beat,'' Staff Report, Permanent Subcommittee on Investigations of the Senate Committee on Homeland Security and Governmental Affairs, U.S. Senate, S. Rpt. No. 109–65 (June 27, 2006), at 7.

[6] See, e.g., Subtitle B-Significant Price Discovery Contracts on Exempt Commercial Markets, Title XIII, The Food, Conservation, and Energy Act of 2008, Pub. L. 110-246 (2008), available at http://www.gpo.gov/fdsys/pkg/PLAW-110publ246/pdf/PLAW-110publ246.pdf/.

[7] "The current regulatory system was unable to prevent Amaranth's excessive speculation in the 2006 natural gas market." Amaranth Report at 3.

[8] These enumerated venues are (1) contracts listed by DCMs; (2) with respect to FBOTs, contracts that are price-linked to a contract listed for trading on a registered entity and made available from within the United States via direct access; and (3) SPDF Swaps.

[9] 2013 NOPR at 75,692 at note 103.

[10] "In establishing the limits required under subparagraph (A), the Commission shall strive to ensure that trading on foreign boards of trade in the same commodity will be subject to comparable limits and that any limits to be imposed by the Commission will not cause price discovery in the commodity to shift to trading on the foreign boards of trade." CEA section 4a(a)(2)(C).

(iv) to ensure that the price discovery function of the underlying market is not disrupted.[11]

Second, the Commission must promulgate CEA section 4a(a)(2) position limits "[i]n accordance with the "standards" of CEA section 4a(a)(1).[12]

Finally, and most importantly for NGSA members, while Congress closed the regulatory gap concerning establishing position limits on swaps markets in addition to futures markets, nothing in Dodd-Frank modified longstanding statutory directives that the Commission establish position limits that are "appropriate" and that are "necessary" to curb "excessive" speculation, while, at the same time, requiring the Commission not to apply such limits "to transactions or positions which are shown to be bona fide hedging transactions or positions as such terms shall be defined by the Commission by rule, regulation, or order consistent with the purposes of this chapter."[13] Consistent with this, CEA section 4a(c)(2) directs the Commission to define ("the Commission shall define") "what constitutes" a BFH under the statutory definition of a BFH. The three statutory criteria for a BFH are as follows:

1) "Temporary Substitute" criterion: that the BFH "represents a substitute for transactions made or to be made or positions taken or to be taken at a later time in a physical marketing channel."
2) "Economically Appropriate" criterion: that the BFH "is economically appropriate to the reduction of risks in the conduct and management of a commercial enterprise."
3) "Change in Value" criterion: that the BFH "arises from the potential change in the value of— (I) assets that a person owns, produces, manufactures, processes, or merchandises or anticipates owning, producing, manufacturing, processing, or merchandising; (II) liabilities that a person owns or anticipates incurring; or (III) services that a person provides, purchases, or anticipates providing or purchasing."

We note also that promoting "sound risk management" is also a core policy goal under the CEA.[14] There is a direct link between promoting "sound risk management" and the BFH exemption. As the Commission's foremost advocate for speculative position limits, Commissioner Bart Chilton has notably stated: the Commission's speculative position limits regime should "encourage and not unduly complicate prudent commercial risk management practices."[15]

[11] CEA section 4a(a)(3)(B).

[12] The Commission interprets the "standards" of CEA section 4a(a)(1) as consisting of "the aggregation standard and the flexibility standard of CEA section 4a(a)(1)." 2013 NOPR at 75,684.

[13] CEA § 4a(c)(1), 7 U.S.C. § 6a(c)(1).

[14] CEA § 15(a)(2)(D).

[15] Statement of Commissioner Chilton, The End-User Bill of Rights, Apr. 3, 2013, http://www.cftc.gov/PressRoom/SpeechesTestimony/chiltonstatement040313.

III. Proposed Bona Fide Hedge Exemption Comments

A. The Commission should preserve the availability of and process for seeking a non-enumerated BFH

In establishing rules on BFH exemptions to position limits, NGSA urges the Commission to be cognizant of the goal it set for itself in 1977 when it proposed and finalized the definition of "bona fide hedging" that has been used until today (and is now largely codified in CEA section 4a(c)(2)), which is to:

> increase commercial utilization of futures markets for the purpose of hedging by allowing additional exemptions from the Commission's limits on transactions and positions. It is also intended to encourage increased commercial participation through recognition of a broad range of current risk shifting uses of futures markets.[16]

Consistent with that goal, NGSA recommends an alternative to the proposed exclusion of non-enumerated BFH from the BFH exemption: preserving the availability of a non-enumerated BFH exemption. To effectuate that goal, the Commission's rules should (1) provide for "non-enumerated" cases as currently provided in 17 CFR section 1.3(z)(3), and (2) set forth a process similar to current section 1.47 of Commission rules, albeit updated to reflect the fact that industries other than those transacting the nine legacy agricultural contracts have risk management practices that should be given appropriate consideration. Accordingly, the revised 1.47-like process should be clear, time limited, and transparent. Our recommendation is supported by the following points:

1) The categorical exclusion of non-enumerated BFH from the scope of the BFH exemption exceeds the Commission's authority to "define" what conforms to the BFH definition.
2) The categorical exclusion of non-enumerated BFH from the scope of the BFH exemption is an impermissible departure from current and historic Commission rules and designated contract market ("DCM") rules.
3) The costs to comply with a new BFH exemption that categorically excludes non-enumerated BFH are substantial.
4) The process to request exemptive relief for a non-enumerated BFH under section 4a(a)(7) of the CEA is inadequate and should be supplemented with a clear, time-limited, and transparent process for Commission approval of a "non-enumerated" hedge.

These points are discussed in more detail below.

1. The categorical exclusion of non-enumerated BFH from the scope of the BFH exemption exceeds the Commission's authority to "define" what qualifies as a bona fide hedge

[16] Definition of Bona Fide Hedging and Related Reporting Requirements, 78 Fed. Reg. 42,748 at 42,748 (Aug. 24, 1977) ("1977 Bona Fide Hedge Rule").

In the Commission's proposed definition of "bona fide hedge" in proposed rule 150.1, the Commission repeats the statutory definition of BFH with one important additional criterion, namely, the "Enumerated" criterion, which requires that a BFH be specifically "enumerated."[17] The Commission then enumerates the specific hedges that qualify as BFH and therefore the BFH exemption from speculative position limits.[18]

The Commission, however, may not interpret the statute in a way that allows it to categorically exclude certain transactions that conform to the CEA section 4a(c)(2) definition of BFH, i.e., a non-enumerated BFH. In limiting the Commission's discretion to define BFH in CEA section 4a(a)(2), Congress did so with the intention that the Commission "not make hedging so costly it becomes prohibitively expensive for end users to manage risk."[19] CEA section 4a(c)(2) does not direct the Commission to define *what is* a BFH. Rather, CEA section 4a(c)(2) directs the Commission to define ("the Commission shall define") "*what constitutes*" a BFH under the statutory definition of a BFH.[20] Congress therefore gave the Commission the discretion to define what transactions *conform to* the three BFH criteria that comprise the statutory definition of BFH, but not to narrow the definition so that it is inconsistent with the statutory definition. Consistent with Congressional members' stated intent, Congress did not provide the Commission discretion to invent a new definition of BFH or restrict or otherwise discard the statutory BFH definition or parts of it.

Limiting the statutory, CEA section 4a(c)(2) definition of BFH, however, is exactly what the Commission is proposing to do. The proposed section 150.1 definition of a BFH at paragraph (2)(i)(D) provides that all BFH positions must be "enumerated," in addition to meeting the three statutory criteria discussed in section II.B above.

CEA section 4a(c)(1) prohibits the Commission from applying *speculative* position limits on the bona fide hedging positions of any trader: "No rule, regulation, or order issued under subsection (a) of this section shall apply to transactions or positions which are shown to be bona

[17] Note that the statutory definition of a "bona fide hedge" in CEA section 4a(c)(2) is largely the same as the Commission's historic "general definition of bona fide hedging" adopted in the 1977 rulemakings and codified in 17 CFR 1.3(z)(1). The main difference is the Temporary Substitute criterion (the stricken word indicating a term dropped in the CEA section 4a(c)(2): the BFH "~~normally~~ represents a substitute for transactions made or to be made or positions taken or to be taken at a later time in a physical marketing channel." That change, however, does not modify the application of bona-fide hedge to commercial market participants using derivatives to hedge.

[18] Proposed rule 150.1 also proposed an "incidental test" that is not part of the statutory BFH definition in CEA section 4a(c)(2), i.e., that the risks offset by a derivative hedging position must arise from commercial cash market activities." While the Commission states that it believes this requirement "is also embodied in the economically appropriate test," 78 Fed. Reg. at 75,707, it is unclear what legal or policy basis justifies this addition, or why it is needed. To the extent that the "incidental test" adds any additional requirements beyond those in the statute, then the Commission may not include such a requirement because it exceeds its authority to define "bona fide hedging transaction or position" and is not adequate justified or explained by the Commission

[19] Letter from Sen. Christopher Dodd and Sen. Blanche Lincoln to Rep. Barney Frank and Rep. Colin Peterson, (June 30, 2010).

[20] The language introducing CEA section 4a(c)(2)'s BFH definition provides "[f]or the purposes of implementation of [position limits on futures positions], the Commission shall define what constitutes a bona fide hedging transaction or position as a transaction or position that-" meet the three criteria discussed in section II.B above. (emphasis added).

fide hedging transactions[.]"[21] Since Congress has given a definition of BFH for the Commission to use at CEA section 4a(c)(2) that is inclusive of non-enumerated BFH, the Commission does not have the statutory authority to restrict a person's non-enumerated BFH position. The Commission's proposal offers no reasoned explanation for exceeding the authority granted under CEA 4a(c)(2), and is an arbitrary and capricious restriction on bona fide hedgers.

2. The categorical exclusion of non-enumerated BFH from the scope of the BFH exemption is an impermissible departure from current Commission and DCM rules, and the proposal should reinstate the current position limit exemption structure

Under the current federal position limit regime, which applies to nine legacy agricultural futures contracts, an entity seeking a BFH exemption needs to (1) meet the general hedge definition in rule 1.3(z)(1), or (2) fit within one of the enumerated hedge exemptions in rule 1.3(z)(2), or, if it does not meet one of the enumerated hedges, apply for a non-enumerated hedge under the procedures set forth in 17 CFR 1.47. Unless notified otherwise by the Commission, an initial claim for a non-enumerated BFH exemption would be deemed approved after 30 days under 17 CFR 1.47(a)(2). For BFH applications other than for the nine legacy agricultural futures contracts, if a designated contract market ("DCM") sets a limit on a contract, a BFH request is made under Commission regulation 1.3(z)(1) – the Commission's *general definition* of BFH.[22] As to limits set by exchanges, current rule 150.5(d) mandates that exchanges provide for bona-fide exemptions "in accordance with § *1.3(z)(1)* [the general hedge definition] of this chapter."[23]

Thus, current Commission and DCM rules permit position limit exemptions for hedges that pass the *general* BFH definition. The Commission should revise its proposal to maintain this current structure because it serves the twin statutory goals of exempting bona fide hedgers from position limits and instructing the Commission to define "bona fide hedge" under the general hedge definition. Now that the Commission proposes to expand the list of federal position limits to additional commodities and products, thereby expanding the need for bona fide hedge exemptions, utilizing the current, longstanding exemption structure is even more important. The Commission therefore should (1) provide for a transparent and clear process built on section 1.47 for approval of non-enumerated hedges and (2) revise proposed section 150.5 to conform with the current section 150.5(d) and clarify that exchanges and SEFs provide for bona fide hedge exemptions under the general hedge definition in CEA section 4a(c)(2).

Ever since the 1977 rules, the list of enumerated hedge transactions, which applied only to nine legacy agricultural contracts subject to position limits, was not intended to be an exclusive list of BFH exemptions, but rather provided an efficient process for capturing common BFH transactions while at the same time allowing for approval of non-enumerated hedges. In the 1977 rulemaking proposing the 1.3(z) BFH definition, the Commission made two points

[21] CEA section 4a(c)(1).

[22] See CME Rulebook, Chapter 5, at 559.A. ("The Market Regulation Department may grant exemptions from position limits for bona fide hedge positions as defined by CFTC Regulation §1.3(z)(1).")

[23] 17 CFR § 150.5(d) (emphasis added).

particularly relevant to considering the historical context giving rise to the historic enumerated and non-enumerated hedge rules. First, the list of "enumerated" BFH (in 17 CFR 1.3(z)(2)) were those transactions that conformed to the "general definition" of BFH (in 17 CFR 1.3(z)(1)) "*without further consideration as to the particulars of the case*."[24] Second, the "non-enumerated" BFH (in 17 CFR 1.3(z)(3)) were those transactions that a market participant could demonstrate "evidence that such transactions meet the requirements of" the general definition of BFH.[25] The purpose of the provisions relating to "non-enumerated" BFH was "to provide flexibility in [the] application of the general definition and to avoid an extensive specialized listing of enumerated bona fide hedging transactions."[26]

In its final 1977 rule, the Commission agreed with commenters that noted that the enumerated transactions listed in 1.3(z)(2) would be "deficient for certain commodities where the Commission currently has no speculative limits."[27] Although acknowledging this possibility, the Commission explained that it "does not believe that it is necessary to enumerate transactions and positions which would be considered bona fide hedging in markets where it currently has no speculative limits."[28] Obviously, once it expands speculative position limits to new markets, the Commission would need to consider expanding the list of enumerated hedges accordingly, that, along with a process for approval of a non-enumerated hedge, would better reflect the expanded scope of position limits and the concomitant expansion of BFH-qualifying hedging activities. The final 1977 rules also emphasized the purpose of the Commission's bona fide hedging exemption: "to increase commercial utilization of futures markets for the purpose of hedging by allowing additional exemptions [from speculative position limits]"[29] and to "increase[] commercial participation of a broad range of current risk shifting uses of futures markets."[30]

Commission precedent thus establishes that the list of enumerated hedge transactions applied to federal limits was never intended to constrain the types of hedge transactions that qualify under the general BFH definition. Rather, enumerated hedges provide a means for fitting common hedge activity into the general BFH definition. At no time has the Commission ever sought to require that otherwise risk reducing BFH positions fall within a list of permissible hedge exemptions.

In stark contrast to the current rules, the 2013 NOPR categorically excludes non-enumerated hedges as BFH transactions (except under the limited and cumbersome exemption process discussed below). It does so despite the fact that the Commission proposes to significantly expand the federal limits to other commodities such as natural gas, which necessarily expands the types of BFH activities that may require exemptions. The Commission

[24] Bona Fide Hedging Transactions or Positions, 42 Fed. Reg. 14,832 (Mar. 16, 1977) (emphasis added).

[25] Id. at 14,833.

[26] Id.

[27] 1977 Bona Fide Hedge Rule, 42 Fed. Reg. at 42,750.

[28] Id.

[29] 42 Fed. Reg. at 42,748.

[30] Id.

does not offer any reasoned explanation for radically departing from current Commission rules and policy, particularly in light of a significant expansion of the federal rules to new products and industries. Simply put, Commission precedent does not support doing away with non-enumerated hedges. It is axiomatic that an agency must reasonably explain departures from past policy in its rulemakings in order to pass the standards of the Administrative Procedure Act prohibiting arbitrary and capricious rulemakings.[31]

NGSA respectfully submits that there is no justified reason to narrow the current policy as applied to BFH exemptions – in fact the expanded list of covered commodities would argue against such a narrowing. If the Commission wants to include a list of enumerated hedges, consistent with its longstanding precedent it should clarify that the list is not exclusive and merely provides for BFH determinations "*without further consideration as to the particulars of the case*." At a minimum, the Commission should establish an efficient process for seeking and approving a non-enumerated hedge in a reasonable time frame similar to current 17 CFR sections 1.3(z)(3) and 1.47 along with transparency and reconsideration rights as discussed below.

In addition, as proposed, revised rule 150.5(a)(2), which would modify current rule 150.5(d), is ambiguous in that it requires exchange-set limits to conform to the hedge definition in rule 150.1, which includes the enumerated hedges. But since the Commission has not reviewed, discussed, or considered any hedge activities with respect to non-referenced contracts, it cannot impose the list of enumerated hedges on non-referenced contracts (nor, as we argue, should it do so for referenced contracts). To correct this ambiguity, we recommend, at a minimum, that the Commission revise proposed rule 150.5(a)(2) as follows:

> Any hedge exemption rules adopted by a designated contract markets or a swap execution facility that is a trading facility must conform to the definition of bona fide hedging position in § 150.1 <u>for referenced contracts, and section 4a(c)(2) of the Act for non-referenced contracts.</u>

3. The process to request exemptive relief for a non-enumerated BFH is inadequate and should be replaced with a clear, time-limited, and transparent non-enumerated exemption process

Unlike the current rule 1.3(z)(3) and 1.47 process, a process that has existed since 1977 (and for a good reason, as noted above), the Commission's proposal does not afford a BFH applicant the right to request a non-enumerated hedge and obtain approval in a time-limited manner upon a showing that it meets the general BFH definition under 1.3(z)(1). Rather, under proposed 150.3(e)(2), parties seeking an exemption for a non-enumerated BFH may request "[e]xemptive relief under section 4a(a)(7) of the Act" (which relates to general exemptions from position limits). It is unclear whether the Commission would grant such relief through notice and comment procedures or not. If it does, then the delays caused by that process would increase the uncertainty and costs for NGSA members to manage their commercial risks, and this

[31] *See Motor Vehicle Mfrs. Assn. of United States, Inc. v. State Farm Mut. Automobile Ins. Co.*, 463 U. S. 29, 57 (an agency changing its policy must articulate a reasoned analysis for its change).

exemptive relief is not a reasonable substitute for a clear, time limited, and transparent non-enumerated hedge process.[32]

Furthermore, NGSA members are operating with the assumption that non-enumerated BFH would not qualify for exemptive relief as a general rule because of the Commission's restrictive view of the BFH exemption, as described above. The Commission has not described what kind of facts would be sufficient to obtain these exemptions, i.e., when a non-enumerated BFH is adequately "risk-reducing" in the Commission's view.

We therefore recommend that the Commission preserve a non-enumerated BFH exemption and a process to obtain it. Section 1.47 is a good model; however, due to the expanded list of commodities and hedge activities affected by the federal limits, the process should be clear and allow for meaningful hedge exemptions. To maximize transparency and to minimize uncertainty and the burdens on the Commission and market participants, we recommend that the non-enumerated exemption request process: (1) require Commission action within 30 days or be deemed to be approved; (2) provide for an expedited, one-spot month approval process that provisionally approves the request within five business days (to allow for hedges in the current spot month); (3) provide for a right of reconsideration; and (4) require all approvals and disapprovals be posted on the Commission's website, so long as the requesting party may seek confidentiality and the request, the approval/denial, and the fact pattern may be sufficiently anonymized so that confidential information is not disclosed.

If the Commission declines to provide for a non-enumerated process, NGSA recommends that the Commission provide legal certainty that a 150.3(e)(2) would be available and to provide some guidance on under what conditions and what timeline such relief would be available. This would reduce the uncertainty and therefore costs and constraints on NGSA members' risk management activities posed by proposed 150.3(e)(2). The Commission should explain what factors it intends to utilize in granting 150.3(e)(2) relief and hypothetical examples of positions that would qualify for it so long as it adheres to the general hedge definition Congress set forth in CEA section 4a(c)(2). In addition, if the Commission determines to adopt proposed 150.3(e)(2) as proposed, we recommend that the Commission clarify that such relief may be granted expeditiously, without the need for rulemaking. We note that CEA section 4a(a)(7) allows the Commission to grant relief "by rule, regulation, *or order*." (emphasis added). We also ask that the Commission provide for some period, e.g., five business days, after which a request for 150.3(e)(2) would be deemed approved.

4. The compliance costs associated with the Commission's proposed restrictions on bona hide hedge exemptions are substantial and unnecessary to curb excessive speculation

[32] The proposed amendments to § 150.3 also provide that a BFH applicant may seek an interpretative letter from Commission staff under rule 140.99. Such part 140.99 interpretive letters are available to parties regardless of proposed section 150.3, and so it is unclear how this addition adds anything for entities affected by Commission rules. Regardless, section 140.99 is not a reasonable substitute for a clear and transparent 1.47-like process. First, a response under 140.99 is not time limited. Second, a 140.99 interpretive letter does not bind the Commission and may not adequately serve the statutory requirement to exempt bona fide hedgers from position limits

The Commission does not consider the costs of requiring BFH applicants to fit their hedge strategies within one of the enumerated hedges listed in section 150.1. Indeed, it admits as much when it notes that, with respect to hedgers seeking section 150.3(e) relief for hedges outside of the enumerated hedges:

> The Commission is unable to ascertain at this time the number of participants affected by these proposed regulations. The Commission notes, however, that a decision to incur the costs inherent in seeking relief is voluntary.[33]

NGSA respectfully disagrees that costs of seeking relief from the enumerated hedges are merely "voluntary" and in fact the Commission's proposal imposes substantial direct costs (the exemption filing) and indirect costs (altering risk reducing hedges to fit within an enumerated hedge instead of the general hedge definition) on the very market participants that CEA section 4(a) carves out from the position limits, namely bona fide hedgers. Many NGSA members have spot month positions in referenced contracts near or in excess of DCM speculative position limits. These positions are maintained in reliance on the general BFH exemption currently codified in Commission rule 1.3(z)(1). These positions could be maintained in reliance on the BFH definition provided under the CEA section 4a(c)(2) as well. Generally speaking, these BFH definitions mirror the risk management transactions NGSA members engage in and therefore there is a significant overlap between the 1.3(z)(1) and CEA 4a(c)(2) definitions of BFH and NGSA members' risk management practices. This makes compliance with DCM rules and would make compliance with a rule based on CEA section 4a(c)(2) manageable.

The Commission's proposal to limit BFH exemptions to a list of enumerated hedges imposes substantial costs on NGSA members relative to the DCM-administered status quo. These most foreseeable among these costs include:

1) *Compliance costs*. Because there is not a significant overlap between NGSA members' proven and effective risk management practices and the Commission's narrow BFH definition, NGSA members with positions near a position limit would have to create entirely new systems to track transactions and positions that qualify under the Commission's narrow BFH definition. This is especially true because of the proposed position limits will be effective on an intra-day basis. Intraday limits have been in place for some time for spot month limits, but not for any and all month limits. Moreover, ensuring compliance will become much more difficult now due to the aggregation of more affiliates (including non-US affiliates), and the inclusion of OTC products under the limits. Mechanisms to ensure compliance will by necessity include costly manual components, as well as expensive technology.

2) *Costs related to position capacity*. Some members would not be able to or would run a significant risk of not being able to claim BFH exemptions for their risk management positions in excess of speculative position limits, despite the fact that such activities are risk-reducing hedge strategies that would qualify under the general hedge definition in CEA section 4a(c)(2). This means that firms may need to forego risk management activities. The extent of these costs

[33] 78 Fed. Reg. at 75,773.

is also related to spot-month position limit levels themselves, which are discussed in section V.A below.

3) *Liquidity costs*. Because the proposed BFH definition excludes non-enumerated BFH positions, including certain hedges related to anticipated transactions in natural gas, NGSA members would face direct and indirect increased costs due to the impact on liquidity. The direct liquidity costs relate to our members' counterparties' decreased willingness to provide non-enumerated BFH swaps, since these swaps would not be eligible for the proposed pass-through swap exemption in paragraph (2)(ii)(B) of the Commission's BFH definition relative to what is provided for under CEA section 4a(c)(2)(B). The indirect liquidity costs arise from decreased liquidity in certain products and geographic markets due to parties forgoing risk reducing activities that may not qualify under the list of enumerated transactions, particularly as related to the prompt month NYMEX Henry Hub Natural Gas contract (since the BFH exemption is most restricted in that contract during the "spot month").

4) *Market inefficiencies and transaction costs.* Under the Commission proposed BFH definition, hedges of fixed-price purchases and sales can be maintained through the spot month in the physical-delivery futures contract. The Commission's proposed approach to the BFH exemption and its apparent skepticism of the economic utility of hedging floating-price risks creates a regulatory bias in the market that would an incentive to market participants to negotiate fixed-price purchase and sales contracts. This regulatory bias conflicts with sound contracting and risk management activities that have long served the natural gas market, particularly where different commercial market participants have different risk profiles and contract based on their commercial needs. The commission's proposal would introduce time risk and lower correlations. The less perfect hedges would result in residual risk that imposes additional costs. Those costs would ultimately be reflected in the prices paid by customers.

We note also that promoting "sound risk management" is a factor the Commission is required to consider in promulgating new regulations under CEA section 15(a). We believe relative to the status quo or relative to a BFH exemption that encompasses enumerated and non-enumerated BFH, the Commission's proposed BFH exemption would have an adverse effect on sound risk management.

NGSA understands that part of the Commission's motivation for the categorical exclusion of non-enumerated BFH may have to do with the Commission's resource constraints. We acknowledge that some non-enumerated BFH require a close understanding of commodity risk management and validating whether these claimed non-enumerated BFH positions conform to the CEA section 4a(c)(2) BFH definition could drain limited Commission labor and technology resources from broader oversight tasks. As noted in the prior section, however, a transparent and publically posted process should minimize burdens on Commission resources.

In any event, we recommend that the Commission leverage DCM resources in order to effectuate a BFH policy that does not place artificial limitations on the ability of commercial hedgers to manage their risks. The Commission could require that a commercial firm claiming a non-enumerated BFH exemption submit their initial statement[34] to both the Commission and a DCM or SEF on which they have a reportable position.[35] The DCM or SEF could then preliminarily review and opine on the initial statement. While the Commission would not be bound in any way by the DCM or SEF determination, such a preliminary review could reduce the draw on Commission resources.

B. Interpretation of "economically appropriate" bona fide hedge criterion

1. The Commission's interpretation of the "economically appropriate" criterion should be clarified to accommodate the wide array of prudent commercial risk management practices

a) "Economically appropriate" bona fide hedging transaction or position criterion should be clarified

The Commission should reconsider its guidance on the "economically appropriate" criterion of the bona fide hedging position exemption and instead acknowledge the complexities associated with managing commercial enterprises including natural gas market participants. The Commission suggests that in order for a "position to be economically appropriate to the reduction of risks in the conduct and management of a commercial enterprise, the enterprise generally should take into account all inventory or products that the enterprise owns or controls, or has contracted for purchase or sale at a fixed price."[36]

That approach is too limited and fails to reflect the fact that the risks companies face are seldom internally netted on a one-to-one basis. A commercial enterprise may have price risks arising from activities in different commodities, different grades of commodities, different geographic locations, different processing and production facilities, different availability of transportation infrastructure, among others. Depending on the circumstances, it may be economically appropriate to transform one form of price risk into another form of price risk that is more easily managed, e.g., to convert fixed-price risk to floating-price risk or vice-versa, or to convert unpriced risk to floating average price risk. Under certain circumstances, a hedge transaction may shift risk (without increasing overall risk) from one business line to another business line. For example, a natural gas producer may decide not to hedge any price risk associated with its current production and marketing of that production, but yet decide to hedge a projected new production project that has yet to produce gas if, for example, it needs to lock in a profit stream to allow it to use debt financing to fund the necessary infrastructure projects. The Commission's proposal wholly overlooks real world commercial risks and instead would disallow hedge exemptions if somewhere else in the company there may be a risk offset.

Footnote 450 of the Commission's proposal suggests that "whether it is economically appropriate for one entity to offset the cash market risk of an affiliate depends, in part, upon that

[34] See 17 CFR 1.47(b).

[35] See 17 CFR 15.03(b).

[36] 78 Fed. Reg. at 75,709.

entity's ownership interest in the affiliate."[37] NGSA disagrees that ownership percentage should dictate whether a hedge is "economically appropriate." Many natural gas projects are joint ventures where a majority or even minority equity interest owner may be responsible for marketing the gas and for managing the venture's price risks.[38] In those circumstances, it may be economically appropriate for the joint venture's physical commodities price risk to be managed in whole (not by pro rata equity share) by the enterprise whose affiliate is responsible for marketing production.

When considering what types of hedges are "economically appropriate" it is critical that the Commission consider what risks are being hedged. This raises a very problematic potential issue: The Commission interprets the "economically appropriate" criterion to allow gross hedging, i.e., hedging gross physical price risk exposures rather than net price risk exposures, but apparently only "when net cash positions do not measure total risk exposure due to differences in the timing of cash commitments, the location of stocks, and differences in grades or types of the cash commodity being hedged."[39] In the proposed Appendix C, the Commission provides an example of a hedge of a net cash position of two million bushels of unsold corn after deducting fixed-price sales from inventories.[40] While under that scenario a distinct net unsold inventory hedge may have been appropriate in that circumstance, there are circumstances where reducing price risk in one portion of a physical portfolio may be economically appropriate.

The Commission has never undertaken a restrictive reading of its "economically appropriate" criterion. The Commission staff members involved in formulating the bona fide hedging position definition in 1.3(z) and now CEA section 4a(c)(2) explained the meaning of the "economically appropriate" test, quoting Commission rule 36.3(c) (1984):

> This concept [of economically appropriateness] has been conveyed by the terms 'for other than speculative purposes by producers, processors, merchants or commercial users engaged in handling or utilizing the commodity…"[41]

We caution that the Commission should not adopt an overly restrictive interpretation of "economically appropriate." It is far too broad to restrict a commercial firm's ability and freedom to determine a risk management strategy appropriate to its business by forcing companies to look to all of their business lines. If the Commission is concerned with specific commercial risk management practices, it should specifically identify these types of activities, analyze them under CEA section 4a and the general purposes of the CEA, propose to interpret them as economically inappropriate, and then subject the proposed interpretation to notice and comment. We note that the Volcker rule's hedge exemption did not adopt a restrictive hedging standard, but did present instances where the hedge exemption would be inapplicable. Such an

[37] 78 Fed. Reg. at 75,736 at fn. 450.

[38] To clarify, the enterprise marketing the production would also "control" the venture's trading.

[39] 2013 NOPR at 75,709.

[40] Id. at 75,835.

[41] The CFTC's Hedging Definition Development and Contemporary Issues, Blake Imel, Ronald Hobson, and Paula Tosini, Working Paper Series #CSFM-119, Oct. 1985 citing 17 CFR 33.6(c) (1984).

approach may be instructive to the Commission as it considers how to finalize its interpretation of the "economically appropriate" BFH criterion.[42]

If the Commission properly interprets and defines "economically appropriate," the uncertainties, costs and administrative burden of maintaining a system of enumerated BFH categories can be reduced or eliminated. The statute does not require that a BFH fit within enumerated categories. The Commission has demonstrated neither that a system of enumerated categories is necessary nor that it is actually workable. The current approach to judging the eligibility for BFHs set out in the CEA along with a non-enumerated exemption request process has worked well to govern hedge exemptions, and we believe that such a system, with added transparency to accommodate the expanded list of federal position limits, can readily accommodate hedge exemptions related to the new limits.

NGSA recommends that the Commission set criteria that delineate "economically appropriate" to give comfort that hedges qualifying on this basis (without necessarily falling in one of the enumerated categories) are indeed risk reducing. Companies availing themselves of exemptions on an "economically appropriate" basis would need to be able to demonstrate that the hedges that they assert are bone fide, indeed fit within those criteria.

Defining these criteria need not be a difficult practice, the Commission need only look to CEA section 15(a)(2)(D), which provides that "sound risk management" is a core policy. NGSA believes that sound risk management practices in the energy industry are those used to manage three types of exposure: (1) fixed price exposure (either physical or financial) long (including inventory) or short; (2) spread exposure – basis, time spread, cross-commodity; or (3) option parameter exposure – volatility (Vega), time (Theta), etc. This is status quo, accepted prudent risk management practice. Our belief is that if a company can show that a hedge fits into one of these three categories, it is economically appropriate, and the analysis should end there.

C. The Commission's preamble guidance does not adequately apply the "bona fide hedge" definition to hedges of certain physical, and in particular, energy commodity risks

The Commission seeks to exclude all non-enumerated BFH from the BFH exemption. NGSA is not aware of any Congressional concerns relating to the current standards applied by DCMs or the Commission when granting BFH exemptions related to hedges of physical commodity risk. As discussed in section II.A above, Amaranth and the Hunt Brothers were pure speculators with no physical commodity hedging need. Neither Amaranth nor the Hunt Brothers used, let alone abused a BFH exemption.

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[42] The Volcker rule's hedge exemption provides that "generalized risks" based on "non-position-specific modeling or other considerations" cannot serve as the basis for the hedge exemption. Prohibitions on Proprietary Trading and Certain Relationships with Hedge Funds and Private Equity Funds, Dec. 10, 2013, pp. 345-346, available at http://www.sec.gov/rules/final/2013/bhca-1.pdf. Moreover, general market movements or broad economic conditions, profit in the case of a general economic downturn, counterbalance revenue declines generally, or otherwise arbitraging market imbalances unrelated to the risks resulting from the positions lawfully held by the banking entity are further examples of transactions that would not conform to the Volcker rule's hedge exemption either. *See id*.

Nor, as discussed in sections II.B and III.A.1 above, has Congress indicated any desire that the Commission narrow the availability of the BFH exemption for hedges of physical commodity price risk. As discussed in III.A.1 above, Congress went out of its way to circumscribe the Commission's ability to define the term BFH.

The Commission has based its proposal on a number of arguments; some apply to non-enumerated BFH generally and others apply to specific non-enumerated BFH. We begin with two of the arguments of general applicability.

First, the Commission argues that "historically, there have been relatively few positions held in excess (and those few not greatly in excess) of the spot month limits."[43] We believe the Commission made this argument in error. 22 pages from where the assertion that only a "few" positions would be in excess of the proposed spot month limits, the Commission displays a chart that shows that in NYMEX Henry Hub Natural Gas alone 61 companies would have positions in excess of the proposed spot month limits.[44] NGSA members are included among these "few" 61 companies and all of them currently rely on DCM-administered BFH exemptions to maintain compliance with DCM spot month limits. They would be unable to do so because many of positions they maintain are hedged with positions that do not fit in an enumerated category.

Second, the Commission argues "almost all [non-enumerated BFH exemptions] were for risk management of swap positions related to the agricultural commodities subject to federal position limits."[45] This second argument is not relevant to energy markets. The Commission has not witnessed the widespread use of the non-enumerated provisions of the BFH exemption because it has only administered a position limits for the nine "legacy" agricultural commodities covered by the 2013 proposal – not the other 19 commodities, including natural gas.

We note that the enumerated BFH categories the Commission borrows from its 1977 bona fide hedging rulemaking were not crafted with all commodity markets in mind and indeed are "deficient" for other commodity markets.[46] In 1977 the Commission took note of comments suggesting that the "specific transactions and positions enumerated as bona fide hedging…. would be deficient for certain commodities where the Commission currently has no speculative limits."[47] The Commission responded that it "does not believe that it is necessary to enumerate transactions…which would be considered bona fide hedging in markets where it currently has no speculative limits."[48]

1. Categories of hedges that have been inappropriately denied BFH status

[43] 2013 NOPR 75,710.

[44] Id. at 75,732.

[45] Id. at 75,710.

[46] 42 Fed. Reg. at 42,748.

[47] Id.

[48] Id.

The Commission also makes the following arguments in relation to specific non-enumerated BFH particularly relevant to NGSA members. We address them in the following paragraphs:

- *Short anticipatory hedge positions in the spot month*

With respect to the restriction on short anticipatory hedge positions, the Commission states that it "did not believe that persons who do not possess or do not have a commercial need for the commodity for future delivery would normally wish to participate in the delivery process."[49] NGSA points out that the "long-held policy views," first, as discussed above, only related to "legacy" agricultural commodities. Secondly, even when the Commission first expressed those views in 1977, it did not categorically exclude the availability of the BFH exemption for cross-commodity hedges as it has done in the 2013 NOPR.[50] In addition, with respect to short anticipatory hedge positions there are many instances in which a NGSA member would possess the natural gas on which it based an anticipated production hedge.

For example, NGSA members routinely hedge natural gas production expected or "anticipated" to be produced during the spot month or delivery period by selling NYMEX Henry Hub Natural Gas ("NG") contracts. Future production hedged with forward contracts, with the passage of time, eventually becomes current month production hedged with spot month contracts. There is no commercial rationale to disassociate them by forcing proper hedges beyond the spot month. Allowing NGSA members to continue to make delivery on a NG anticipated production hedge provides a policy benefit as well: it provides natural gas producers the ability to make delivery on production on the NG contract when the NG contract price is trading at higher than the cash market price. This has the effect of promoting cash market-futures market convergence, promoting therefore the price discovery function of the underlying physical-delivery futures market.[51] Conversely, denying exemptions to companies that have short non-enumerated BFH positions has a strong potential to "disrupt" the price discovery function of the NG market.

The Commission has not pointed to any deficiencies with the current protections for the NG physical-delivery futures contract month's delivery period that warrant a categorical denial of BFH treatment of spot month anticipated production and other non-enumerated hedges.[52] As commercial users of the NG market, we have confidence in the DCMs' ability to ensure an orderly delivery process and we are unaware of any disruptions warranting a more protective

[49] 2013 NOPR at 75,710.

[50] 42 Fed. Reg. at 42,749-42,750 ("persons wishing to exceed [position] limits during the five last trading days may submit materials supporting classification of the position as bona fide hedging pursuant to [17 CFR 1.3(z)(3)].").

[51] CEA section 4a(3)(B)(iv) (in establishing a position limits regime the Commission is "to ensure that the price discovery function of the underlying market is not disrupted.").

[52] See e.g., CME Rulebook, Chapter 7B, at 716, available at http://www.cmegroup.com/rulebook/NYMEX/1/7B.pdf ("Prior to the last day of trading in a physically delivered contract, each clearing member shall be responsible for assessing the account owner's ability to make or take delivery for each account on its books with open positions in the expiring contract. Absent satisfactory information from the account owner, the clearing member is responsible for ensuring that the open positions are liquidated in an orderly manner prior to the expiration of trading.").

approach to the delivery process, particularly when the protections the Commission is proposing to impose would reduce commercial participation in the spot month and delivery process.

- *Anticipated revenues associated with owned or leased merchandising capacity*

With respect to hedges of anticipated revenues associated with owned or leased merchandising capacity, the Commission states that it "doubt[s] that such a position generally will meet the economically appropriate test…."[53] The Commission therefore proposes to exclude an exemption for "anticipated merchandising hedges" previously included in vacated rule 151.5(a)(2)(v). We disagree with the Commission's analysis and believe that it misapplies the "economically appropriate" test with respect to anticipated hedging of storage capacity for the reasons we note below.

Many natural gas market participants hold contractual rights for natural gas storage capacity that is typically used to store natural gas during times of lower demand (summer) for later use during times of higher demand (winter). Market participants may lock in the spread between their anticipated injections or purchases and their anticipated withdrawals or sales with natural gas calendar spread hedges. To illustrate the need to hedge, consider a company that holds storage capacity rights ("the company"). In April, the company takes note of its unfilled capacity and considers the difference in NYMEX Henry Hub futures prices between the summer season (typically April – October) and the withdrawal season (typically November – March). Assume that on April 1, the June contract is trading at $4.00 per MMBtu, while the January contract is trading at $5.00 per MMBtu. The company has several options to consider. Thus, it may do any of the following:

1) Negotiate for the purchase of fixed price natural gas forward contracts in sufficient quantities to fill their capacity during the April – October injection season at the current price of $4.00, and sell winter NYMEX Henry Hub futures. If it manages to purchase sufficient quantities of physical forward gas at $4.00, all it needs to do is sell the winter NYMEX Henry Hub futures (and locational basis, if applicable) to lock in the $1.00 spread, which would be an allowed bona fide hedge under paragraph (4)(ii) of the proposed definition of BFH.

2) As an alternative, the company may buy the June Henry Hub futures contract at $4.00 per MMBtu, and sell the January contract at $5.00 per MMBtu (and locational basis, if applicable), i.e., establish their hedge in anticipation of the offsetting forward purchases of natural gas contracts to fill their capacity and thus immediately lock in the $1.00 spread. For the June physical injection, the company would then either buy monthly index gas or buy a monthly-daily index swap and buy daily gas at index. During the withdrawal month, the company may do the reverse (sell at monthly index or, more typically, sell an index swap and sell physical gas at daily index prices).

3) Do nothing and hope the favorable $1.00 spread is still available when the company begins to purchase natural gas for injection.

[53] 2013 NOPR at 75,718.

We commend the Commission for recognizing as an enumerated BFH the strategy in option 1, but in reality option 2 is often more practical, more typical, and more economically appropriate. For example, in reality, it is unrealistic to require a company to buy June physical gas in sufficient quantities at $4.00, and even if it could, such negotiations could take time and the $1.00 spread could narrow in the meantime. In that case, the more economically appropriate strategy is option 2, which allows the company to immediately lock in the spread and therefore reduce the risk to the company that the calendar spread would narrow.

Significantly, we believe that the Commission's analysis fundamentally misconstrues the risks to the company and in fact its proposed policy would add unnecessary risk to commercial firms. Contrary to the Commission's reasoning, the risk to the company is not just the "rents" paid for use of the facility.[54] In fact, there exists a risk that the spread will narrow and therefore prudent, and "economically appropriate," risk management practices have been developed and long utilized to hedge this risk – in fact derivative products have developed in ways that allow such risks to be hedged. Likewise, the analysis fails to recognize the fact that the economic value of a storage contract is the market value, which is a function of the calendar spread and the volatility of that spread, and that if the Commission forces companies to hedge only after purchasing gas, rather than in advance using derivatives, it actually would expose companies to loss in economic value of their storage contract. In addition, the analysis fails to consider that natural gas storage contracts limit injection and withdrawal rates based on the physical limitations of the facility and compressors. If the Commission were to allow a BFH exemption only after the company has purchased gas for injection, it would artificially constrain the ability of companies to appropriately manage the day-to-day physical injection and withdrawal limits and would in fact expose companies to significantly greater risks. The analysis also overlooks the fact that storage rents can be, and sometimes are, priced based on the market value of the spread (e.g., market-based storage facilities), and thus storage customers should be permitted to hedge the spread when they contract for the storage capacity.

The analysis also "doubts" that an anticipatory hedge of unfilled storage is "economically appropriate" because there may be a "difference in the anticipated supply and demand of a commodity on the different dates of the calendar month spread."[55] This argument also fails, particularly as applied to the natural gas industry. First, natural gas is injected into storage throughout the injection season to serve well understood peak demand periods applicable to the region, and this demand, particularly among residential and commercial customer classes, is relatively inelastic. Therefore, gas is injected into storage to serve both baseload demand and daily swing demand during these peak periods. Even under the Commission's reasoning, it would, at a minimum, be "economically appropriate" for a storage holder to engage in anticipated hedging of its baseload needs since those needs are reasonably expected to materialize (and, of course, we believe that hedging swing needs is likewise economically appropriate). Second, even if some of the demand does not materialize in the withdrawal month hedged, or even if daily swing volumes are not needed on a given low demand day in the

[54] See 78 Fed. Reg. at 75,718-19 (asserting that such a hedge may not be "economically appropriate" because the value fluctuations in the calendar spread will "likely" have low correlation to the rents on the unfilled storage).

[55] Id. at 75,719.

withdrawal period, the storage holder can use derivatives to roll the storage hedge forward to the next month as needed to line up the hedge to another withdrawal month, and, as noted above, can use monthly-daily index swaps to tailor the hedge to be "economically appropriate" on a daily withdrawal basis. In the natural gas industry, therefore, it is not accurate to claim that an anticipatory hedge of unfilled storage is economically inappropriate because there may be a "difference in the anticipated supply and demand" conditions on the different dates of the calendar spread. In short, the Commission has not justified why it would no longer approve a BFH exemption for a storage customer that seeks to hedge in anticipation of injecting gas into inventory. Commercial firms should continue to be allowed to engage in longstanding approaches to mitigate anticipated merchandising risks through the use of anticipatory merchandising hedges.

Finally, by limiting merchandisers' ability to hedge their legitimate anticipated transactions, the Commission also artificially moves transactions away from the cash market, and encourages forward contracts, which could have an adverse impact on liquidity and price discovery while not reducing excessive speculation or the likelihood of manipulation.[56] As noted above, the typical storage hedge involves locking in the spread with Henry Hub futures, locational basis, if applicable, and index swaps, which enables the company simply to buy gas in the daily market at index (or at a fixed price that it is reasonably sure will approximate the index price). The Commission's preferred hedge, however, would encourage bilateral negotiations for forward physical gas – and such transactions are not reported or included in a Platts or Argus price survey and hence the Commission in fact would inhibit price discovery.

For the reasons stated above, the Commission should not categorically exclude the anticipated merchandising hedge from qualifying for BFH exemptions. In fact, the Commission should, as it did in its last rulemaking, expressly include such a hedge as an enumerated BFH based on the same reasoning it offered previously.[57] At a minimum, the Commission should permit the company to apply for (and it should promptly approve) a non-enumerated BFH exemption for an entire injection and withdrawal year.

- *Anticipated merchandising*

In addition to the issues raised above regarding merchandising with storage assets, with respect to anticipated merchandising generally, the Commission argues that because the risk is anticipated, a hedging transaction "could not reduce this yet-to-be assumed risk" and therefore anticipated merchandising fails to meet the "Change in Value" criterion of the BFH definition.[58] We do not think that the Commission's analysis fully considers the implications of this guidance on the natural gas markets (or other energy markets for that matter). This guidance essentially

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[56] CEA section 4a(a)(3)(B).

[57] In its prior rules, now vacated, the Commission specifically included the anticipated merchandising hedge in the list of enumerated hedge transactions, and even included a "fact pattern" explaining why a grain merchandiser's hedge of a storage facility appropriately hedges the merchandiser's "risk that its unfilled storage capacity will not be utilized over th[e] period" of its hedge. The Commission, at that time, correctly identified the risk and correctly found that the calendar spread hedge met the general hedge definition. *See* 76 Fed. Reg. at 71,698.

[58] 2013 NOPR at 75,718 (quoting 76 Fed. Reg. at 71,646).

would curtail hedges of unsold physical positions despite the fact that market participants have long been able to minimize commercial risk by prudently hedging such risks. For the reasons noted below, the Commission cannot and should not categorically exclude anticipated merchandising from the definition of BFH.

First, the Commission *cannot* narrow the definition of BFH to exclude anticipated merchandising because to do so would contradict the CEA. CEA section 4a(c)(2)(A)(iii)'s "Change in Value" criterion explicitly covers "potential change[s] in value of…assets that a person … anticipates owning… or merchandising." The Commission therefore cannot claim that anticipated merchandising-related price risk does not conform to the "Change in Value" criterion because the "Change in Value" criterion explicitly includes anticipated merchandising-related price risk.

Second, the Commission *should not* narrow the definition of BFH to exclude anticipated merchandising because merchandising activities promote cash and futures market convergence and therefore the price discovery function of the physical-delivery futures market.[59] Many NGSA members both produce and merchandize natural gas. We often hedge anticipated merchandising-related price risks. As noted by the Commission in the 2013 NOPR:

> [T]he Commission has observed when a physical-delivery contract is trading at a price above prevailing cash market prices, commercials with inventory tend to sell contracts with the intent of making delivery, causing physical-delivery prices to converge to cash market prices. Similarly, the Commission has observed when a physical-delivery contract is trading at a price below prevailing cash market prices, commercials with a need for the commodity or merchants active in the cash market tend to buy the contract with the intent of taking delivery, causing physical-delivery prices to converge to cash market prices.[60]

Anticipated merchandising hedge positions promote the price discovery function of the underlying market by supporting merchandising activities that allow the movement of gas from the production areas to the consuming areas. The natural gas transportation system was built on the anticipated movement of gas, and shippers and transporters alike have risked billions of dollars to invest in such projects often based on the ability to hedge such projects in advance of the in-service date.

By limiting merchandisers' ability to hedge their legitimate anticipated transactions that conform to current 17 CFR 1.3(z) and CEA section 4a(c)(2), the Commission is proposing a regime that would have an adverse impact on price discovery while not reducing excessive speculation or the likelihood of manipulation.[61] Merchandising is the key to ensuring efficient supply chain operations, and therefore it minimizes midstream costs to the benefit of end users. There is no statutory or policy reason to treat cash market merchandising any differently from production or processing or any other commercial activity.

[59] See CEA section 4a(a)(3)(B)(iv).

[60] 2013 NOPR at 75,737 at footnote 463.

[61] CEA section 4a(a)(3)(B).

The Commission makes a number of arguments in support of imposing a restriction on specific anticipated merchandising non-enumerated BFH in natural gas and other non-"legacy" commodities. These arguments are presented and discussed below.

With respect to anticipated merchandising hedges of the floating-price risk of a purchase or sale contract when an offsetting floating-price sale or purchase contract has been entered into, the Commission believed that "a trader has not established a definite exposure to a value change when that trader has established only an unfixed price purchase or sales contract."[62] Moreover, the Commission argues, the intention behind the hedge could change when "changed conditions resulted in a change in intentions."[63]

NGSA disagrees with the argument that a floating-price purchase or sale that is anticipated to be offset by a floating-price sale or purchase does not establish a "definite exposure to a value change" for at least two reasons. First, as discussed above, price risk associated with anticipated merchandising activities are included within CEA section 4a(c)(2)(A)(iii)'s "Change in Value" criterion. Second, the risk reduction afforded by a BFH position in this scenario is demonstrable. Consider a scenario where a trader desires to enter into a floating-price forward natural gas sale with a Transco Zone 6 reference price. The trader is motivated to enter into the trade because of the Transco Zone 6 and Henry Hub locational differential and therefore "reasonably certain" (2011)[64] or "highly certain" (2013)[65] of later buying the equivalent amount of natural gas at index price at Henry Hub or a location that has prices closely correlated to Henry Hub.[66] The trader can do one of several things before offsetting the sales transaction, each of which affects the trader's risk profile:

1) Do nothing, in which case the trader bears locational basis floating-price risk between Transco Zone 6 and Henry Hub;
2) Offset the Transco Zone 6 leg of the transaction with a swap transaction, which would give the trader outright anticipated Henry Hub floating-price risk; or
3) Offset both the Transco Zone 6 floating-price risk and the anticipated Henry Hub floating-price risk.

If the trader is "reasonably certain" (2011)[67] or "highly certain" (2013)[68] that they are going to offset the Transco Zone 6 sale with a Henry Hub or Henry Hub-like purchase, then they bear the least price risk if they carry out the third option. The Commission is opining that only option 1, however, is "economically appropriate." We think option 1 is the most "economically appropriate" only when the trader is uncertain how it is going to source the Transco Zone 6 gas.

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[62] 2013 NOPR at 75,719.

[63] Id.

[64] 76 Fed. Reg. 71,646-71,647.

[65] 2013 NOPR at 75,714.

[66] For the sake of simplicity, we ignore transportation costs.

[67] 76 Fed. Reg. 71,646-71,647.

[68] 2013 NOPR at 75,714.

When a trader, as in the scenario above, is motivated to sell the Transco Zone 6 leg of the merchandising transaction because of the differential between the Transco Zone 6 and Henry Hub prices and is "reasonably" or "highly" certain of the offsetting Henry Hub or Henry Hub-like purchase, then the hedging strategy described in option 3 would be the most "economically appropriate" manner to reduce the risks associated with the anticipated merchandising activity. Option 3 would reflect standard natural gas industry hedging standards under the circumstances described above.

With respect to hedging binding, irrevocable fixed-price bids or offers, a common means by which utilities acquire natural gas, the Commission found that they represent a "tentative," "uncompleted merchandising transaction" that is too "tenuous" to qualify as a BFH.[69]

There are circumstances in which establishing a hedge to fix the differential between the bid or offer price and the purchase or sales price, respectively, may be economically appropriate. For example, a trader submitting an irrevocable bid is generally motivated to enter into this cash market bid by the differential between the trader's anticipated purchase floating price and sales fixed price. Once the irrevocable bid is submitted, the exposure is created, creating the need for the hedge. This floating differential is a function of the anticipated purchase floating price but can be fixed with a position in derivatives. To illustrate, consider a bidder to a utility's natural gas procurement auction motivated by the difference between the fixed-price bid submitted to the utility, e.g., $5.00 per MMbtu, and the expected acquisition cost that is currently $4.50 per MMbtu at the NYMEX Henry Hub price.[70] At the time of the irrevocable bid to the utility, even before acceptance, the bidder bears the outright floating-price risk associated with its acquisition cost until the contract terminates or the bid expires unaccepted. The bidder can do one of several things:

> 1) Fix the floating-price purchase risk by purchasing Henry Hub natural gas futures contracts to hedge the anticipated purchase floating-price for the quantity and duration of the bid. In this case, the bidder has locked in a fixed differential between the purchase and the bid, but it bears the risk that the bid is not accepted. In that case, the bidder bears the risk of unwinding the Henry Hub that were purchased as a hedge.
>
> 2) Bear the floating-price purchase risk during the active period of the irrevocable bid. In this case, the bidder bears no further risk if the bid is not accepted.

In the proposed Rule, the Commission would not allow the bidder to hedge its risk in scenario 1, but rather would artificially require the bidder to accept the risk in scenario 2. Yet both the hedging strategies are economically appropriate. The Commission should not exclude such types of BFH and should instead provide an additional enumerated hedge covering such cases, as discussed below.

The Commission also cites a market integrity problem created by granting this exemption. "Undue volatility could result when the winning bid is accepted and all the losing

[69] Id. at 75,720.

[70] For the sake of simplicity, we ignore transportation costs.

bidders simultaneously reduce their total positions to get below the speculative position limit level."[71] While this may be a concern in some illiquid contracts, it is generally not a concern in Henry Hub natural gas derivatives markets which are at present generally very liquid, even in the spot month. Ultimately, we believe that NGSA members and other commercial market participants are able to effectively judge and manage these liquidity costs.

With respect to hedging "a physical transaction that is subject to ongoing, good-faith negotiations, and that the hedging party reasonably expects to conclude, be treated as bona fide hedging transactions or positions," the Commission finds it difficult to distinguish "naked merchandising from speculation."[72] Moreover, the "trader has not established a definite exposure to a value change when that trader has only entered into negotiations for a fixed-price purchase or sales contract. This tentative cash position thus fails the change in value requirement."[73]

NGSA disagrees for much the same reasons as it has described above in discussing the Commission's proposed treatment of other anticipated merchandising transactions. The Commission should not exclude such types of BFH and should instead provide an additional enumerated hedge covering such cases as discussed below. Indeed, when considering the propriety of such hedges and "naked merchandising,"[74] the Commission fails to consider the fact that natural gas market participants such as producers, midstream and marketing companies, transporters, and utilities routinely engage in highly complex and often lengthy negotiations involving billions of dollars of capital investment, over extremely long investment horizons. These negotiations and resulting project development projects are often based on market prices at the time of the negotiation and development. If parties are not given the opportunity to hedge these risks, including locking in prices over a long term, the projects might never be built. There is no justifiable reason to artificially constrain legitimate risk reducing activities based on an overly narrow conception of BFH transactions.

As noted above, the Commission should expand the list of enumerated hedges to allow for hedges of anticipated exposures as provided for in the statute. Derivatives executed in anticipation of cash market positions should be recognized as BFH positions provided that the derivative reduces expected risk borne by the entity, where expected risk is the weighted average of the risk borne if the expected transaction is consummated and the risk borne if the expected transaction is not consummated, with each outcome weighted by its probability of occurrence as assessed by the entity in the exercise of its business judgment.

D. The Commission's approach to cross-commodity BFH should take into account liquidity costs and should provide for a more flexible quantitative factor test that takes into account more than just spot period correlation

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[71] Id.

[72] Id.

[73] Id.

[74] With respect to the Commission's phrase "naked merchandizing", we note two things; first, merchandizing is explicitly recognized in the statute as a proper predicate for a BFH; second, the phrase "naked merchandizing" is unknown to the statute, and the Commission should explain clearly what it means by this phrase it has invented.

The Commission cross-commodity BFH exemptions are proposed to be conditioned on a "substantial relation" between the price risk source commodity and the commodity in which the price risk is hedged. The Commission proposes a two-part, non-exclusive safe harbor for satisfying the "substantial relation" test:

1) Qualitative factor: that a "reasonable commercial relationship" between the price risk source commodity and the commodity in which the price risk is hedged (e.g., sorghum and corn, but not Dow Jones Index and crude oil)

2) Quantitative factor: that there is correlation (R) between first differences or returns in daily spot price series for the target commodity and the price series for the commodity underlying the derivative contract (or the price series for the derivative contract used to offset risk), is at least 0.80 for a time period of at least 36 months.

The Commission finds that, based on the second factor, hedges of electricity price risk in Henry Hub natural gas derivatives do not meet the quantitative factor. We are concerned the effect this restrictive safe harbor would have on liquidity in natural gas derivatives markets.

NGSA urges the Commission to be cognizant of three facts as it considers a final speculative position limits rulemaking and its provisions on the "substantial relation" test. First, the Commission should not ignore liquidity costs. While a perfect electricity hedge would be in a swap product that replicates the electricity price risk, entering into those swaps presents liquidity costs that may outweigh the weaker correlation in a more liquid instrument (e.g., Henry Hub natural gas derivatives). Second, the Commission's quantitative parameters are unduly restrictive and inadequately consider time periods and geographic location. A 36-month observation period for analyzing the quantitative relationship between the components of a cross-commodity hedge is far too long – many cross-commodity hedges correlate closely for short periods of time when some common factor has a significant influence on both markets. In the northeast, for example, winter peaking electric prices are typically driven by natural gas prices, as gas units are the peaking units in that region. In mid-summer in the pacific northwest, hydroelectric facilities may provide all the generation needed to serve electric needs. In addition, the correlation factors are too restrictive, particularly where, as discussed above, hedging instruments with closer correlations present greater liquidity costs. Third, the Commission should also note that certain correlations are stronger in deferred time periods. A cross-commodity hedge based on correlations in the spot market is only relevant for spot period hedges. A cross-commodity hedge of forward price risk should qualify based on correlations between the forward price risk and the prices in the derivatives' deferred months, not based on spot period correlations.

Another significant issue associated with the cross-commodity exemption is the "five day rule." Due to the proposed "5 day rule," in several of the enumerated hedge categories, physical delivery contracts cannot be used as a BFH during the expiry of the contract. That can be an especially significant problem for cross-commodity hedges because of the lack of any substitute hedge. If prices of the commodity being hedged are being set as a function of the closing price of the cross-commodity contract, and that contract cannot be used to hedge that commodity exposure at the time the price is set, the position is effectively unhedged. There is no reason for the entity holding that exposure to hedge it in the spot month. Clearly, this will have a negative impact on the liquidity of Henry Hub derivatives.

The commission must also be cognizant of what is and is not a cross-commodity hedge. For example, liquefied natural gas ("LNG") is, for purposes of commodity transactions, the same commodity as natural gas. Moreover, LNG imported into the United States is typically priced with reference to a Henry Hub price. Hedging LNG with Henry Hub derivatives should not be considered to be cross-commodity hedging.

Similarly, using natural gas derivatives to hedge exposures related to the pricing of "heat rate" power sales transactions is not a cross-commodity hedge. In such transactions the sale price is determined by multiplying a gas index price times a negotiated "heat rate", which reflects the implicit efficiency of the conversion of natural gas to electricity. So, for example, a particular contract might be priced at the equivalent of the NYMEX Henry Hub futures contract at a heat rate of 10. This could be done using either daily or monthly closing prices. In either case, the price of the power to be delivered would be calculated by multiplying the closing price times 10 to yield the power price per Megawatt hour (MWH). In this example, if the closing NYMEX Henry Hub price was $3.00/mmbtu, the price of power sold under the contract would be $30.00/MWH.

Logically, exposures under such contracts are frequently hedged using the NYMEX Henry Hub contract. If the power exposure is long, it can be hedged with a short HH derivative position, if the power exposure is short, it can be hedged by taking a long HH derivative exposure. NGSA submits that hedging such heat contract exposures is not a cross commodity hedge because the exposure is to changes in the price of the HH contract itself not to power prices. NGSA respectfully requests that the commission explicitly state that such hedges are not "cross-commodity".

IV. Commodity Trade Options and Other Physical Commodity Options

A. Commodity Trade Options should not be subject to speculative position limits

The 2013 NOPR seeks expressly to subject physical commodity trade options that satisfy the Commission's trade option rules ("Trade Options")[75] to speculative position limits. To do this, the proposal seeks to interpret the definition of "referenced contracts" in proposed section 150.1 to include Trade Options.[76] Under the referenced contract definition in proposed rule 150.1, Trade Options that are either (1) "directly or indirectly linked" to the price of a core futures contract or (2) "directly or indirectly linked" to the "*price of the same commodity underlying that particular core referenced futures contract* for delivery at the same location" would be subject to position limits since they meet the definition of referenced contracts.

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[75] Commodity Options and Agricultural Swaps, Notice of proposed rulemaking, 76 Fed. Reg. 6095 (Feb. 3, 2011) ("Trade Option NOPR"); Commodity Options, Final rule and interim final rule, 77 Fed. Reg. 25,320 (April 27, 2012) ("Trade Option Final Rule").

[76] See 2013 NOPR at 75,711.

Accordingly, under the 2013 NOPR, natural gas Trade Options that are priced directly off of the NYMEX Henry Hub NG contract or an index that itself is priced on or includes the NG contract, or which are priced based on natural gas delivered to Henry Hub, would be subject to position limits. On the other hand, Trade Options that are priced at a fixed price or at some other index and are delivered to one of the hundreds of other market centers throughout North America would not be subject to position limits because such contracts would not meet the definition of referenced contracts.

For the following reasons, we respectfully urge the Commission to reverse its position and confirm that Trade Options will not be subject to position limits. The Commission should also make conforming changes to Part 32 of its rules governing Trade Options to remove reference to Part 150 and the requirement that such Trade Options be subject to position limits.

1. Trade Options are not speculative financial instruments and should not be subject to speculative position limits

Unlike options on futures contracts, which settle into futures, or swaptions traded on DCMs or SEFs that settle into swaps, Trade Options, under the Commission's rules, must be intended to be physically settled so that, if struck, they result in *physical forward* contracts.[77] Furthermore, the Commission's rules also require that (1) the offeree be either an Eligible Contract Participant or a "producer, processor, or commercial user of, or a merchant handling the commodity," (2) the offeree be a "producer, processor, or commercial user of, or a merchant handling the commodity," and (3) both parties must be "entering into the commodity option transaction solely for purposes related to its business as such."[78]

Trade Options are unsuited to "***speculative***" position limits because they are ***not*** speculative positions. The statutory purpose to place limits on certain futures and swap contracts, i.e., "to diminish, eliminate, or prevent excessive speculation and market manipulation," is not satisfied by placing limits on Trade Options. To the contrary, the business purpose and offeree restrictions on Trade Options means that they cannot be entered into by speculators or mere investors, but rather must be transacted by commercial participants as part of their business as such.[79] Unlike futures contracts, Trade Options are not standardized contracts that can be bought, sold, and liquidated by all parties eligible to trade on DCMs. Unlike financial swaps, Trade Options are not financially settled contracts available to be traded by all eligible contract participants or those eligible to trade on DCMs and SEFs. Rather, Trade Options, by Commission rule, are physical-delivery contracts between a limited class of commercial persons that are involved in the business of the underlying commodity.

[77] 17 CFR § 32.3(a)(3).

[78] Id. §§ 32.3(a)(1)-(2).

[79] See Further Definition of "Swap," "Security-Based Swap," and "Security-Based Swap Agreement"; Mixed Swaps; Security-Based Swap Agreement Recordkeeping; Final Rule, 77 Fed. Reg. 48,208 at 48,229 (Aug. 13, 2012) ("Final Swap Definition") ("market participants that regularly make or take delivery of the referenced commodity in the ordinary course of their business meet the commercial participant standard of the Brent Interpretation"; "investment activity is not commercial activity").

Furthermore, in contrast to speculative positions, Trade Options must be intended to be physically delivered, and thus are used by commercial entities to: manage their physical supply or consumption needs (e.g., by contracting for one or more alternative gas suppliers to meet unknown consumption or merchandising needs); provide for a mechanism to sell production or inventory; or serve other merchandising functions. Offerors of natural gas Trade Options, for example, must have access to the underlying commodity and must be able to transport or otherwise acquire the commodity at the delivery location specified in the contract (or be prepared to take delivery, in the case of a put). Offerees of natural gas Trade Options must have takeaway capacity and some means of consuming, storing, or reselling the quantity of commodity that they elect to strike (or be prepared to make delivery, in the case of a put). Furthermore, under rules of the Federal Energy Regulatory Commission, shippers of natural gas on interstate gas pipelines must have title to the gas being transported. Like physical forward contracts, Trade Options are often subject to limitations on assignment of the contract, particularly since the parties are relying on the other party to perform the necessary delivery or receipt. In short, unlike futures and financially-settled swaps, Trade Options impose commercial and delivery risks on both offeree and offeror. The Commission should recognize the clear distinction between Trade Options and speculative positions in swaps and futures and expressly exclude Trade Options from position limits.

The Commission correctly observed in the 2013 NOPR that "forward contracts are not subject to the proposed position limits." It notes that certain forward contracts may be the basis for seeking bona-fide hedge exemptions to position limits. The same is true for Trade Options. Trade Options, in fact, if struck, settle into forward contracts. The fact that some offerors may hedge price risks, if any,[80] in certain Trade Options by using derivatives does not mean that the Commission should impose position limits on Trade Options any more than it means that it should impose position limits on physical forward contracts. The Commission should exempt Trade Options from position limits to the same extent that it excludes forward contracts from such limits.

2. The 2013 NOPR has not shown that natural gas Trade Options based on the NG contract or Henry Hub prices are "economically equivalent" to the NG core referenced futures contract or, for contracts traded OTC, perform a "significant price discovery" function

The 2013 NOPR assumes, for purposes of proposing to include Trade Options in position limits, that Trade Options that meet the definition of "referenced contracts" are "economically equivalent" under CEA section 4a(a)(5), 7 U.S.C. 6a(a)(5), to the core futures contracts such as the NYMEX NG contract.[81] Since Congress did not define the term "economically equivalent,"[82] the Commission must show that contracts linked to the core contracts, and thus

[80] To the extent that a Trade Option is indexed to the NG contract, and therefore would be a referenced contract if the Commission adopts this proposal, the price risk would not be a fixed-price risk, but rather would float with the NG price. If the offeror's supply was also indexed to NG, it would not have no price risk that needed to be hedged.

[81] See 2013 NOPR at 75,711.

[82] Id. at 75,724 n.388.

that rely on CEA section 4a(a)(5) in order to be included in position limits, are in fact "economically equivalent" under some rational basis, as any other reading would render this portion of the statute a nullity.

While we agree with the Commission that an NG look-alike swap traded on a DCM or SEF is clearly "economically equivalent" to an NG futures contract, the same is not true for NG-priced Trade Options. For example, a natural gas Trade Option delivered to Transco Zone 6 that happens to be priced based on NG, typically with some differential (e.g., a locational basis differential that approximates the cost of transportation under most conditions), is not economically equivalent to an NG futures contract, but rather is equivalent to (1) a gas option priced approximately at the Transco Zone 6 price, or, if struck, (2) a forward contract priced at the NG contract plus the differential. Like a Zone-6 priced Trade Option, an NG-priced Trade Option plus a Zone 6 locational basis is an option contact for gas delivered to, and within, Transco Zone 6, at the local market price.[83] In the case of a forward contract, since a Trade Option, when struck, results in a physical delivery contract, it is economically equivalent, when struck, to a forward contract at the same price formula. In contrast, the NG core contract is a price hedging tool, or, if taken to delivery, a means for securing gas delivery in Henry Hub, Louisiana, at the NG settlement price.

The 2013 NOPR does not explain why Trade Options that simply use an NG or a Henry Hub price are deemed to be economically equivalent to the NG core contract. Nor can it, because most, if not all, natural gas Trade Options are not economically equivalent to the NG futures contract. As noted above, a Transco Zone 6-delivered Trade Option with a NG-based price is a gas delivery contract that provides for gas delivered halfway across the country from Henry Hub. Even if the gas is transported back Henry Hub, such transportation requires paying at least variable costs (even treating reservation costs as sunk costs). In short, natural gas Trade Options requiring delivery at any location other than Henry Hub and priced at anything other than the NG settlement price are not economically equivalent to the NG contract.[84]

Accordingly, we respectfully ask the Commission to decline to subject Trade Options to position limits. Alternatively, we ask that the Commission, before subjecting any position limits

[83] Even if the basis differential is fixed, the offeror could hedge its locational basis exposure with an appropriate level of locational basis swaps. Alternatively, the offerer could accept, for whatever commercial purposes, a basis risk and not hedge the basis differential at all. A producer, for example, might prefer such a contract in order to better project its revenues in the coming months and years, since the liquidity of the NG contract might provide better price discovery than the Transco Zone 6 prices for the outer years of the contract.

[84] The same lack of economic equivalence is true for Trade Options delivered to Henry Hub but priced based on anything other than the NG price, such as a fixed price, a Henry Hub monthly bidweek survey price or daily index price. If the Trade Option delivered to Henry Hub is priced at anything other than NG, there necessarily will be a price risk for any difference between the NG final settlement price (which is 30-minute volume weighted average price on the third-to-last business day of the month) and the respective Henry Hub fixed price, monthly price, or daily price. These price differences can be significant and in fact monthly-to-daily and monthly bidweek price-to-NG financial contracts are available to hedge some of these risks. Even NG-priced Trade Options delivered to Henry Hub may have different delivery terms or other terms and conditions that distinguish them economically from NG futures that go to delivery. The Commission has not shown how any such contracts are economically equivalent to the NG core contract.

on Trade Options, make specific findings that a given Trade Option is in fact "economically equivalent" to a core contract such as the NG contract. At a minimum, we ask the Commission to clarify that natural gas Trade Options delivered to locations other than Henry Hub, or Trade Options delivered to Henry Hub but not priced specifically on the NG price, are not referenced contracts subject to position limits. However, since it is not clear that even NG-priced Trade Options are equivalent to the NG contract,[85] we ask the Commission not to impose position limits on any natural gas Trade Options at this time.

Finally, the Commission recognized that the CEA authorizes the Commission to impose position limits across multiple trading venues, but to place limits on swaps that are "not traded on or subject to the rules of a designated contract market or a swap execution facility," such as bilaterally-traded OTC Trade Options, the Commission must show that the contract "performs a significant price discovery function with respect to a registered entity" (an "SPD" function).[86] Since most natural gas Trade Options are not, as noted, economically equivalent to the NG contract, the Commission would need to make an SPD function finding before setting limits on such OTC Trade Options. The 2013 NOPR provides no discussion, however, of how OTC-traded Trade Options perform any SPD function.[87] We respectfully urge the Commission not to impose position limits on OTC Trade Options based on any SPD function determination until it explains and justifies how it meets the statutory SPD requirement.

3. The proposal to include Trade Options is unworkable and disruptive to commercial transactions

As we noted, a Trade Option priced based off of the Henry Hub NG contract or based on Henry Hub natural gas would be counted in a person's "speculative" positions (unless eligible for a hedge exemption and all paperwork necessary for such hedge is completed and maintained) because it would meet the definition of "referenced contract."[88] On the other hand, a Trade Option that is based on a fixed-price or non-NG index price and delivered to a location other than Henry Hub would not be subject to limits because those do not meet the definition of "referenced contract."

This result is incongruous and leads to increased costs, increased risks, and unnecessary burdens on market participants. For example, market participants would have an incentive to

[85] See previous footnote.

[86] 2013 NOPR at 75,760 and n.713; see also id. at 75,698 n.177 (discussing Commission authority to set limits on futures, DCM/SEF swaps, SPD function swaps, and economically equivalent swaps).

[87] A Trade Option priced at an NG price necessarily is a price-taking instrument, and hence cannot be said to perform a SPD function. In contrast, a highly liquid and openly traded NG look-alike swap traded OTC (such as the look-alike NG swap traded on the IntercontinentalExchange that previously was traded OTC but now has been converted to a futures contract) would be much more likely to perform a price discovery function with respect to the NG contract than a floating price Trade Option traded in a private negotiation. The Commission should explain in detail its interpretation of the SPD requirement if it adopts limits based on an SPD function finding in order to provide commenters with adequate notice and opportunity for comment.

[88] As noted herein, it is not clear which BFH exemption would apply in such situations, in part because these contracts are used to obtain physical natural gas. Any risk in an option would be hedged using derivatives.

structure Trade Option contracts at either fixed prices or alternative (non-NG) indexes. This would drive liquidity away from Henry Hub as a delivery location and from the NG contract as an index price in Trade Options. While an offeror could hedge a fixed-price Trade Option with an NG futures contract, the offeror would not know whether or how much gas would be struck under the option, and hence it would face increased risk and increased transaction costs to mimic an NG-priced Trade Option.

Furthermore, the nature of Trade Options makes it difficult to count positions under the Commission's guidance to count the delta-adjusted value of such positions, in futures equivalent contracts. Trade Options can involve large volumes even though they are not speculative instruments. Counting such positions on a delta-adjusted basis is not reasonable in the real world. For example, a natural gas marketer may seek to supply a series of industrial users of gas with wholesale gas, and may enter into Trade Options with several suppliers to meet its needs in case one supplier becomes unavailable. Counting all options on a delta-adjusted basis makes no sense for the option buyer since it has multiple options in this hypothetical to serve the same volume needs.

Assume further that a producer seeks to sell production from its wells and wants to give a potential natural gas purchaser an option to purchase additional tranches in the future, for example if the producer expects to be able to increase production capacity over several years. In this case, it would make no sense to require either offeree or offeror to count the delta-adjusted positions in all such options in all months combined position limits since delivery necessarily will be delivered ratably over time and is dependent on the infrastructure investment and well production. While the parties might be able to restructure the transaction to avoid it being considered a commodity option, such a result would unnecessarily burden commercial transactions, in this case a long term infrastructure and related physical commodity sale transaction, while doing nothing to serve the statutory goal of diminishing, eliminating, or preventing excessive speculation of the futures and swaps markets.

Finally, the Commission's request for specific comments underscores how unworkable its proposal is to subject Trade Options to position limits. The Commission, for example, asks whether a Trade Option offeror should be presumed to be a "pass-through swap counterparty" eligible for the pass-through BFH exemption, and observes that, if "trade options were excluded from the definition of reference contracts, then commodity derivative contracts that offset the risk of trade options would not automatically be netted with such trade options for purposes of non-spot month position limits."[89] These questions erroneously assume, among other errors, that (i) Trade Options are analogous to swaps, rather than forward contracts (despite the fact that Trade Options will become forward contracts if the offeree exercises its right), and (ii) positions in Trade Options can be netted with positions in referenced contracts, such as NG futures and NG look-alike swaps. As noted above, natural gas Trade Options are not economically equivalent to NG futures and NG look-alike swaps. Also, one would not "net" Trade Options with referenced contracts any more than one would "net" forward contracts with referenced

[89] 78 Fed. Reg. at 75,711.

contracts.[90] Like with a forward contract, if a Trade Option creates a price risk that needs to be hedged (e.g., a fixed-price Trade Option), one may use a derivative to hedge that risk. Nor is it clear whether any BFH exemption would apply to the Trade Option itself, because these options are used to buy or sell physical natural gas, and any risks in such options might be hedged with derivatives.

4. Applying position limits to Trade Options would impose significant administrative costs on offerees and offerors and would provide no commensurate benefit

Including Trade Options in position limits would subject hundreds of commercial parties to costly tracking and potentially bona-fide hedge documentation and reporting requirements without any incremental regulatory benefit. Given the uncertainties of the Commission's intended scope of this rule, the costs to commercial parties of subjecting Trade Options to position limits is hard to quantify. But because Trade Options do not pose any risk of undue or excessive speculation, any costs incurred will greatly exceed any benefits to the Commission and the public.

Putting aside the very significant issue of which contracts are forwards and which contracts are Trade Options, since Trade Options have never been subject to position limits, commercial parties do not have any systems in place to: distinguish between Trade Options that are referenced contracts and those that are not; monitor the number and quantity of referenced-contract Trade Option positions across delivery points and trading venues; and integrate them with other position tracking systems; generate position reports. Building the required infrastructure and reporting systems will be expensive, time consuming, and recurring.

5. A notice filing to exempt Trade Options from position limits is unnecessary and should not be imposed

The 2013 NOPR asked whether the Commission should instead of excluding Trade Options from position limits, "provide an exemption under CEA section 4a(a)(7) that permits the offeree or offeror to submit a notice filing to exclude their trade options from position limits? If so, why and under what circumstances?"[91] This alternative is not necessary because, as explained above, Trade Options are not properly included in speculative position limits. There is little purpose in imposing additional filing requirements on commercial market participants, especially in the case of Trade Options. Such a requirement forces parties to incur the cost of completing and submitting the required paperwork, and potentially justify why their Trade Options should be excluded. Little is gained by this process. Parties to Trade Option are already required to file annual Form TOs. The 2013 NOPR does not articulate any purpose that this additional filing would serve.

[90] It is unclear how one could even net a physical delivery option priced at NG but delivered in the northeast with an NG futures or look alike.

[91] 2013 NOPR at 75,711.

B. The Commission should likewise not impose position limits on other physical energy commodity options that might not meet the Trade Option definition

The Commission does not explicitly discuss imposing position limits on commodity options that do not meet the Trade Option definition. But since, at least at present, the Commission considers such options to be swaps under the CEA, it appears that other commodity options would be subject to limits if they meet the "referenced contract" definition. For the following reasons, we respectfully urge the Commission to clarify that energy commodity options are not to be counted in position limits. The Commission should also make conforming changes to Part 150 to make this clarification.

First, the Trade Option rule is an interim final rule, and it is unclear whether, as applied to energy commodities, commodity options that do not otherwise meet the Trade Option definition should be treated as swaps. As noted above, in order to take or deliver natural gas, an entity must have transportation rights, storage rights, and source or consumption needs (including for utilities and competitive suppliers, load requirements). In addition, sellers of wholesale natural gas have blanket certificates under Federal Energy Regulatory Commission requirements to make such sales. Therefore, natural gas, by nature, is bought and sold by market participants in their business as such, and it is not clear how physical commodity options that for some reason do not meet the Trade Option definition (or are not being treated by the parties as Trade Options in an abundance of caution) should not be afforded similar treatment as Trade Options. In the face of unclear application of the Trade Option rule, the Commission should not impose position limits on physical energy commodities such as natural gas.

Second, the final swap definition as applied to contracts with volumetric optionality explicitly sought additional comments addressing the Commission's interpretation.[92] We and many other commenters have filed comments seeking clarity and reconsideration of the final swap definition's volumetric optionality rules, but there has been no action on those comments. Since it is unclear how the Commission intends to apply the seven-part test for volumetric optionality in all cases involving natural gas contracts and other physical energy commodities, it should not therefore subject any physical energy commodity options to position limits at this time.

Third, the Commission should not subject any other physical energy commodity options to position limits for many of the same reasons noted above with respect to Trade Options, including the fact that (1) position limits are meant to deter excessive speculation, and no finding of speculation has been made to any physical energy commodity options; (2) physical energy commodity options are typically traded OTC, and the Commission has no authority to set position limits on OTC contracts that are not economically equivalent to core futures contracts unless it makes a specific finding that the contract serves a significant price discovery function with respect to exchange and SEF-traded contracts; and the Commission has not made any economic equivalent or SPD function findings; (3) applying position limits to physical energy commodity options is unworkable and it is unreasonable to require the counting of all physical

[92] Final Swap Definition, 77 Fed. Reg. at 48,241.

energy commodity options; and (4) imposing limits on physical energy commodity options is costly while not reducing excessive speculation.

C. As an alternative, the Commission should exempt Trade Options and other physical energy commodity options from speculative position limits or at least withdraw its proposal until it justifies imposing speculative position limits

As an alternative, NGSA requests that the Commission use its exemptive authority under CEA Section 4a(a)(7) to exempt Trade Options and other physical energy commodity options from federal position limits. As a basis for our request, we refer to and incorporate the points raised above in section IV.A. and IV.B.

Even if it does not exempt Trade Options and other physical energy commodity options from Position limits, the Commission should withdraw its proposal in its entirety until, and unless, it can issue a proposal justifying why it believes that Trade Options and other physical energy commodity options should be subject to speculative position limits. This rulemaking marks the *first time* that market participants have been afforded an opportunity to provide comments prior to a final (or an "interim final") order purporting to subject Trade Options to Commission position limits. The Commission's Trade Option Final Rule, published in the Federal Register on Friday, April 27, 2012, was the first Commission issuance providing market participants any notice that trade options would be subject to, among other requirements, position limits under then-final Part 151 rules. Unfortunately, such "notice" was in the form of a final, albeit "interim final" rule that did not give any advance notice of such a requirement prior to it becoming "final." In fact, the Trade Option Proposed rulemaking was completely silent on the final rule's proposal to subject Trade Options to position limits.[93]

Furthermore, neither the proposed nor final Part 151 Position Limits rulemakings, which were vacated and which lead to this 2013 NOPR, discussed including Trade Options in the position limits. This was not surprising since the Trade Option rule was issued *five months after* the final Part 151 position limit rules were finalized on November 18, 2011.[94] And because the

[93] The Trade Option NOPR, published on February 3, 2011, did not provide any notice that Trade Options were intended to be subject to position limits. In fact, most of the Trade Option NOPR's proposed section 32 was blank (i.e., nearly all sections were "reserved") and thus much of the content of the final Part 32 rule was adopted for the first time in the Trade Option Final Rule. See Trade Option NOPR, 76 Fed. Reg. at 6108-09. In fact, the word "limits" was used only twice in the entire NOPR: (1) at page 6097 in the context of citing the Commission's general Dodd-Frank authority; and (2) at page 6099 when quoting an agricultural product commentator again referring merely to the Commission's general Dodd-Frank authority. Many commenters, including NGSA, therefore provided comments in response to the "final" rules – a process that does not adequately meet the Commission's notice and comment requirement of the Administrative Procedure Act. Yet even then, the Commission has not responded to any of the comments, and thus commenters are still left uncertain about how the Commission intends to justify position limits on Trade Options.

[94] Position Limits for Futures and Swaps, Final rule and interim final rule, 76 Fed. Reg. 71,626 (Nov. 18, 2011). The proposed rule, published on January 26, 2011, and final rule defined "swaption" in Part 151 to be an option to enter into a swap or a physical commodity option, but an option to enter into an option is not the same as an executed and enforceable commodity option, let alone the same as a Option, which is an even more narrow category of executed commodity option. The term "trade option" or similar term is not mentioned anywhere in any the Part 151 proposal or final rule.

Part 151 rules were concluded well before the Trade Option Final Rule (which provided the first notice that Trade Options would be subject to position limits), interested parties had no reason to provide comments on Trade Options in the part 151 position limits rulemakings.

The 2013 NOPR provides little guidance on key issues related to why the Commission thinks it is appropriate to subject Trade Options and other physical energy commodity options to position limits and how such limits are appropriate under the current legal and regulatory framework governing "speculative" position limits. The discussion on page 75,711 of the 2013 NOPR appropriately asks "whether it would be appropriate to exclude trade options from the definition of referenced contracts and, thus, to exempt trade options from the proposed position limits." However, the 2013 NOPR does not provide any reasoned discussion of, among other things, (i) why Trade Options and other physical energy commodity options should be subject to position limits, (ii) on what authority the Commission purports to impose such limits, (iii) why or how positions in Trade Options and other physical energy commodity options could be considered as part of "speculative" positions that the limits are meant to restrict, (iv) which Trade Options could be considered as "economically equivalent" to core futures contracts and how that conclusion was reached, and (iv) under what authority the Commission believes that Trade Options and other physical energy commodity options traded off of DCMs or SEFs are permitted, by law, to be subject to position limits (i.e., without a finding that a an OTC-traded option is an SPD function swap).

Finally, and significantly, as mentioned in section IV.B., there remains considerable uncertainty about whether natural gas and other physical energy commodity options are to be classified as option contracts or as forward contracts under the Commission's final swap definition and its three-part test for options and seven-part test for volumetric options. With respect to volumetric optionality, the Commission explicitly sought additional comments, recognizing that the Trade Option rule was an interim final rule, and also because the Commission proposed the multi-factor tests for the first time in the final rule.[95] In response, over 40 sets of comments have been submitted on the topic, the Commission has yet to issue any clarification. In light to this uncertainty, it would be arbitrary and capricious to force parties to forego prudent risk management activities or to incur costs of either (i) complying with BFH exemption documentation or (ii) developing the infrastructure and processes to include Trade Option and other physical commodity option contracts in their position limits calculations and monitoring, only to have the Commission later issue a clarification along the lines as those requested in the comments.

In the absence of clear Commission rationale for including Trade Options and other physical energy commodity options in position limits, and in the absence of clarity in the final swap definition as to which contracts qualify as commodity options versus forward contracts, commenters are left to guess on these critical issues – quite possibly requiring commenters to shoot at a moving target. Yet providing answers to such questions is important to provide adequate notice and opportunity for comment. Accordingly, in light of the significant and serious consequences of including Trade Options and other physical energy commodity options in position limits (which these comments address in part, given the limited Commission guidance

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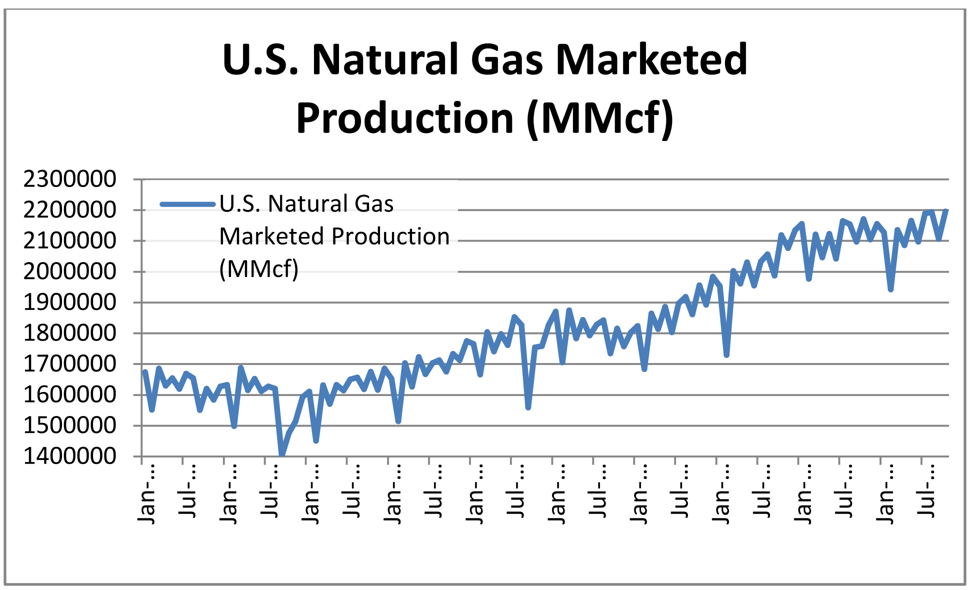
[95] See Final Swap Definition, 77 Fed. Reg. at 48,237-42

thus far), we respectfully urge the Commission to withdraw its proposal to subject Trade Options and other physical energy commodity options to position limits in entirety. After considering these and other comments regarding Trade Options, if the Commission still thinks it is appropriate and consistent with the statute to consider subjecting Trade Options and other physical energy commodity options to position limits, the Commission could issue a separate rulemaking proposal that provides meaningful notice and opportunity for comment on the Commission's proposed justification and mechanism for doing so.

V. Additional Comments

A. The Commission should adopt the alternative spot-month position limit levels based on revised estimates of deliverable supply at Henry Hub

NGSA supports the alternative proposed initial spot-month limit levels proposed by the Intercontinental Exchange, Inc. and CME Group estimates of deliverable supply. CME's estimates, for example, correspond to an alternative spot-month limit levels of 3,900 contracts, significantly above the 1,000 contract level currently used in Henry Hub natural gas contracts. Underlying this spot-month limit level is an estimated deliverable supply of 154,200,000 MMBtu. This estimated deliverable supply estimate is consistent with NGSA members' observations. The chart below describes how marketed natural gas production in the U.S. has increased over 35% in the last ten years.[96] Similarly, the nation's natural gas pipeline capacity has expanded over the same period.[97] Both of these changes in the market suggest a significant increase in deliverable supply at Henry Hub since the current levels were established in 2004.



[96] Data taken from U.S. Energy Information Administration ("EIA"), Natural Gas Gross Withdrawals and Production, http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_m.htm (last visited Jan. 12, 2014).

[97] EIA, U.S. Natural Gas Interstate Deliveries (last visited Jan. 12, 2014). See also ICF International, Natural Gas Pipeline and Storage Infrastructure Projections Through 2030 (Oct. 20, 2009), at 55, available at http://www.ingaa.org/File.aspx?id=10509 (last visited Jan. 12, 2014).

As the Commission considers whether to adopt updated estimates of deliverable supply for Henry Hub natural gas, we urge the Commission to include "supply that is committed to long-term agreements."[98] In the natural gas markets, this long-term agreement supply is "consistently and regularly made available to the spot market for shorts to acquire at prevailing economic values" and should therefore be included in the estimates of deliverable supply the Commission adopts. While a significant portion of natural gas deliverable supply is committed to long-term agreements, almost all of this natural gas is marketed and re-marketed by wholesale resellers (e.g., marketers, merchants, producer marketer-affiliates, end-user marketer affiliates, etc.). The reason why (i) a significant portion of natural gas is committed to long-term agreements but is also (ii) a part of deliverable supply is that the counterparties to the long-term supply agreements are wholesale resellers who resell these long-term supplies at "prevailing economic values."

B. The Commission's position limits on cash-settled contracts should be eliminated or be increased substantially and based on open interest

Under the Act, the position limits established by the Commission must be limited to what is "necessary" and "appropriate" to address "[e]xcessive speculation . . . causing sudden or unreasonable fluctuations or unwarranted changes in prices" and to "prevent market manipulation, squeezes, or corners."[99] To be consistent with the Act's requirements and the Commission's own well-established policies, the new position limits should focus on (1) facilitating convergence between physical and financial markets and (2) preventing market manipulation, *e.g.,* corners and squeezes, between physical and financial markets. This would be best accomplished by limiting the position limits in the final rule to physical delivery contracts in the spot month only. Such contracts have far greater potential for the kind of market manipulation and distortion the rule was intended to address than do any cash-settled contracts on contracts outside of the spot month.

Based on the requirements of the Act and the Commission's well-established policies, position limits on cash-settled contracts in the spot month should be eliminated from the final rule, or should be increased substantially and be based on open interest in the referenced contracts, as opposed to deliverable supply in the commodity. The Commission appropriately recognizes the importance of higher limits for cash-settled contracts in proposing the "conditional limit." To the extent there is a limit on cash-settled contracts, the conditional limit provides that a trader in a financially settled contract be permitted, based on a conditional position limit, to take a speculative position five times the spot month position limit for the physical contract, if the trader neither holds nor controls positions in the spot-month physical delivery referenced contract.

While higher limits for cash-settled contracts will help facilitate liquidity, the higher limits for cash-settled contracts should not be limited to traders that only hold cash-settled positions. The condition that the trader hold no spot-month position in the physical contract has

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[98] Appendix C of 17 CFR part 38.

[99] *See* CEA §§ 4a(a)(1), 4a(a)(3)(B).

the potential to harm the market for that physical contract by moving liquidity from the spot month period in the relevant physical delivery contract to the cash-settled contract. Additionally, a bona fide hedger that is a party to one or more trade options would not meet the conditional exemption.

Removing or reducing the conditional limit for cash-settled natural gas contracts may disrupt present market practice and harm liquidity in the cash market increasing the cost of hedging and possibly preventing convergence between physical and financial markets. The conditional limit avoids unnecessarily limiting liquidity and price discovery in contracts with less potential to impact the physical contract settlement and has the beneficial effect of incenting end users with large positions to move their positions to cash-settled contracts.

The requirement that the trader hold no spot-month position in the physical contract has the potential to harm the market for that physical contract. The 2013 NOPR's "second alternative" to the proposed conditional limit would address this concern and is a more appropriate approach to conditional limits for cash-settled contracts. Under the second alternative, the expanded limits on cash-settled contracts would be permitted regardless of positions in the underlying physical-delivery contract. This alternative better protects the market for the physical delivery contract, and there is no evidence in the "Necessity Finding" in the proposed rule that suggests that this alternative would fail to provide adequate protection against excessive speculation. Therefore, NGSA urges adoption of the second alternative in place of the proposed conditional limit.

C. The Commission should not adopt a new aggregation standard that requires aggregation of positions based on ownership in an entity alone

With respect to the separate, "Aggregation of Positions," proposal ("2013 Aggregation NOPR"),[100] NGSA recommends that the Commission forego its proposed owned entity aggregation requirement because it (1) imposes serious undue costs on NGSA members, (2) exceeds the Commission's authority to require the aggregation of the accounts of another person, and (3) is an unwarranted departure from previous Commission and DCM aggregation requirements. The status quo position aggregation rules are an alternative that are less costly and achieve at least the same policy benefit for the Commission. Under the status quo, the Commission may bring enforcement action against an investor if it directs or otherwise controls the trading of an owned entity whose positions it claims it does not control and therefore does not aggregate.

1. Background on the Commission's proposed owned entity aggregation requirement

Under proposed 150.4(a)(1) Commission proposes a general ownership-based aggregation requirement. Under this proposed provision, if a person owns 10 percent or more of an ownership interest in "accounts" then it is required to aggregate those accounts. The Commission proposes to interpret "accounts" to include the accounts of an owned entity if a

[100] 78 Fed. Reg. 68,946 (Nov. 15, 2013).

person has an ownership interest of 10 percent or more that entity. This proposed general rule is subject to two exemptions:

1) Under proposed 150.4(b)(2), the Commission proposes an aggregation exemption for ownership interests up to 50 percent provided certain conditions indicative of a lack of trading control are met.[101]

2) Under proposed 150.4(b)(3), the Commission proposes an aggregation exemption for ownership interests above 50 percent provided that the same trading control-based conditions for the proposed 150.4(b)(2) exemption are met plus two additional conditions: (1) certification that the Related Entities' financial results are not consolidated in a financial statement pursuant to relevant accounting rules; (2) each director for the owned entity certifies that (a) all of the owned entity's positions are bona fide hedging positions, or (b) the owned entity's positions do not exceed 20% of any position limit. [102]

2. The Commission's proposed approach to owned entity aggregation imposes serious undue costs on NGSA members

The Commission's proposed owned entity aggregation rules vastly increase the costs NGSA members would bear, as discussed in part in section III.A.4 above, to comply with spot month speculative position limits. NGSA members would bear enormous costs to build out position surveillance systems out to businesses in which they have 50 percent or more equity investment whose commodities trading they currently do not control or even monitor, as would be required under the Commission's proposal.

We note that the conditions associated with the proposed 150.4(b)(3) relief are so restrictive as not to be useable. NGSA members make large equity investments in companies in order to generate returns that show up on financial statements. Therefore the requirement that financial statements not be consolidated frustrates the very purpose of equity investment. Moreover, requiring the investor to have the owned entity agree to restrict its commodities trading to just 20 percent of a position limit is a serious constraint on their risk management program, particularly in light of the Commission's proposal to limit the scope of the BFH exemption to just enumerated BFH positions, as discussed above in III.A above.

We disagree with the Commission's view that "that an aggregation requirement [based on ownership in an owned entity alone] would [not] lead to more information sharing..."[103] NGSA

[101] These include: (1) enforced written procedures to prevent sharing of trading information; (2) physical separations; (3) separately developed and independent trading systems; (4) no sharing of employees that control trading decisions; and (5) no sharing of risk management systems that permit sharing of trading information or strategies. This exemption is effective upon submission of a notice filing under proposed 150.4(c)(1).

[102] We understand that the limitation that an owned entity's positions be limited entirely to bona fide hedging positions is simply a sub-set of the alternative requirement that would restrict speculative positions up to 20 percent of any limit. CEA section 4a(c)(1) prohibits the Commission from restricting the bona fide hedging positions of any trader. "No rule, regulation, or order issued under subsection (a) of this section shall apply to transactions or positions which are shown to be bona fide hedging transactions[.]" CEA section 4a(c)(1).

[103] 78 Fed. Reg. at 68,957.

members would have to vastly increase information sharing across businesses in which they have an investment if the owned entity aggregation requirements are finalized as proposed.

NGSA notes that while common ownership can create incentives to coordinate trading, effective firewalls that, are enforceable under federal law, designed to prevent coordinated trading can counter these incentives. Accordingly, the Commission should encourage the independent control of positions. The Commission should attribute positions to the *controller* of multiple *controlled* accounts that amount to an unduly large position. Former Chairman Gary Gensler described the purpose of the position limits regime (including position aggregation rules) in 2011 as follows:

> When the CFTC set position limits in the past, *the agency sought to ensure that the markets were made up of a broad group of market participants with a diversity of views*. At the core of our obligations is promoting market integrity, which the agency has historically interpreted to include ensuring markets do not become too concentrated.[104]

Requiring NGSA members to subject an investor and the firm in which they have a large investment under common trading control would discourage, not encourage, the "diversity of views" that former Chairman Gensler sought to promote in promulgating position limits rules, including the 2013 Aggregation NOPR.

3. The Commission's proposed approach to owned entity aggregation exceeds its authority under the CEA

The Commission interprets CEA section 4a as providing it authority to "require[] aggregation on the basis of either ownership or control of an entity."[105] We believe this conclusion is in error. The relevant portion of CEA section 4a(a)(1) provides (emphasis added):

> [T]he positions held and trading done by *any persons directly or indirectly controlled by such person* shall be included with the positions held and trading done by such person[.]

In other words, the first part of this provision states that the positions held and trading done by *another person*, "any persons," (e.g., the firm in which an investor invests) that is *directly or indirectly controlled by a person*, "such person," (e.g., the investor) shall be included with the positions held and trading done by that person, "such person," (e.g., the investor). The second part of this provision requires a person to aggregate the positions they own directly, i.e., "positions held" or that they control, "trading done."

By its terms then, CEA section 4a(a)(1) only allows the Commission to require the aggregation of positions on ownership alone when those positions are directly owned by a person. The positions of another person are only to be aggregated when the person has direct or indirect control over the trading of another person.

[104] Statement on Support of the Dodd-Frank Rulemaking of Chairman Gary Gensler, http://www.cftc.gov/PressRoom/SpeechesTestimony/genslerstatement011311b (Feb. 17, 2011) (emphasis added).

[105] 78 Fed. Reg. at 68,956.

4. **The Commission's proposed approach to owned entity aggregation is an unwarranted departure from previous Commission and DCM aggregation requirements**

Neither the Commission, nor DCMs operating under its oversight, have ever had rules explicitly requiring the aggregation of positions of another legal person solely on the basis of ownership. The Commission or DCMs have also never promulgated rules (that were not vacated) or issued an interpretation that the term "accounts" in part 150 extended to the accounts of other persons who are commonly owned absent some indicia of actual trading control.

A Commission policy statement from 1979 ("1979 Statement") is the origin of the current Commission aggregation rules.[106] The first point of the 1979 Statement provides. "[e]xcept for a limited partner or shareholder in a commodity pool, any person who has a 10 percent or more financial interest *in an account* will be considered as an *account controller*" (emphasis added).[107] In other words, an ownership interest in an account was indicia of control. Furthermore, the concept of an "account" in the 1979 Statement did not explicitly or implicitly extend to the accounts of another person. In contrast to the Commission's new interpretation of "account," the 1979 Statement defined "discretionary account" as "a commodity futures trading account for which buying and/or selling orders can be placed or originated, or for which transactions can be effected…"[108] Here, as elsewhere in the Commission's use of the term "accounts" refers to the trading accounts directly or personally held or controlled by a person.

The 2013 Aggregation NOPR cites a rulemaking from 1999 to support its interpretation of CEA section 4a(a)(1)'s ownership prong (the "positions held" language quoted above) encompasses owned entities' positions.[109] The 1999 Rulemaking does not make any such statement. The 1999 Rulemaking only covered the accounts held personally by a person (e.g., an investor or parent corporation), not accounts of other persons in which the person invested (e.g., their investment or a subsidiary). For example, the 1999 Rulemaking clarified that when a person "holds or has a financial interest in or controls more than one account, all such accounts shall be considered by the futures commission merchant, clearing member or foreign broker as a single account…"[110]

This statement from the 1999 Rulemaking raises the question: when does a person "hold[] or [have] a financial interest" in accounts that require aggregation. The Commission's 1999 Rulemaking the Commission noted that the "requirements relating to aggregation of

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[106] Statement of Policy on Aggregation of Accounts and Adoption of Related Reporting Rules, 44 Fed. Reg. 33,839 (Jun. 13, 1979).

[107] Id. at 33,845.

[108] Id.

[109] "[T]he Commission . . . interprets the 'held or controlled' criteria [of CEA section 4a] as applying separately to ownership of positions or to control of trading decisions." 2013 Aggregation NOPR at 68,956 citing Revision of Federal Speculative Position Limits and Associated Rules, 64 Fed. Reg. 24,038, 24,044 (May 5, 1999) ("1999 Rulemaking").

[110] Id. at 24,046.

positions, including the exceptions provided in the 1979 Policy Statement currently are included implicitly in the Commission's large-trader reporting rules."[111]

The Commission's large trader rules require the aggregation of the multiple accounts of a "person," not of a person and their owned entities. For example, 17 CFR 17.00(b) requires that futures commission merchants ("FCMs") aggregate the positions of any "person" if that "person holds or has a financial interest in or controls more than one account," for the purpose of determining whether that "person" holds a position in excess of a reporting level (emphasis added). The rules relating to the Commission Form 40, 17 CFR 18.04(b), distinguish between owners of the "reporting trader" and owners in the "accounts of the reporting trader" as well.

The Commission also cites its definition of "proprietary account" which does explicitly encompass accounts of affiliates.[112] However, the fact that the term "proprietary" explicitly includes the accounts of "business affiliates" does not support the Commission's contention that owned entity accounts are implied in past Commission rules covering accounts in which a person has a financial interest.

We note that DCMs currently aggregate positions of owned entities when ownership is combined with actual trading control.[113] In the 2010 *Matter of Vitol Inc. et al.*, the Commission settled a claim against a company who had affiliates (i.e., under common ownership) that were under common trading control but failed to disclose certain information indicative of this common trading control.[114] As a result of this, NYMEX failed to understand the common trading control between the affiliates and accordingly failed to aggregate the affiliates' positions. The Commission brought an enforcement action against the affiliates for failing to disclose information relating to the "flow of trading information between" the affiliated entities and the "limited nature of the barriers to trading information flow between." These facts would have only been relevant, however, if common trading control was necessary for aggregating the positions of the affiliates. It is important to note that common ownership-related facts were presented in the order.

The Commission's erroneous interpretation of its past rules on account aggregation undermines the economic calculus underpinning its rules. In its discussion of "Cost-Benefit Considerations," the 2013 Aggregation NOPR states that its proposed owned entity aggregation policy is "more permissive than the 10 percent [owned entity position aggregation] threshold currently provided."[115] The Commission therefore assumes a cost-benefit baseline that requires

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[111] Id. at 24,043 citing, e.g., 44 Fed. Reg. at 83,839. Indeed, 17 CFR 17.00(b)(3) confirms that the aggregation of multiple accounts in the position limits context works in same way as large trader reporting: "[m]ultiple accounts owned by a trader shall be considered a single account as provided under §§150.4(b), (c) and (d) of this chapter."

[112] 2013 Aggregation NOPR at 68,956 citing 17 CFR 1.3(y).

[113] CME Rule 559.D.2, available at http://www.cmegroup.com/rulebook/CME/I/5/5.pdf).

[114] See In the Matter of Vitol Inc. et al., Docket No. 10-17 (CFTC Sept. 14, 2010), available at http://www.cftc.gov/ucm/groups/public/@lrenforcementactions/documents/legalpleading/enfvitolorder09142010.pdf. The Commission found that Vitol and VCM willfully failed to correct NYMEX's misperception of the "true nature of the relationship between" Vitol and its VCM and imposed a civil monetary penalty of $6 million. Id.

[115] 78 Fed. Reg. at 68,968.

aggregation of positions for position limit compliance purposes based solely on ownership, regardless of the existence of common control. As discussed above, the baseline the Commission has assumed is inaccurate.

D. The Commission should clarify that cash-settled contracts are subject to spot-month position limit levels based on spot month price exposures

Proposed 150.1's definition of "spot month" for cash-settled contracts at paragraph (2) is defined as "the period of time beginning at the earlier of the close of trading on the trading day preceding the period in which the underlying cash settlement price is calculated, or the close of trading on the trading day preceding the third-to-last trading day…" This would mean that a calendar month average price Henry Hub natural gas contract based on prompt month settlement prices could have a spot month that begins weeks in advance of a physical-delivery contract.

A provision at the end of this proposed definition states, however, that "if the cash-settlement price is determined based on prices of a core referenced futures contract during the spot month period for that core referenced futures contract, then the spot month for that cash-settled contract is the same as the spot month for that core referenced futures contract." It appears this provision would not apply to calendar month average price contracts because their cash-settlement price is based only in part on "prices of a core referenced futures contract during the spot month period."

We do not believe this was the Commission's intention and we recommend therefore that the Commission clarify that cash-settled contracts are subject to spot-month position limit levels based on exposures to prices in the spot month. For example, if there are 20 settlements during a contract month and a contract is cash-settled based on the average of these settlements times a notional quantity of 100,000 MMBtu and the spot-month is three days long, then 3/20 of 100,000 or 15,000 MMBtu should be subject to spot month position limits.

E. The Commission's definition of "referenced contract" as a proxy for "economic equivalent" is over broad as applied to OTC swaps

The above discussion on Trade Options – namely section IV.A.2. that the Commission must show either "economic equivalence" or make an SPD function finding to subject OTC swaps to position limits – also applies to other categories of OTC swaps. For example, a float-for-float swap that has one floating price based on the Henry Hub NG monthly contract, and the other floating leg priced on the Platts' *Gas Daily* average is not "economically equivalent" to an NG contract. Simply because such swap uses NG as a reference price for one leg of the float-float swap does not make the swap economically equivalent to the Henry Hub NG contract, which is an outright price instrument (i.e., a fixed-for-float product based on the relevant NG contract month or months). Indeed, the NG contract and the monthly-daily float-for-float index swap are much different economically. Thus, the Commission's definition of "referenced contract" to include swaps that refer to the core futures contract is overly broad and unworkable as applied to OTC swaps. The Commission should therefore revise its rules and guidance to state what OTC swaps are in fact "economically equivalent" to a core futures contract such as the NG contract and explain in detail why. As for DCM and SEF swaps, those platforms could indicate which contracts are in fact "economically equivalent" to referenced contracts, for federal position limit purposes, in the product description for that instrument, so that market participants know in advance which products to include in calculating positions.

VI. Conclusion

As discussed above, NGSA believes that speculative position limits should encourage, not unduly curb commercial risk management practices. The Commission's proposals, if finalized as proposed, would have a negative impact on NGSA members' ability to manage their commercial risks. In order to address these concerns, NGSA recommends, most importantly:

1) Preserving the bona fide hedging exemption for positions that qualify under CEA section 4a(c)(2) definition of a "bona fide hedging transaction or position" but that are not specifically enumerated by the Commission, i.e., "non-enumerated" bona fide hedge positions described under current 17 CFR 1.3(z)(3). See section III.A.
2) Clarifying the Commission's interpretation of the "economically appropriate" criterion for the bona fide hedging position definition to accommodate a wide array of prudent commercial risk management practices. See section III.B.
3) Reconsidering, striking, or revising certain incorrect Commission conclusions that certain risk reducing hedging activities used by natural gas commercial participants, particularly anticipated hedging activities, are not bona fide hedges. See section III.C.
4) Clarifying and correcting its analyses of bona fide hedges used in the natural gas and related industries, including that (i) using natural gas derivatives to hedge LNG exposure is not a cross-commodity hedge and (ii) when the price to be charged for a physical commodity (for example, electricity) is based on a natural gas price, using natural gas derivatives to hedge that exposure qualifies as a "same commodity" hedge, because the derivatives reference the commodity that is referenced in pricing the cash market transaction, rather than a cross commodity hedge. See section III.D.
5) Not subject Trade Options and physical energy commodity options to speculative position limits because such products are not speculative instruments. See section IV.
6) Adopting the alternative spot-month position limit levels for Henry Hub Natural Gas referenced contracts based on CME Group's estimate of deliverable supply. See section V.A.
7) Permitting substantially higher limits for cash-settled contracts and remove the prohibition on the trader carrying a position in the physical delivery contract. See section V.B.
8) Not adopting an aggregation standard that requires aggregation based on ownership of an entity alone. See section V.C.

Sincerely,

Natural Gas Supply Association