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Anthony Luna
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3D SEISMIC ANALYSIS AND CHARACTERIZATION OF A STACKED TURBIDITE CHANNEL: NIGER DELTA COMPLEX

being

A Thesis Presented to the Graduate Faculty of the Fort Hays State University in Partial Fulfillment of the Requirements for the Degree of Master of Science

by

Anthony Luna
B.S., University of California Santa Barbara

Date______________________  Approved____________________________

Major Professor

Approved____________________________

Chair, Graduate Committee
GRADUATE COMMITTEE APPROVAL

The Graduate Committee of Anthony Luna hereby approves his thesis as meeting partial fulfillment of the requirement for the Degree of Master of Science.

Approved________________________________
Chair, Graduate Committee

Approved________________________________
Committee Member

Approved________________________________
Committee Member

Approved________________________________
Committee Member

Date____________________
ABSTRACT

A stacked turbidite channel was interpreted from 3D seismic data acquired in the Niger Delta off the west coast of Africa. In offshore environments, such as the Niger Delta, submarine canyons provide a conduit for currents to transport large sediment loads to form stacked turbidites. Turbidite channels are typically convoluted deposits and contain sands that are potential reservoir targets of hydrocarbon exploration. The internal characteristics of these turbidites are often complex and difficult to interpret accurately. This study characterizes the morphology of a stacked turbidite deposit by describing key features that are commonly found in turbidite channels, including: channel sinuosity, facies, repeated cutting and filling, and stacking patterns. These ubiquitous components of deepwater deposits are important for efficient reservoir characterization and can be resolved in most seismic data sets. The presence of shale diapirs in the Niger Delta Complex complicates the interpretation of channel morphology and potential reservoir areas. By interpreting the channel’s key features it was determined that the channel is highly sinuous and has been cut off in several sections forming oxbows. Channel fill is highly variable, but most likely consists of four main facies: basal lags, slumps, high net to gross stacked channels, and low net to gross channel levees. Subchannels present in the data are commonly stacked in vertical and lateral patterns. Also, through attribute analysis three potential reservoirs were identified and recommended as drilling targets.
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INTRODUCTION

Extensive investigation for hydrocarbons has been conducted on land, leaving offshore drilling as one of the last remaining frontiers for petroleum exploration. Turbidite channels are one of the major drilling targets of offshore exploration programs. Through the use of 3D seismic data, especially from West Africa, Gulf Coast, and North Sea, the industry has significantly increased its knowledge about these complex deep water reservoirs (Mayall et al., 2006).

Purpose

Understanding these complex deposits is important for hydrocarbon exploration via reservoir characterization and development. The purpose of this study is to characterize a turbidite channel and apply it to reservoir identification. Similar to the approach described by Mayall et al., (2006), I characterized a turbidite channel interpreted from 3D seismic data by:

- Mapping important horizons such as, the main channel’s base and top
- Describing and analyzing “key elements” found in turbidite channels such as, sinuosity, facies, cut and fill episodes, and stacking patterns
- Analyzing shale diapirs effects
- Extracting attributes to locate possible reservoirs

Study Area

The study area is located within the Gulf of Guinea off the west coast of the Niger Delta in Africa (Figure 1). The Niger Delta Complex covers an area of approximately 100,000 square miles; the offshore portion covers approximately 70,000 square miles (Chukwu, 1991; Magbagbeola and Willis, 2007).
Sediments deposited within the study area consist of marine and fluvial sediments that range in age from Cretaceous to Holocene (Kostenko et al., 2008). Short and Stäublee (1965) described type sections for three main Niger Delta formations. These formations, from oldest to youngest, are the Akata Shale, Agbada Formation, and the Benin Formation. Roll-over anticlines, toe-thrust faults, shale diapirs, and deepwater channel systems are major features present in the Niger Delta (Chukwu, 1991; Cross et al., 2009).

Figure 1. Map of study area: offshore Niger Delta (Adapted from ESRI).
REGIONAL GEOLOGY

The Niger Delta is located at the southern end of the Benue trough and formed from the failed arm of a rift triple junction. This occurred when South America and Africa began to rift in the Late Jurassic; rifting ceased in the Late Cretaceous (Lehner and De Ruiter, 1977). The Benue Trough itself represents the third failed arm of the rift system (Owoyemi and Willis, 2006). Quaternary studies in this area show that if sediment supply was relatively stable, submarine canyons could have been cut and filled repeatedly in the same general area throughout the Tertiary (Burke, 1972).

Structural complexity results from growth faults, shale diapirs, and toe thrusts. Two fold and thrust belts formed in the Tertiary and are still active in some areas. The thrust belts compensate for extensional forces influenced by gravity on the continental shelf. Corredor et al. (2005) divided the Niger Delta into five main structural zones or sections (Figure 2 and Figure 3).

These zones include an extensional area that is characterized by growth faults and rollover anticlines; followed by a shale diapir zone. Continuing basinward, the delta has an inner and outer fold and thrust belt separated by a transitional detachment zone.

Figure 2. Schematic aerial view of Niger Delta structural zones (Corredor et al., 2005).
Figure 3. Uninterpreted and interpreted seismic data of the five Niger Delta structural zones (Corredor et al., 2005).
Stratigraphy

The Niger Delta consists of three main Tertiary formations: the Akata Shale, Agbada Formation, and Benin Formation (Figure 4) (Short and Stäublee, 1965). The Akata Shale is the oldest formation and represents a deep marine depositional environment (Figure 4 and Figure 5). The Agbada Formation overlies the Akata Shale and represents a nearshore environment (Figure 4 and Figure 5). The Benin Formation overlies the Agbada and represents the active deltaic environment (Figure 4 and Figure 5).

![Figure 4. Niger Delta stratigraphic column. The three main study area formations are circled (red) (Modified from Doust and Omatsola, 1990).]
Figure 5. Spontaneous potential and resistivity logs for the Benin, Agbada, and Akata type sections (Short and Stäublee, 1965).

**Akata Shale**

The Akata Shale underlies the entire Niger Delta and reaches a thickness up to 22,000 feet in some areas (Doust and Omatsola, 1990; Evamy et al., 1978; Short and Stäublee, 1965). In the Paleocene, the Sokoto transgression deposited the Akata Shale,
which became the primary source rock for the Niger Delta petroleum system (Doust and Omatsola, 1990). The Akata also contains turbidite sands deposited when the delta was developing and is the most likely location of the turbidite channel for this study (Burke, 1972).

An interesting characteristic of the Akata Shale is its mobility. The shale is under-compacted and over-pressured from the overlying, denser Benin Formation; this combination of factors caused the Akata to intrude the overlying formations creating shale diapirs (Figure 6) (Burke, 1972). These diapirs increase seismic interpretation complexity because they have chaotic amplitude reflection patterns and distort channel features.
Figure 6. Shale diapirs (outlined in blue) intruding overlying beds.
The Agbada Formation underlies the entire Niger delta area and is approximately 10,000 to 12,000 feet thick (Short and Stäuble, 1965; Avbovbo, 1978). Short and Stäuble (1965) approximate the Agbada’s age to be Pliocene to Eocene with the oldest part of the formation in the north and youngest in the south. It is composed of interbedded sandstones and shales. The upper Agbada is dominated by sandstones with fewer shale intervals. The lower Agbada contains more shale beds with minor intercalated sandstones (Short and Stäuble, 1965; Tuttle et al., 2009). Most petroleum in the Niger Delta is produced from the Agbada Formation. It is the primary reservoir and cap rock, with most petroleum extracted from rollover anticlines formed from growth faults (Short and Stäuble, 1965). Evamy et al., (1978), suggested that in some areas lower Agbada shale units are also contributing source rocks.

The Benin Formation is the youngest primary Niger Delta rock unit with an age range from Miocene to Recent. The Benin Formation is present across the entire Niger delta and consists of the present coast line (Short and Stäuble, 1965). It consists of predominantly sand with minor shale intercalations and is described as coarse grained to very fine grained, poorly sorted, subangular to well rounded alluvial and upper coastal plain sands (Short and Stäuble, 1965). Its thickness varies, but may be more than 6,000 feet thick in some areas (Avbovbo, 1978; Short and Stäuble, 1965).
TURBIDITES

A turbidity current is a type of density current initiated by gravity and morphologically resembles meandering rivers in a subaerial environment (Weser, 1977). In some cases, continental shelf sediments build up and become unstable. When failure occurs, these sediments flow down the continental slope and carve out a canyon like feature. However, some density currents are not erosive and only deposit sediment (Bouma et al., 2002). These after formation submarine canyons act as a conduit for turbidity currents and their resulting deposits, termed turbidites. Turbidity currents can also form when sea level drops and exposes the continental shelf. Continental runoff, flows across the exposed shelf and incises into the shelf and continental slope, forming incised valleys (Bouma et al., 2002). Figure 7 shows a simple depiction of a turbidite system.

Figure 7. Turbidite system depiction highlighting it submarine canyon and cross sectional views of turbidite channel deposits. Modified from Bouma et al., (2000).
As turbidity currents flow from the canyon to basin floor they lose momentum and deposit a heterogeneous sediment mixture. Turbidite channels are characterized in seismic data by high amplitude chaotic reflection patterns (Figure 8) (Bouma et al., 1985; Weimer, 1989). Many turbidite systems display stacking patterns with younger channels deposited on top of older channels. Stacked turbidites are known as a turbidite complex and are often important deep water reservoirs because they contain large amounts of sand encased in shales (Bouma et al., 2002; Mayall et al., 2006).

Figure 8. Southwest - northeast crossline 3407 showing recognition of channel by chaotic reflection patterns. The yellow horizon represents the channel top and green represents the base. The vertical scale is in seconds. The index map located in the top right corner of the image shows the crossline location within the survey.

Mayall et al. (2006) explained that turbidite channels are rarely identical, but possess four basic elements consistently which aid in a successful seismic interpretation. These elements are described as the channels’ sinuosity, facies, cut and fill episodes, and
stacking patterns. The configuration of these elements helps determine sand and shale
distribution within the channel.
METHODS

This study is based on a model set forth by Mayall et al., (2006) in which they explain that a turbidite channel is a complex environment that can be broken down into four elements for efficient characterization. These key elements are: sinuosity, facies, cut and fill episodes, and stacking patterns. In addition, the Niger Delta contains shale diapirs which are an added element that needs to be considered for this study. This approach plus attribute analysis will be utilized to characterize the turbidite channel and identify potential reservoirs.

Data Description

The 3D pre-stack migrated seismic data were provided by an anonymous donor. The data set used for this study is missing data in several sections. The entire survey covers approximately 21.8 square miles. The data consists of 576 inlines oriented northeast - southwest and 460 crosslines oriented southeast - northwest. Inline interval was 61.5 feet apart and crossline interval was 41 feet. Due to the proprietary nature of this 3D data the exact location is not known and there was no associated core or well data. As a result, my interpretation is based on reflection patterns, knowledge from previous work, and seismic attributes.

Mapping

The stacked turbidite channel present in the seismic data was analyzed and interpreted using Kingdom SMT 8.5. The chaotic reflection patterns present required manual picking when mapping key horizons. The main channel top, base, and individual subchannels were mapped using a one inline spacing interval. The only horizon not manually picked was a parallel reflector above the channel. This parallel reflector was
picked using 3D Hunt and was used to flatten the data. The 3D Hunt feature interprets a
chosen reflector throughout the entire data set.

Attributes

An attribute is any measurable property of seismic data (Schlumberger Oil Field
Glossary). Attributes were extracted to characterize channel features and for reservoir
identification. The attributes generated and analyzed in this study consisted of Amplitude,
Time, Gain Amplitude, Peak Amplitude, Root Mean Squared (RMS), isochron, and
Sweetness. Peak Amplitude, Gain Amplitude, and RMS attributes are amplitude based
and show differences in reflectivity magnitude related to acoustic impedance change.
Isochrons are time-based and shows thickness between two interpreted horizons.
Sweetness is calculated by dividing the instantaneous amplitude by the square rooted
instantaneous frequency. Areas with high sweetness have been interpreted as areas
containing sand or hydrocarbons.
INTERPRETATION

The main turbidite channel in the Niger Delta data was determined by the termination of parallel amplitude reflectors against a convex downward feature. This feature is filled with chaotic reflection patterns and contains continuous parallel reflectors above and below, which is characteristic of turbidite channels in seismic data (Figure 8 and Figure 9) (Bouma et al., 1985; Weimer, 1989). Mayall et al., (2006) determined their channel base recognizing the same reflection pattern geometry (Figure 10).

Using the planimeter tool, the approximate channel size is 5.85 miles long and 1.67 miles wide, covering an area of 8.25 square miles. Figure 11 and Figure 12 are time structure maps showing regional tilt of the study area with structural highs in the southern portion of the data and lows to the north. The deepest part of the channel is represented by the blue areas in Figure 11. This area contains more accommodation space and

![Figure 9](image-url)
therefore thicker sediments. Figure 13 is an isochron map showing channel thickness with thicker intervals shown in red, which matches the deep areas in Figure 11.

Figure 10. Mayall et al., (2006) defining the turbidite channel based on reflection characteristics. The yellow horizon represents the channel base.

Figure 11. Channel base time structure map. The main channel’s deepest parts are represented by the blue areas and a structural high to the south is shown in yellow and red.
Figure 12. Channel top time structure map. Structural highs are present in the southern section are represented by red and yellows followed by lower areas to the north.

Figure 13. Isochron map showing the main channel thickness. Thicker intervals are represented by reds and yellows and thinner areas by blues.

Project: O_hna
Project Location:
Scale = 1:101300
0 1013 2026 3039 4052 5065 m
Horizon: isochron (hnali) (DeepSkyBlue), Data Type:
Sinuosity

Mayall et al. (2006) postulated four causes of sinuosity in turbidite channels: initial erosive base, lateral stacking, lateral accretion, and sea-floor topography. Although the seismic survey is missing data in some sections, the channel’s sinuosity was resolved and examples of the previously mentioned causes were present. Channel sinuosity was analyzed using time slices, which are horizontal amplitude slices through the data at a chosen time. This provides a map view of the channel (Figure 14). The different episodes of deposition and variation of the density current itself causes the channels to be stacked successively in different patterns. In map view, sinuous stacked channels can resemble a “long box full of snakes” (Figure 15) (Bouma et al., 2002 p. 61).

Figure 14. Time slice at 2.088 seconds showing a map view of the main turbidite channel (outlined in blue) and its sinuosity.
RMS and Peak Amplitude attributes are amplitude based and are often used to infer changes in lithology because variation in amplitude correlate to changes in acoustic impedance. Root mean squared (RMS) amplitude was used to differentiate the channel from surrounding material and was helpful in showing subchannel sinuosity (Figure 16). The yellow areas represent higher amplitude reflectivity which can be inferred as an area containing more sand than the lower RMS values represented by green areas. The Peak Amplitude attribute highlights sinuosity within the main channel and channel cut-offs, known as oxbows (Figure 17). These attributes provide evidence that channel fill sediments are different than surrounding rocks and that subchannels are highly sinuous.
Figure 16. The sinuous turbidite channel (yellow) and surrounding shale (green). Map is an RMS amplitude from a 90ms window within the channel.

Project: O_hna
Project Location:

Figure 17. Peak Amplitude map showing stacked channel sinuosity and meander cut-offs/oxbows.

Project: O_hna
Project Location:
Scale = 1:73717

Horizon: hate attribute (hnali) (Red), Data Type: Amplitudes
Facies

Turbidite channels contain a wide variety of sediments and rock types depending on the nature of the turbidity flow and material derived from the surrounding environment. Mayall and Stewart (2000) proposed dividing turbidite channel fill into four main facies: basal lags, slumps, high net to gross (N:G) stacked channels, and low N:G channel-levee (Figure 18). This approach was chosen because facies distribution is important for reservoir characterization and often recognizable in most seismic data (Mayall et al., 2006).

Figure 18. NW to SE cross section comparing the Niger Delta data (a) and the four main turbidite facies as described by (b) Mayall and Stewart (2000).
Most basal lag deposits consist of coarse sandstones and conglomerates and have a high net sand content (Labourdette, 2007). They generally have higher acoustic impedance than adjacent shales and are distinguished in seismic data as bright reflectors at the channel base (Figure 18a and Figure 19) (Mayall et al., 2006). These lag deposits are the first channel fill deposits following initial erosion and are significant due to their potential as permeable and porous zones to accumulate petroleum (Labourdette, 2007).

Slumps are recognized seismically by weak non-stratified reflections (Figure 19) (Mayall et al., 2006). The area in Figure 18a labeled as a “slump” was interpreted as such due to its dim reflection, lack of bedding, and position near the channel edge. The slump material was likely derived from the channel wall or nearby source (Labourdette, 2007).
The slump facies is important because it can act as a fluid flow barrier and is not an ideal reservoir (Mayall et al., 2006).

The high net to gross facies consists of multiple channels stacking and is recognized on seismic data as a cluster of strong convex downward reflections (Figure 18 and Figure 19). This facies contains mostly sand with possible lags at the base of individual channels (Mayall et al., 2006). The stacked channel facies is the ideal petroleum reservoir facies due to its high sand content and good connectivity. Mayall et al., (2006) used the phrase “axial core” to describe a channel fill with moderate N:G and focused channel stacking (Figure 20). The net to gross distribution shown in Figure 21 is an example of the axial core configuration.

Low N:G channel levees often form the last part of the channel fill and are characterized on seismic data by weak to moderate semi-parallel amplitude reflections (Figure 18a). They contain small sand pockets, but are not ideal reservoirs due to high shale content (Mayall et al., 2006).

![Figure 20. Schematics of stacked channel distributions and associated net to gross percentages (modified from Mayall et al., 2006).](image-url)
Repeated Cutting and Filling

Within the main turbidite channel, smaller subchannels have repeatedly eroded pre-existing fill material and deposited younger sediments (Figure 22) (Labourdette, 2007; Mayall et al., 2006). Quaternary studies show that if controlling conditions were constant, many incision and deposition episodes could have taken place in the same area over an extended period of time (Burke, 1972). In areas that have been cut and filled excessively, older channel remnants may be present. This increases the difficulty of interpretation due to chaotic reflection patterns. Repeated cutting and filling is significant because each episode can affect the reservoir quality and potential (Mayall et al., 2006).

Figure 21. Inline 777 displaying an axial core of stacked channels and moderate N:G as shown in middle box of Figure 20. The chaotic reflections (blue circle) represent the stacked channels.
Figure 22. Inline 908(a) shows the main channel defined by the yellow (top) and green (base) horizons. Image (b) shows the interpreted subchannel bases (blue) within main channel. The amplitude reflection patterns in image (c) show several episodes of cutting and filling by the subchannels.
Stacking Patterns

Stacking occurs when older subchannels are partially eroded and younger sediments are deposited on top or to the side of the previous channel (Figure 23). The base of each successive subchannel is recognized by a high amplitude convex downward reflection. As previously mentioned, stacked channels contain ideal reservoir characteristics and understanding them can aid in a successful evaluation and development of any reserves that may exist (Mayall et al., 2006).

![Figure 23. Stacking of subchannels (blue) within main channel. Subchannels are recognized by a convex downward seismic expression.](image)

Stacking patterns can vary greatly over short distances throughout the channel, but are often generalized into two categories: vertical stacking and lateral stacking.

Vertical stacking occurs when channels are successively stacked directly on top of the previous channel (Figure 24 and Figure 25). Vertical stacking may be related to channel stability and focusing with little to no migration (Mayall et al., 2006); whereas lateral
stacking patterns are produced from channel migration in a particular direction (Figure 26).

Figure 24. Example of a vertical stacking pattern from the Niger Delta data.

Figure 25. Vertical stacking pattern example from Mayall et al., (2006) is similar Figure 24 from the Niger Delta.
Figure 26. Lateral stacking pattern comparison between the study area (a) and (b) from Mayall et al., (2006).
Shale Diapirs

Shale diapirs are present in the data and are recognized as intrusive vertical structures that have low amplitude reflections. Diapirs were formed by the deposition of higher density sands from the Benin Formation on top of the under-compacted and over-pressured Akata Shale (Burke, 1972; Tuttle et al., 2009). This density differential caused the mobile shale to intrude overlying formations, similar to the way salt domes form (Figure 27).

![Figure 27. 3D view of shale diapirs (arrowed). Recognized seismically by intrusive low amplitude reflections. The data cube represents a time interval of 1.7 seconds to 2.5 seconds](image-url)
Shale diapirs disrupt channel morphology and cause chaotic reflection patterns in the data. In the northwest portion of the survey, the main channel is truncated by diapiric structures (Figure 28); furthermore, in some areas the channel is unrecognizable due to the diapirs. The influence of shale diapirs on channel morphology is important for reservoir characterization because they can form localities where oil and gas accumulate. However, they can also have detrimental effects such as destroying previous reservoirs or forming faults that act as leaks.

Figure 28. The channel is truncated in the northeast area by a shale diapir (blue).

**Reservoir Identification**

Using attributes such as, root mean squared (RMS) amplitude, amplitude gain, and sweetness three potential reservoirs were identified. RMS was used to find areas with high amplitude reflectivity because this correlates to areas with high acoustic impedance. High RMS localities were interpreted as areas containing sand and possibly
hydrocarbons. Increasing the amplitude gain was used to locate bright spots and phase changes in the data which are direct hydrocarbons indicators. The sweetness attribute was used to locate areas with high amplitude reflectivity and low frequency which indicates the presence of hydrocarbons.

Reservoir #1

Reservoir #1 is located in the north central part of the main channel and is the largest reservoir (Figure 29). There is a good correlation with the bright spot in Figure 29 and the high RMS response in Figure 30. Inline 815 has high sweetness which matching the amplitude bright spot in the same area (Figure 31).

Reservoir #2

Reservoir #2 is a smaller reservoir located southwest of Reservoir #1 (Figure 32). Figure 33 is an RMS amplitude map that shows a high RMS response in the same area as the amplitude bright spot in Figure 32. Figure 34 shows inline 751 with an area containing high sweetness and two direct hydrocarbon indicators, an amplitude bright spot and phase change.

Reservoir #3

Reservoir #3 is located southwest of Reservoirs #1 and #2 (Figure 35). It was interpreted as a reservoir due to its high RMS amplitude response that matched an amplitude bright spot and high sweetness response in inline 719 (Figure 36 and Figure 37).
Figure 29. Timeslice at 1.996 seconds with increased amplitude gain. Reservoir #1 is the large bright spot within the red square.
Figure 30. RMS amplitude map from 50ms window near the channel top. The high RMS area (red square) matches the high amplitude area in Figure 29.
Figure 31. Inline 815 showing a strong correlation between the amplitude bright spot with a high sweetness response.
Figure 32. Timeslice at 1.996 seconds showing amplitude bright spot with increased gain interpreted as Reservoir #2 (red square).
Figure 33. RMS amplitude map matching bright spot location in Figure 32 (red square).
Figure 34. Inline 751 showing a strong correlation between the amplitude bright spot with a high sweetness response (blue circle).
Figure 35. Timeslice at 1.964 seconds showing a bright spot (red square) interpreted as Reservoir #3.
Figure 36. RMS amplitude map showing a strong response in the area interpreted as Reservoir #3.
Figure 37. Inline 719 showing a strong correlation between the amplitude bright spot with a high sweetness response (blue circle).
CONCLUSIONS

The stacked turbidite channel characterization yielded important information about turbidite channel morphology. It was determined that the main channel contains highly sinuous subchannels and channel cut-offs, also known as oxbows, which can have implications for sand distribution. The main channel’s facies are variable, but four main facies: basal lags, slumps, high N:G stacked channels, and low N:G channel levees can be resolved in the seismic data. The facies are important because they can restrict or allow fluid flow. Within the channel system several subchannels have been successively stacked; most commonly in vertical and lateral patterns which can affect reservoir connectivity. Shale diapirs are present in the data and have disrupted the channel in some areas.

Using attributes such as, amplitude, RMS amplitude, and sweetness three reservoirs were located and recommended for development. These locations were chosen because they contained direct hydrocarbon indicators such as, bright spots, flat spots, and phase changes which matched areas with high RMS and Sweetness values. Applying turbidite channel characterization along with attribute analysis aids in understanding these complex deposits and identifying potential reservoirs.
FUTURE WORK

Computing an Inversion would greatly enhance the interpretation. Inversion is reverse processing that can yield rock properties from the data. Upon finishing the Inversion process, lithologies and their distribution within the channel might be able to be determined. I would also like to compute important attributes such as coherency, curvature, and spectral decomposition, but these are not available on the software package provided by Fort Hays State University Geosciences Department. Well logs and core data would also provide quality control and a means for stratigraphic correlation with the seismic data, but due to the proprietary nature of this data and field area it is not likely to become available in the foreseeable future.
REFERENCES


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