# A "Q" APPROACH TO SEISMIC SOURCE SELECTION

D.Calcagni, S.Giammetti, A.Tansini, ENI Agip Division


## Abstract

In the last years the technical evolution in the geophysical applications for seismic surveys enormously increased the importance of an accurate feasibility study.
Complexity of the surveys implies an interdisciplinary approach to the matter which now involves, in addition to seismic acquisition and time processing parameters design, the evaluation of other possible advanced applications (AVO, PSDM, 3C, 4D, etc.).
For these purpose the most advanced modelling and seismic data processing software are now used by ENI Agip Division Planning Team to obtain a detailed interdisciplinary feasibility study of each single project. Despite of these, some steps of the planning flow still rely on empirical approaches based on field tests.
In this view we studied a way to improve the approach and a workflow able to drive a careful selection of the seismic source parameters for both marine and land surveys.
In particular the energy attenuation due to anelastic absorption is considered allowing to tailor the source to the seismic response of the area in advance of the field effort.


## Introduction

It is well known that the energy of the acoustic wave generated in a seismic survey suffers an attenuation during its propagation in depth. Some of the energy is attenuated due to geometrical condition of propagation (geometrical spreading) and some due to transformation into heat (anelastic attenuation).
The anelastic attenuation property of each rock is summarised by the dimensionless "quality factor Q".
As an intrinsic property of rock, Q represents the ratio of stored energy to dissipated energy.
If the Q value, for the different lithologies, is known it can be applied into ray tracing software's to simulate the effect of the anelastic attenuation in Seismic responses. This will allow a better parameterisation of the seismic source.
During our study several tests have been performed to detect the Q value. Tests are based on seismic data evaluation and on core analyses.

## Work Flow

Based on the result of the study a work flow was defined as illustrated in fig. 1.
The starting point of the flow imply a general knowledge of the problematics of the area.

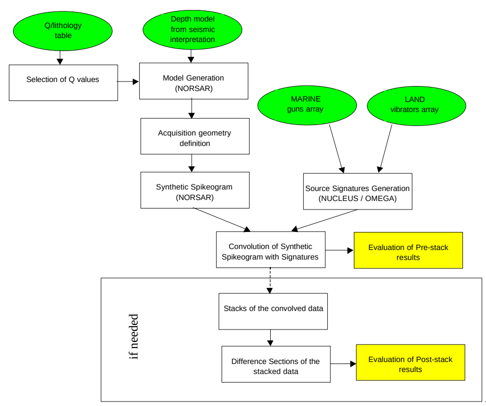

Fig. 1

Flow can be summarised in the following steps:

1. generation of the geological depth model using interpreted seismic section (Norsar SW)
2. selection of consistent Q values to be attributed to the geological model
3. definition of seismic acquisition geometry
4. generation of synthetic shot points spikeogram (Norsar SW)
5. various sources design and relative signatures generation (Nucleus SW for marine and Omega SW for land)
6. convolution of spikeograms with each generated signature
7. evaluation of pre-stack results in shot point or cmp domain
8. stack of the convolved data for each source
9. difference section between the stacked data of each source

# A Q Approach

## Tests on seismic data

Attempts to derive Q from seismic data have been performed using the comparison of the amplitude spectra of a reference signal and a signal (compensated with different Q values) at different depth/lithology.
Measurements have been performed on onshore and offshore data.
All the performed analyses show that a reliable Q value cannot be precisely detected from these seismic data. Too many factors and problems affect the computation.
As an example the amplitude spectrum is directly dependent on the reflectivity coefficient of the layer itself and of all the layers above it.
Energy from layer to layer is sometimes increasing, rather than decreasing, due to higher reflection coefficient (fig. 2).

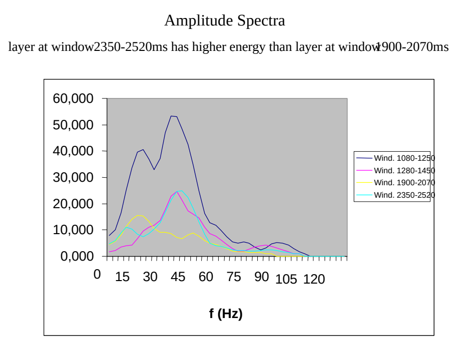


Fig. 2

Onshore and offshore data frequently are affected by:
- low S/N ratio
- ground roll presence
- great difference in seismic response between the two side of the split-spread (fig. 3)
- lack of a reliable reference signal
- strong presence of multiple
- lack of good reflectors for analysis

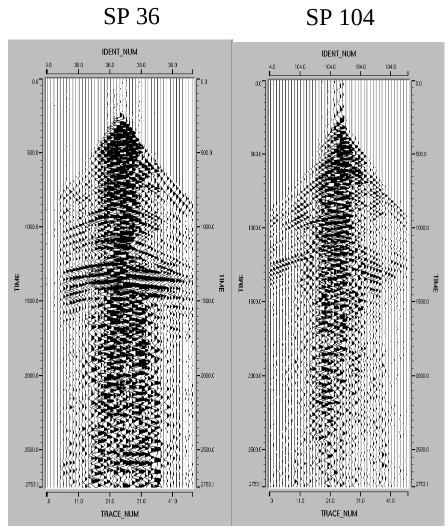


Fig. 3

## Tests on core analysis

As an alternative to the Q computation from seismic data, test were performed by mean of measurements on core samples. Existing tables of Q/lithology were also evaluated.
Q can be derived from core using the following techniques:

| | |
|---|---|
| Hysteresis Loop | 0.01 – 50 Hz |
| Resonant Bar | 1 – 100 Khz |
| Waveform Inversion | 10 –80 Khz |
| Ultrasonic | 700 Khz |

In Eni/Agip Division Laboratories it is possible to perform measurements using the ultrasonic technique. Tests were carried-out on three rock samples:
1 – fine sand core
2 – evaporite core
3 - sandstone core
The results clearly show that the measured values are too similar either for pression or lithology variation.
A careful evaluation highlighted a poor discrimination essentially due to the used computation method (ultrasonic 700 khz). In fact the Q value is frequency dependent and Q values computed with ultrasonic frequencies are not comparable with those computed in the seismic frequency band. On the contrary the other three methods (Hysteresis Loop, Resonant Bar and Waveform inversion) lead to more reliable Q values.

# A Q Approach

In addition to frequency, Q value is also highly variable for porosity, pressure and saturation. These factors increase the uncertainty in Q computation from core analysis.

## Q factor and ray tracing

Based on the above described results, before to proceed with the ray-tracing phase, we decided to build six tables of Q values varying with depth for the more representatives lithologies. These tables were derived from literature of measurements performed using Hysteresis Loop, Resonant Bar and Waveform inversion methods (fig. 4).

Q Table Example

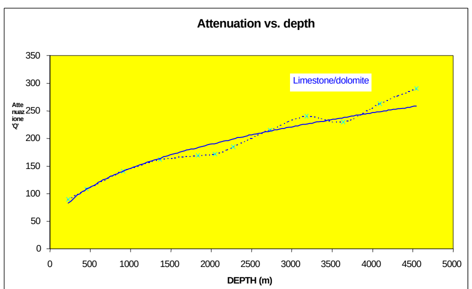


Fig. 4

Consequently, to evaluate as seismic response is influenced by the Q factor several tests were performed on a synthetic geological model.

Three Q values, consistent with the geology of the area, were assigned to three interpreted horizons (Fig. 5) of a marine seismic line and inputed to Norsar ray-tracing software to produce synthetic seismograms.

Synthetic Model with variable Q values

S.P. position

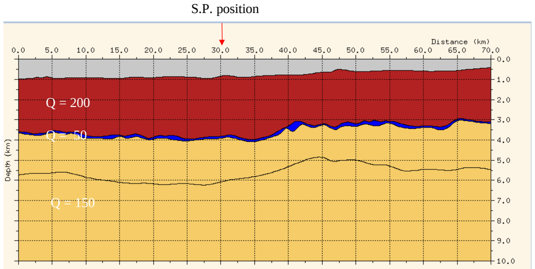


Fig. 5

Analysis of synthetic SP clearly shows the effect of the Q values in reducing the amplitude of the layers, in particular below the intermediate horizon. (fig. 6)

Synthetic S.P. Model

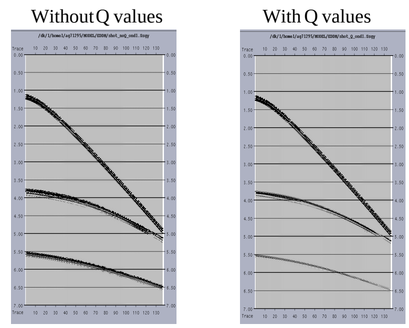


Fig. 6

## Marine Source Design

An appropriate marine seismic source was selected for the model illustrated in figure 5.

As a test case three different energy source volumes (1500 c.i., 3000 c.i.. and 6000 c.i.) were designed in Nucleus SW and their far field signatures obtained.

Norsar SW was used to generate the synthetic spikeogram of the model and to convolve it with the above mentioned far field signatures.

Fig. 7 depicts the seismic response of the three different energy source volumes.

Synthetic S.P. Model with Q values (Far Field Signatures convolved)

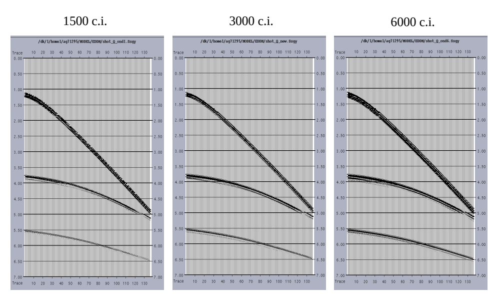


Fig. 7

Two main effects are evidents:

- The general increment in the amplitude for higher source volume which contribute to partially recover the seismic signal attenuated by the anelastic absorption.

- A noticeable ringing effect generated when increasing the source volume.

The final choice of the source volume to be used will must take into account the above results and how they impact on the prospection goals.

### Land Source Design

A parallel approach to the marine source design was tested on a land area including a “blind zone”, due to very bad ground coupling of the vibrator plate, in correspondence of a carbonatic outcrop.
For this example a synthetic model was build and the “blind zone” simulated introducing a highly attenuating Q value in correspondence of the carbonatic outcrop.
Five different vibrator energy sources were then designed and relevant sweeps generated using Omega SW.
The convolution in Norsar SW between the sweeps and the synthetic spikeogram for the blind zone area, is illustrated in fig. 8.

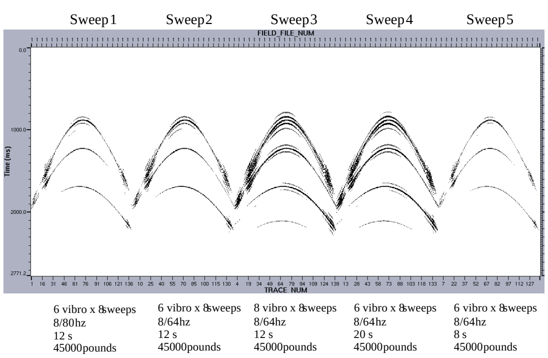


Fig. 8

In the selected example the following aspects can be appreciated:

- a great difference in the five obtained seismic responses.
- a deeper layer visible only using the energy configuration of sweep 3 and 4.
- better seismic response from the sweep 8/64 Hz with respect to the 8/80 Hz.

These results related to the geophysical and geomorphologic characteristic of the investigated area (coupling, s/n ratio, max frequency at target, cost implication, etc) and to the prospection goals will allow a better design of the most appropriate seismic source.

### Conclusions

The performed tests show the extreme complexity to compute the exact value of the Q factor from seismic data.
To meet our goals existing literature Q values have been used to create tables of Q factors varying with depth. The method fully satisfy the accuracy we need.
It is pointed out that the Q to be used must be consistent with the geological model of the area.
The study proved the benefits arising from taking into account the Q factor in the feasibility study. The combined use of the Q factor with the source signature allow to better evaluate the way the seismic source impact on the seismic response.
This approach can drive and consequently reduce the amount of field tests and can reduce the risk of over-engineering of the source with a time and cost save.
As direct consequence it is now available an helpful and cost effective tool, based on analytical result, to better design a seismic source.

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# Environmental Management in Transition Zone Seismic

*Daniella dos Santos Medeiros, GRANT GEOPHYSICAL, Brazil*
*João Bosco Souza Mendonça, GRANT GEOPHYSICAL, Brazil*

**Abstract**

This paper discusses the importance of the implementation of an Environmental Management Program for a seismic acquisition project in Transition Zones in Brazil. It also addresses the results obtained and suggestions for the continuous improvement of the environmental programs to be implemented in future jobs. The environmental management is an essential part of seismic acquisition in Transition Zones - usually highly sensitive areas - and it requires careful planning, training, adequate operational procedures, non intrusive technology and equipment, continuous assessment and a strong commitment at all levels of the organization.

**Introduction**

Seismic data acquisition in Transition Zone is usually undertaken in coastal areas with high environmental sensitivity, where fragile ecosystems such as mangroves, marshes and estuaries are found. In Brazil, shallow water sedimentary basins frequently coincide with feeding, breeding or nesting areas used by protected species, especially marine mammals and chelonians. Besides the ecological sensitivity, operating in such areas usually means interacting with small fishermen communities. Therefore, environmental management projects comprising both the biota and community issues are an essential part of the effort to guarantee that no adverse interferences will result from the seismic acquisition activities.

**The Environmental Management Programs**

A key part of the environmental management concentrates on monitoring interactions with the marine biota during the activities, trying to identify and assess all possible interferences. For that reason, a biota monitoring project is implemented and at least one expert is kept on board at all times during the operation, surveying the area and logging all sights of marine animals, registering their behavior and assessing the degree of interference, if any. Whenever a protected species or a conservation unit is identified in the area a partnerships are proposed to contribute to the knowledge about the species in the area and about the possible impacts of the activity on these animals. Such partnerships have been established with conservation NGO's, universities, government agencies and research centers and the company has provided them with data, equipment, technology and financial support to carry on new research on the impact of transition zone data acquisition projects on particular species.

To assess the issues concerning the communities who live in the areas where seismic activities will take place, a social communication project is implemented from the very beginning of the operations planning. During the planning period all communal associations are identified and company members liaise with their representatives to identify the major needs, concerns and questions. During the acquisition, this cooperative work is maintained and a communication channel is kept open to make sure any doubts or questions concerning the acquisition activities are answered. Also through this program, damage claims are received and compensated. At the end of the job, a questionnaire to assess the degree of interference is applied to at least 5% of the fishermen population of the region.

As most environmental issues are multidisciplinary, there is a strong interface between this program and the biota monitoring program, especially on those issues concerning interferences with fishing activities. Besides the work with the communities, the observers on board responsible for keeping records of all biota sights are also assigned to log interferences with fishing activities, registering all boats contacted, and information such as kind of boat and fishing, species fished and fishing production.

Another important aspect of the environmental management concerns the segregation, adequate storage and correct disposal of all waste generated during the acquisition. Especial attention is put on hazardous waste and on the companies contracted to transport and dispose them. Identifying these companies and facilities making sure they meet all legal environmental requirements is part of the planning activities before the start of the operations. Besides the segregation, the waste management program comprises a strong reuse campaign, in which workers take part not only engaging on the process of selecting, segregating and reusing, but also suggesting new materials and use. An interesting project involved the reutilization of wood waste to build furniture that was both used in the workshop and donated to the community. Whenever present, local recycling facilities are contacted and new projects are supported. A waste log is kept and monthly reports are generated.

Besides any negative interactions with the marine biota and fishing activities, another important environmental aspect that represent a risk are the fuelling activities. Since the vessels used in transition zone acquisitions have small capacity fuel tanks and can work up to 40 hours without refueling depending on the work conditions, the risk of diesel spills during fuelling, if all safety procedures are followed, is reduced and in case a spill would occur the small amount of fuel involved would not cause a significant impact. Although the risks and the possible impacts involved are not significant, the risk has to be managed and reduced by the use of safety procedures and the possible impacts mitigated by the implementation of an oil spill contingency plan.

The contingency plan is designed and constantly reviewed considering the risk scenarios, the products involved and, especially, the environmental sensitivity of the area where the job will take place. Besides the emergency structure and team, the communication strategy, preparedness, and the oil spill containment procedures, a lot of attention is paid on training, involving frequent drills, and to the availability of adequate and sufficient equipment. Both the drills and the equipment are continuously assessed by the teams involved on the implementation of the plan and new procedures are proposed as the plan is reviewed.

To make sure all the plans and programs are correctly implemented a continuous and strong training project is developed along the seismic acquisition work. Besides all aspect concerning the contingency plan, the waste management, biota monitoring and social communications project, a strong emphasis is put on the cultural and environmental sensitivity of the area, natural resources management, energy saving and the Brazilian environmental law.

**Conclusion**

All environmental programs and plans have general and specific objectives and goals and their performance is measure through corresponding indicators. The information about the plans is consolidated in a final environmental report for each acquisition project, which allows the continuous assessment of the performance, objectives, goals, indicators and action plans for each program and, as a consequence, of the environmental management system as a whole.

As a result, the company is able to measure its environmental performance, continuously improving it, to review and establish new goals and, most importantly, it is able to guarantee that its operations are undertaken without causing any harm to the environment or to the communities and in accordance with its environmental policy and the Brazilian environmental law. This reflects positively on the company's environmental licensing process and on its relationship with environmental NGO's, government agencies, community associations and clients.

Considering the increasing concern with environmental issues in business, assessing the environmental viability of a project, designing and implementing an effective environmental management system is an essential part of working with seismic acquisition in transition zones.

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# Licenciamento Ambiental na Aquisição de Dados Geofísicos no Brasil

João Norberto Noschang Neto

Geólogo, Geofísico e Engenheiro de Segurança

Gerente de Segurança, Meio Ambiente e Saúde

PETROBRAS/UN-RIO/ATEX

## INTRODUÇÃO

Este trabalho apresenta a situação atual do licenciamento ambiental para atividade de aquisição de dados geofísicos no Brasil. É apresentada uma síntese do histórico do licenciamento ambiental no Brasil, começando pelo controle da poluição na década de 70. Pela Resolução CONAMA 23/94 não é necessário o licenciamento ambiental da atividade de aquisição de dados geofísicos, porém o órgão governamental tem entendido que é necessário, baseado em uma interpretação muito especial da lei. No mar o IBAMA, através do Escritório de Licenciamento de Atividades de Petróleo e Nuclear tem apresentado às empresas um modelo de Termo de Referência -TR para a realização do Estudo Ambiental, que vem sendo utilizado e adaptado de acordo com a área a ser levantada. Em terra a sísmica tem sido licenciada através dos órgãos regionais de meio ambiente. Este trabalho apresenta as diversas etapas a serem cumpridas no processo de licenciamento ambiental e faz uma análise de prazos mínimos para licenciamento ambiental de aquisição de dados geofísicos no Brasil. O trabalho mostra como a necessidade de licenciamento ambiental torna necessário um planejamento a longo prazo do processo aquisição de dados geofísicos e do processo exploratório.

**HISTÓRICO**

A preocupação com o controle da poluição no Brasil inicia na década de 70. A necessidade de se controlar a poluição causada pela indústria faz com que seja criado o SLAP - Sistema de Licenciamento Ambiental de Atividades Poluidoras. Este sistema faz com que sejam criadas as primeiras leis e decretos neste sentido que passam a balizar o SLAP recém criado. Em um primeiro momento a preocupação e o foco são dados a poluição acidental, principalmente aos grandes centros industriais. Durante a década de 70 cresce a conscientização da sociedade para os problemas ambientais aumentando a cobrança da população quanto ao papel dos órgãos governamentais no controle da poluição. A poluição acidental deixa de ser a única preocupação e são introduzidos nas atividades industriais novos procedimentos, novas técnicas e passa-se a ter uma preocupação com o destino final dos resíduos gerados.

**LICENCIAMENTO AMBIENTAL PARA SÍSMICA TERRESTRE**

O licenciamento da sísmica terrestre passou a ser feito no Brasil pelos órgãos regionais de meio ambiente a partir do início dos anos 90. Estes órgãos entenderam que a atividade de sísmica terrestre seria potencialmente poluidora. O antigo método de se abrir picadas com tratores de esteira colocava a sísmica terrestre no foco dos órgãos ambientais regionais. Mesmo após o abandono deste método de abertura de linha pelas equipes sísmicas, persiste a necessidade do licenciamento considerando-se que:

- em algumas áreas ainda é necessário o uso de tratores de esteira;
- que as equipes sísmicas transportam, armazenam e manuseiam uma grande quantidade de materiais explosivos;
- existe uma grande proximidade com a comunidade;
- são realizados trabalhos em áreas ambientalmente sensíveis.

Além da Lei no.6.938 de 31/08/1981, existem as legislações regionais que apontam para a necessidade do licenciamento da sísmica terrestre.

**LICENCIAMENTO AMBIENTAL PARA SÍSMICA MARÍTIMA**

A indústria do petróleo entende que não existe base legal para *o* licenciamento ambiental da atividade de aquisição de dados geofísicos marítimos. A resolução CONAMA 23/1994 *institui procedimentos específicos para o licenciamento de atividades relacionadas* à *exploração* e *lavra de jazidas de combustíveis líquidos* e *gás natural (EXPROPER).* Esta resolução considera como atividade de exploração / lavra de jazidas de combustíveis líquidos e gás natural:

*- Perfuração de poços;*

*- Produção para pesquisa de viabilidade econômica;* e

*- Produção efetiva para fins comerciais.*

O Escritório para Atividades de Petróleo e Nuclear -ElPN/IBAMA passou, a partir de 1999, a entender que a sísmica marítima é passível de licenciamento ambiental baseado na Lei no.6.938 de 31/08/1981. Anterior a resolução do CONAMA e não específica para as atividades de EXPROPER, esta lei *dispõe sobre a Política Nacional do Meio Ambiente, seus afins* e *mecanismos de formulação e aplicação,* e *dá outras providências.* O art. 10 diz que *a construção, instalação, ampliação* e *funcionamento de estabelecimentos e atividades utilizadoras de recursos ambientais, considerados efetiva e potencialmente poluidores, bem como capazes sob qualquer forma de causar degradação ambiental, dependerão de prévio licenciamento por órgão estadual competente, integrante do SISNAMA, e do IBAMA, em caráter supletivo, sem prejuízo de outra licenças exigíveis.* Somando-se a esta interpretação muito particular da Lei, surge a Lei 9.605 de 12/02/1998 (a *famosa* Lei de Crimes Ambientais). Esta, prevê sanções penais e administrativas derivadas de condutas e atividades lesivas ao meio ambiente. Trata como crime ambiental:

*...fazer funcionar...serviços potencialmente poluidores, sem licença ou autorização dos órgãos ambientais;*

Ampliam-se as dificuldades de obtenção das licenças ambientais a partir do momento em que a Lei 6.605 inclui como crime ambiental:

*conceder* o *funcionário público licença, autorização ou permissão em desacordo com as normas ambientais.*

Além da visão legal é necessária uma análise das repercussões de um acidente com navio sísmico.

Sabe-se que as principais causas da poluição marítima são:

- poluição causada por agentes de terra;

- poluição causada por fenômenos naturais;

- poluição causada pelo tráfego marítimo e exploração *off shore.*

Deve-se considerar que os efeitos e repercussão da poluição marítima são extraordinários, principalmente por óleo. Geralmente são problemas de magnitude transnacional com efeitos imediatos e visíveis, afetando interesse vários. Nestes casos ocorre uma comoção pública, insuflada pela mídia. Nos últimos anos aumentaram os riscos devido ao aumento do *trade* e do tamanho dos navios, inclusive na sísmica. Também, há uma maior valoração dos interesses de meio ambiente.

**O CENÁRIO DO LICENCIAMENTO**

Existem diversos segmentos envolvidos no licenciamento ambiental das atividades de E&P .

Os órgãos ambientais encarregados do licenciamento carecem de dimensionamento adequado para a crescente demanda em função da abertura do setor do petróleo e das necessidades criadas pela legislação cada vez mais restritiva. O monopólio do petróleo exercido pela Petrobras até pouco tempo fez com que os *entendidos* em petróleo estivessem na Petrobras, fazendo com que a capacitação dos órgãos de meio ambiente não seja a mais adequada para a grande demanda. Dificultadores do licenciamento ambiental são, ainda, a falta de agilidade e as amarras legais típicas do modelo de estado brasileiro.

A mudança do cenário de petróleo trouxe ao país novas empresas operadoras na exploração e produção de petróleo. Com elas houve um incremento muito grande na demanda de licenciamento ambiental, além de uma heterogeneidade de práticas, políticas e sistemas de gestão frente às questões ambientais.

A Agência Nacional do Petróleo foi dado o papel, entre outros, de definir a estratégia para o setor petrolífero e criar condições atrativas para uma indústria de petróleo competitiva. Assim esperasse da ANP ações no sentido de facilitar o licenciamento ambiental, fazendo a interface com a área ambiental governamental.

A Petrobras, apesar de entender que não existe base legal, passou a licenciar suas atividades de sísmica *off shore* a partir de junho de 1999.

**LICENCIAMENTO DE SíSMICA NA PETROBRAS**

A Petrobras, apesar de entender que não existe base legal, passou a licenciar suas atividades de sísmica *off shore* usando algumas facilidades criadas pela Resolução CONAMA No. 237/1997 que dispõe sobre o licenciamento Ambiental. Utiliza-se a própria CONAMA 237/1997 para realizar o licenciamento ambiental de sísmica em terra baseado em:

> o *IBAMA... poderá delegar aos Estados o licenciamento de atividade com significativo impacto ambiental de âmbito regional...*

Sempre que possível a Petrobras licencia vários programas sísmicos em uma mesma área e/ou adjacentes baseada em item da CONAMA 237/1997 que prescreve que:

*Poderá ser admitido um único processo de licenciamento ambiental para pequenos empreendimentos e atividades similares e vizinhos..*

Ainda a CONAMA *237/1997* dispõem que os órgãos ambientais governamentais devem criar *...critérios para agilizar os procedimentos de licenciamento ambiental das atividades* e *empreendimentos que implementem planos e programas voluntários de gestão ambiental...*

Esta resolução do CONAMA determina que órgão ambiental tem um prazo máximo de 6 meses para analisar os estudos ambientais ligados ao processo de licenciamento. Para a elaboração do estudo ambiental, baseado no Termo de Referência concedido pelo IBAMA, a Petrobras tem contratado empresas especializadas.

## CONCLUSÕES

O desafio de conviver com o cenário descrito impõe que o processo exploratório das companhias de petróleo considere e se adeqüe aos prazos mínimos necessários para o licenciamento ambiental da sísmica *off shore.*

São facilitadores do processo de licenciamento ambiental:

- sistemas de gestão baseados em normas internacionais como IS0 14001, BS 8800 e ISM CODE.
- conhecimento da legislação;
- planejamento adequado;
- estratégia adequada;
- conhecimento do processo de licenciamento;
- experiência no processo de licenciamento;

- estudos ambientais bem elaborados;
- relação de confiança mútua com o órgão ambiental.

O cenário futuro aponta para:

- restrições ambientais crescentes;
- restrições em Segurança Operacional e Saúde Ocupacional;
- restrições legais crescentes;
- necessidade de parceria com outras operadoras através de órgãos como IBP e IAGC;
- o IBAMA apresentando Termos de Referência cada vez mais restritivos;
- custos de licenciamento crescentes.

# Optimización de parámetros de adquisición mediante el uso integrado del modelado geológico y sísmico: Un estudio 2.5D en el Oriente de Venezuela

*Eugenia Rojas*[1] *y Daniel Mujica*[2]
[1] *Dept. de Ciencias de la Tierra, Universidad Simón Bolívar, Venezuela.*
[2] *PDVSA Intevep,Venezuela.*

**Resumen**

Los diseñadores de levantamientos sísmicos 3D con frecuencia muestran preferencias sobre particulares geometrías de adquisición. Resulta común la diversidad de criterios, acerca de la escogencia del offset, orientación de líneas de disparo, tamaño del bin, entre otros, sobre un mismo objetivo en particular. Cada punto de vista merece ser evaluado técnicamente con un tipo de metodología que nos permita proporcionar una respuesta adecuada acerca de la escogencia correcta de los diferentes parámetros de adquisición en los levantamientos sísmicos.

Se ha generado una cantidad suficiente de registros sintéticos de campo sobre un modelo geológico 3D con variaciones solamente en el plano (*x*, *z*) (un modelo 2.5D); que permite evaluar una variedad de geometrías de adquisición, así como diferentes posibilidades de arreglos de receptores para la atenuación efectiva de ondas de supeficie. Se generó secciones de "zero offset", las cuales fueron migradas en profundidad, utilizando el modelo correcto de velocidades, por un algoritmo de migración por operadores explícitos, con la idea de asegurar que todas las partes del modelo pudieran ser iluminadas de manera correcta, a pesar de la complejidad estructural del mismo.

Los resultados muestran la factibilidad real de modelar la respuesta sísmica del subsuelo con altas complejidades estructurales y estratigráficas, tanto someras como profundas. Así como también, la de evaluar de manera sistemática diferentes parámetros y geometrías de adquisición antes de las operaciones en campo.

## Introducción

Gran parte de las futuras reservas de petróleo se encuentran en yacimientos muy profundos con características de alta complejidad estructural y estratigráfica. La buena imagen sísmica de estos yacimientos es un factor esencial para la mejor caracterización y delineación de los mismos. De ahí, la importancia de establecer metodologías integradas que permitan disminuir el riesgo de seleccionar parámetros incorrectos de adquisición durante las campañas de levantamientos sísmicos 2D y 3D.

La metodología propuesta en este estudio toma ventaja del conocimiento que pueda tenerse acerca del marco geológico del área prospectiva, con el fin de analizar el efecto sobre la respuesta sísmica de características estructurales y estratigráficas presentes en el subsuelo. Seguidamente, al comparar las imágenes sintéticas resultantes, se puede establecer conclusiones acerca de la sensibilidad de la imagen sísmica del subsuelo a la geometría de adquisición propuesta.

En el presente trabajo se ha construido un modelo 2.5D con cambios estructurales importantes en la dirección del buzamiento e invariable en la dirección del rumbo. La secciones 2D utilizadas corresponden a la parte central del Campo Carito, en el oriente de Venezuela, donde PDVSA ha adquirido levantamientos de sísmica 2D y 3D en los últimos años. De esta experiencia, se conoce que las características estructurales presente en el modelo, así como los altos níveles de ondas de superficie, son la causa fundamental de la baja calidad de los datos sísmicos en el área.

Este modelo puede ser visto como un sobrecorrimiento de bajo ángulo, el cual implica la presencia de importantes inversiones de velocidades sísmicas y cuyo estudio permitirá el desarrollo de métodos sísmicos 3D más robustos. Registros de campo sintéticos sobre este modelo 2.5D se generaron mediante el uso de un código de modelado elástico por diferencias finitas. Los resultados obtenidos muestran la factibilidad de esta metodología, la cual permite modelar registros sísmicos en áreas complejas, donde la presencia de ondas de superficie constituyen un elemento de peso en el deterioro de la señal sísmica de interés.

## Marco estructural y construcción del modelo

Durante el Mioceno medio la transpresión de la placa tectónica del Caribe contra la de Suramérica ocasionó el movimiento de la Serranía del Interior y la deformación del flanco norte de la Cuenca Oriental de Venezuela. Esta deformación tectónica del Norte de Monagas, generado por un régimen de tipo compresional, dió lugar a estructuras anticlinales segmentadas en bloques fallados.

Uno de estos bloques se conoce como el área de Carito Central con un estilo estructural dominado por mecanismos de plegamiento del tipo "Fault Bend Folding" en fallas que presentan una geometría despeque-rampa-despegue, tal como se muestra en la Figura 1.

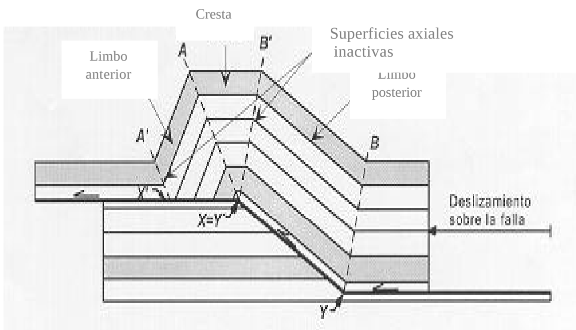


Figura 1 – Estructura geológica que consiste en un pliegue producido por los cambios en la geometría de las fallas.

La Figura 2 muestra un mapa estructural, en el cual se señalan las dos secciones sísmicas donde se interpretan los horizontes y estructuras de interés, a partir de los cuales se generó un modelo geológico 2.5D, representativo de Carito Central, mediante el uso de la herramienta GOCAD. La interpolación de las secciones interpretadas, durante el modelado geológico (Figura 3), respeta la presencia de una falla vertical, la cual se resalta en color rojo en el mapa estructural.

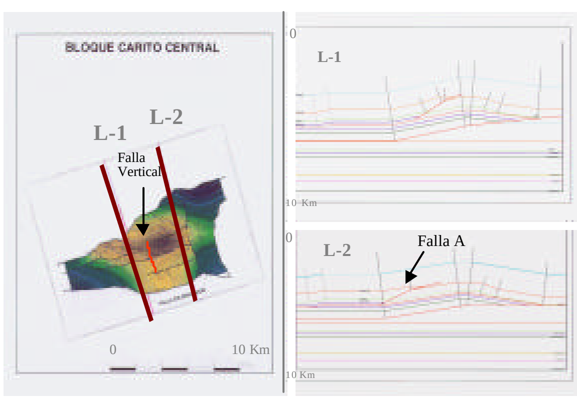


Figura 2 – Mapa estructural con ubicación de dos secciones sísmicas L-1 y L-2, y sus respectivas interpretaciones. Nótese la presencia de estructuras Fault-bend fold en ambos perfiles.

Es importante resaltar que este modelo reproduce la configuración estructural de las secciones interpretadas mostradas en la Figura 2. Adicionalmente, la metodología permite incluir información litológica del área, con el fin de definir regiones cerradas e independientes con propiedades físicas del subsuelo. En el caso particular de este estudio se consideran las densidades y las velocidades Vp y Vs.

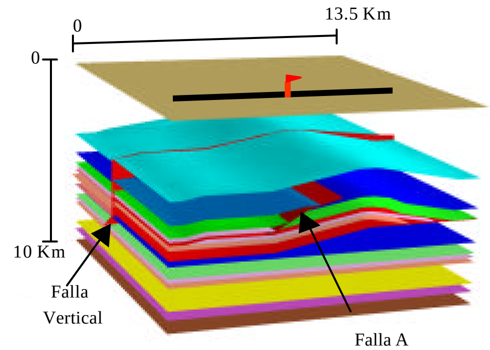


Figura 3 – Modelo geológico 2.5D representativo del Bloque Carito Central generado en GOCAD.

## Suavizado del modelo de velocidades sísmicas

Para producir los datos sintéticos se utiliza un código de modelado elástico por diferencias finitas (Etgen, 1989). Todo tipo de múltiples, reflexiones especulares, ondas compresionales y de cizalla están presentes en los datos. Así como también, difracciones asociadas a eventos estructurales.

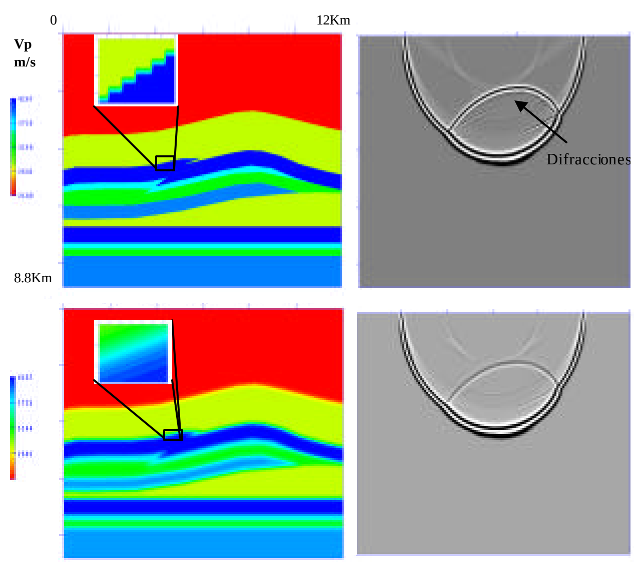


Figura 4a – Modelo de velocidades Vp correspondiente a la sección L1 y propagación de onda asociada a este perfil. Nótese la presencia de difracciones debido a la discretización rectangular requerida por el método de diferencias finitas y el efecto atenuado de las difracciones logrado al suavizar las velocidades.

En la Figura 4a se aprecian difracciones generadas por el operador en diferencias finitas, como consecuencia de la discretización rectangular utilizada durante el modelado sísmico. Para atenuar este efecto, se realiza un suavizado por mínimos cuadrados del modelo de entrada de densidades y velocidades sísmicas. Los resultados obtenidos se muestran en la Figura 4b. Como es apreciable en la figura, el grado de suavizado utilizado no deteriora los rasgos estructurales del modelo geológico original. De ahí, que se preserven en los datos sintéticos, la totalidad de los eventos sísmicos de interés.

### Generación del levamiento sísmico 2D

Se presentan los resultados asociados a una línea de disparo en dirección del buzamiento de la estructura plegada del modelo. La línea consiste de 600 disparos realizados cada 20 m. Con un total de 1200 canales por disparo, configurados en una geometría del tipo "split-spread" y con un espaciamiento entre receptores de 10 m. El offset máximo es de 6000 m mientras que el mínimo es de 0 m. El tiempo máximo de grabación es de 6.5 s con una rata de muestreo de 1 ms (debido a las condiciones de estabilidad del operador en diferencias finitas).

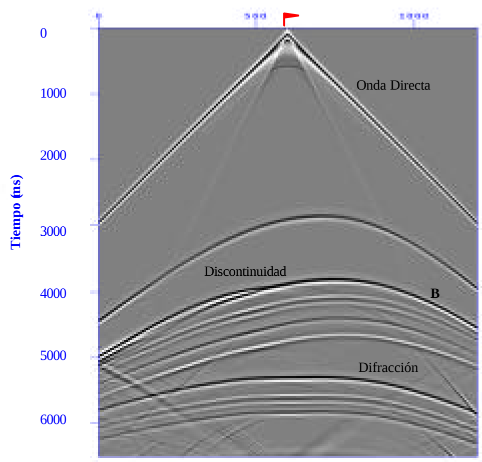


Figura 5 – Registro sintético con la presencia de los eventos sísmicos asociados al perfil L1. Nótese la presencia de una discontinuidad en el evento B debido a la presencia de la falla A en el modelo.

La Figura 5 muestra un disparo calculado en la parte central del modelo. Las interpretación de los eventos sísmicos permite verificar las validez de los parámetros de adquisición escogidos, dada la iluminación correcta de los diferentes eventos estructurales del modelo. En particular, es apreciable la difracción (evento sísmico a los 4 s en la traza 500) asociada al plano de falla ***A*** en el modelo. Más aún, es notable la falta de continuidad del evento sísmico ***B*** debido al desplazamiento de los estratos por presencia de la falla anteriormente mencionada. Otro aspecto de interés son las reflexiones sísmicas por debajo de los 4.5 s la cuales están asociadas a horizontes con profundidades mayores a los 6 km.

### Generación del Ground Roll

En el área de estudio resulta de gran importancia entender el fenómeno de propagación y atenuación de ondas de superficie. Experiencias anteriores han demostrado que la señal sísmica de interés se encuentra enmascarada por altos niveles de ruido coherente que generalmente se propagan en diferentes direcciones en la superficie o capas someras. Se ha reportado que este tipo de ruido puede alcanzar niveles de amplitud por encima de 30 dB de la señal de interés (Regone, 1997).

A continuación, se presenta una aplicación en dirección de la mejor comprensión del fenómeno anteriomente mencionado. En la parte somera del modelo 2.5D se definen cuatro estratos planos cada uno con espesores de 10 m, 10 m, 20 m, 20 m y con velocidades Vp iguales a 842 m/s, 1900 m/s, 2121m/s, 1845 m/s respectivamente (ver Figura 6a).

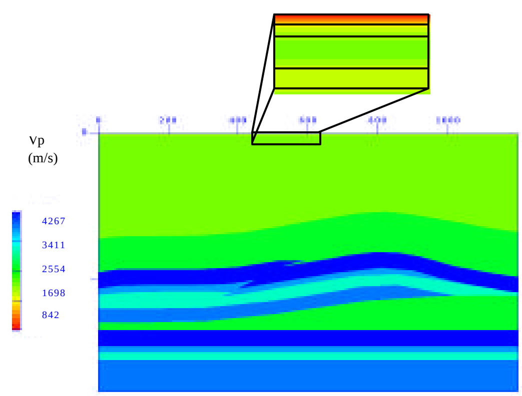


Figura 6a - Modelo de velocidades Vp donde se distinguen las capas finas incluidas con la finalidad de generar ground roll.

La definición de estas capas tienen la finalidad de originar en los registros sintéticos la presencia de "ground roll" (Ata, 1993). El registro sintético de la Figura 6b muestra el resultado, donde son apreciables tres modos propagación asociados al "ground roll".

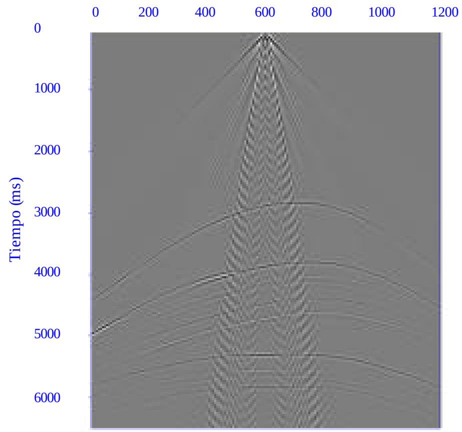


Figura 6b – Registro sintético donde se observa la presencia de "ground roll" sobre los datos sísmicos de interés.

El resultado muestra la capacidad de generar ondas de superficie con la metodología propuesta. Adicionalmente, es posible verificar la efectividad de diferentes arreglos lineales de receptores en la atenuación de este tipo de ruido coherente, dado que se disponen de suficientes disparos en el estudio presentado.

### Migración en profundidad de la sección "zero offset"

Las Figuras 7 y 8 muestran las secciones apiladas y migradas en profundidad respectivamente. Para realizar la migración sísmica se ha utilizado el modelo correcto de velocidades. Estos resultados demuestran que la complejidad estructural del modelo puede ser resuelta por métodos de sísmica de superficie. De ahí, la validez de la metodología propuesta para la escogencia óptima de parámetros de adquisición en el área de estudio.

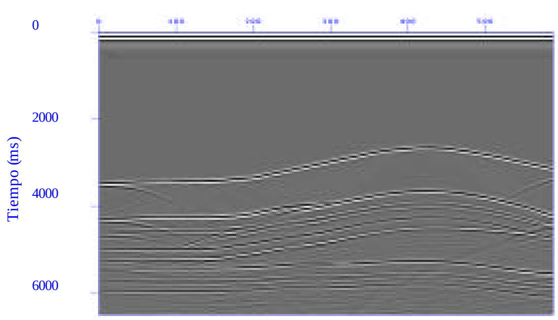


Figura 7 – Sección apilada de "zero offset" . Nótese las difracciones asociadas al plano de falla presente entre las trazas 200-400 por debajo de los 4 segundos.

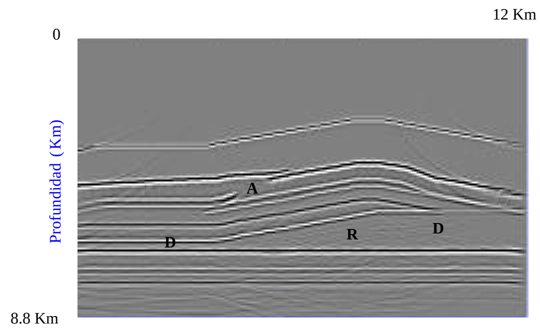


Figura 8 – Sección sísmica migrada en profundidad. Nótese la iluminación correcta del plano de falla ***A*** y de la zona de despegue-rampa-despegue (**D-R-D**).

### Conclusiones

En este trabajo se ha presentado una metodología cuyos resultados pueden ser utilizados para la escogencia óptima de parámetros de adquisición en el área de Carito Central. Se generaron suficientes registros sintéticos, que incluyen la presencia de ondas de superficie ("ground roll"), sobre un modelo geológico que presenta rasgos estructurales de importancia en el área. A partir de estos resultados, se puede establecer la sensibilidad de la imagen a diferentes parámetros y/o geometrías de adquisición. Disminuyendo así la posibilidad de realizar una escogencia errónea de los mismos.

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### Agradecimientos

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# Optimization of acquisition design based on common reflection stack

*Toshi Chang*, Luis Canales, Chih-Wen Kue, Chung-Chih Shih, WesternGeco*


**Summary**

A seismic acquisition survey should be designed in a way that fulfils the imaging requirements while satisfying the economical constraints. Common Reflection (CRP) stack on the surface is able to describe the true amplitude on the subsurface. The computed forward modeling based on CRP can be done efficiently by using wavefront construction with two-point raytracing(Chang, Downie, 1995, 1996; Chang, et al., 1997, 1998). The synthetic amplitude information in the subsurface can also be put on the surface based on the raypath information in the presence of complex subsurface. The main contribution of this work is to provide theoretical amplitude attributes based on CRP stack on both the surface and target horizon for complex models. These attributes can provide the valuable information for an acquisition layout and an appropriate depth imaging sequence. Ideally, the receivers should be placed on the area with maximum energy return as shown in Figure 1.

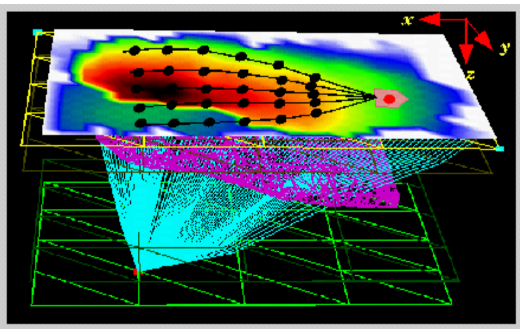


**Fig. 1. Acquisition design with the receivers placed on the area with strong energy returns.**

The layout also gives a first amplitude map based on a given 3D geological model and then we are able to propose a better seismic acquisition layout.

The main motivation for this research comes from the need for good acquisition parameters over complex salt structures. There is a high contrast in velocity between the salt bodies and the surrounding sediments. The difficulty of imaging salt dome flanks with 3D seismic surveys may be the result of our inability to precisely predict the lateral variation of velocity fields adjacent to the salt. Poor subsalt imaging may be caused by poor acquisition design. For traditional model based acquisition design using common shot gather (CSP) raytracing, it is difficult to provide the coverage in the "blind zone". Because we illuminate the reflector by putting the point source on the target horizon, we are able to provide the amplitude information both on the surface and the target horizon. This, in turn, increases the accuracy and efficiency of acquisition planning and the validity of the depth model. Two simple synthetic models are used to demonstrate the concept of illumination based on CRP stack. A sophisticated salt dome model from a Gulf of Mexico data set was then constructed to demonstrate the technique on a more realistic and geologically interesting structural model.


## Introduction

Traditional 3D data acquisition design has mostly been an empirical process. It is almost entirely based on parameters, such as bin size, fold coverage, offset distribution etc. These are not sufficient to determine the ultimate image of the earth model. Relatively simple survey designs are effective in areas with flat or gently dipping layering. In the presence of complex structures, however, wavefield behavior becomes difficult to analyze. Forward modeling algorithms might be able to simulate the wavefield propagation with multivalued arrivals However, up-to date Kirchhoff pre-stack migration algorithms will not migrate multivalued arrivals. The weak amplitudes reaching a receiver will most likely be masked by ambient arrivals with stronger amplitudes, and those will not bring valuable constructive information to the migration process. The seismic data with weak amplitudes are therefore usually susceptible to noise because of small fold coverage and the presence of "blind zones."

The extension of forward modeling from processing and interpretation to acquisition would seem to be a natural and useful development. However, in order to better understand the 3D survey design, we should have a CRP modeling system that can simulate a complete survey and give much better information on illumination, offset distribution, location of the "blind zones." These parameters can be used to setup a strategy for data processing. The amplitude maps and the corresponding acquisition sampling can be used to optimize the acquisition parameters, control the quality and minimize the cost of the survey.

### Method

Normal Incident (NIP) Raytracing

From each sample on the target horizon, we shoot a normal incident ray up to the surface, which intersects the surface at a point(x,y,z).

Wavefront Construction

A point source is placed on the target horizon and an initial wavefront is generated. The wavefront propagates upward along the NIP raypath. The wavefield is handled by the locally smooth, recursive subdivision method (Chang and Downie, 1995). After the wavefield arrives at the surface, a multi-valued wavefront is generated. We are searching for the minimum traveltime based on Fermat's principle with maximum energy at the receiver(Chang, et al., 1998). The energy is calculated based on the law of energy conservation and the law of intensity of light (Gershon, 1994).

Common Reflection Stack

For each grid on the surface, we are able to retrace to the shot point along the raypath on the target horizon. Therefore, we can generate the amplitude on each surface grid for each shot point on the subsurface. The total energy at the surface should be equal to the energy on the point source of the target horizon based on the law of energy conservation. After we shoot all the samples on the target horizon and stack all the amplitudes on each grid on the surface, we are able to obtain the amplitude maps on both surface and target horizons.

**Examples:**

Synthetic model

The following two examples illustrate why CSP model based acquisition design will be unable to cover "blind zones" on a complex geological model.

A simple synthetic model as shown in Figures 2 and 3 is first used to demonstrate the concept of CRP stack for the acquisition design. We simulate CSP shooting by placing both shot point and receivers on the surface. After exploding a single shot on the surface, we are unable to illuminate the "blind zone" in the syncline area of the target horizon because the receiver is searching for the maximum energy from multivalued arrivals as shown in Figure 2.

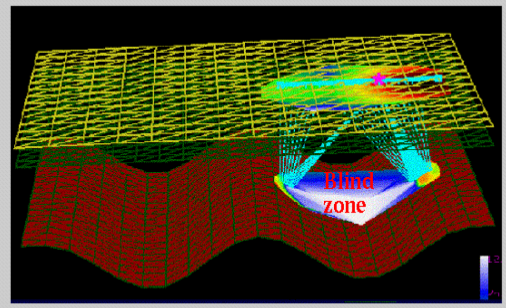


Fig.2. CSP shooting producing the "blind zone" on the target horizon.

If we simulate CRP shooting by placing the shot point on the target horizon, we will prevent the "blind zone" on the target horizon, as shown in Figure 3.

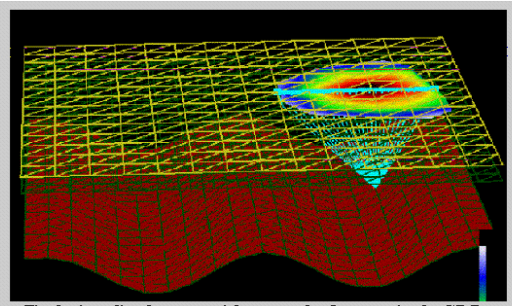

Fig.3. Amplitude map with raypaths from a single CRP set of rays.

Next, we simulate CRP shooting on the target horizon and stack all the amplitudes for each shot point. We repeat the same procedure for all the shot points on the target horizon. After shooting, we stack all the amplitudes on each grid on the surface and generate the amplitude maps both on the surface and the target horizon, as shown in Figure 4.

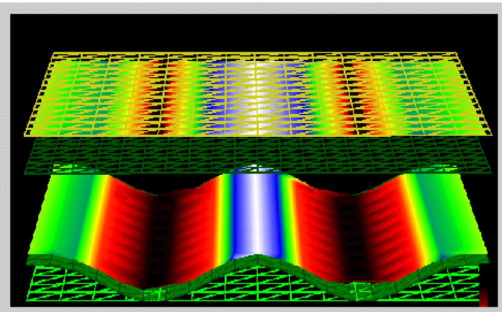

Fig.4. Amplitude maps from CRP stack both on the surface and the target horizon.

In this synthetic model, we are able to generate the amplitudes in the "blind zones."

The salt diapir model, shown in Figure 5 demonstrates that the traditional rectilinear nature of a seismic survey will fail to provide the necessary information for proper data processing and interpretation on the diapir model. Theoretically concentric 3D shooting should be able to provide high quality data coverage. However the most difficult part of the acquisition design for this model is to determine where to put the shots and receivers, the cable length and bin size necessary to the flank of the salt diapir. With traditional shooting geometry, the weak amplitudes along the salt flanks will most likely be masked by the strong amplitudes from the surrounding sediments. However, If we simulate the CRP shooting on the area we are interested in, we are able to precisely obtain the valuable information even with weak amplitude. Figure 5. shows the amplitude map from a single shot on a flank of the salt diapir.

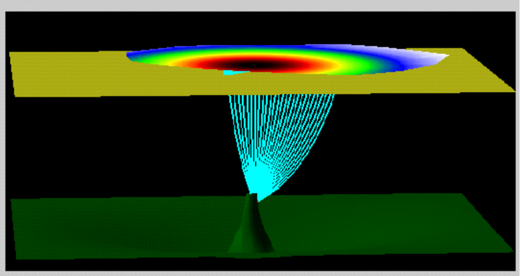

Fig. 5 Salt diapir with amplitude map on the surface generated from a single CRP on the target horizon.

After implementing CRP shooting for all the grid on the target horizon and stacking the amplitudes both on the surface and the target horizon, as shown in Figure 6, we are able to easily design the shooting geometry for this model.

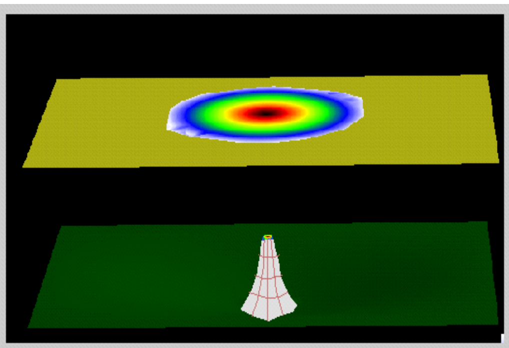

Fig.6. Salt diapir model with CRP stacks both on surface and target horizon.

**Example:**

Gulf of Mexico salt model

The purpose of this example is to demonstrate the new approach on a complex salt model from the Gulf of Mexico. There are 10 sedimentary horizons with 4 salt bodies in this model. First we simulate the traditional CSP shooting. The four receiver lines move from south to north simulating the towing of streamer cables behind a seismic vessel. The cable length is 6 km and the receiver spacing is 100 m with 60 receivers in each cable. Forward CSP modeling of 2250 common shot gathers was performed.

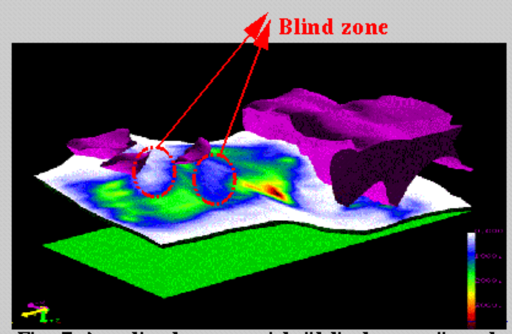


Fig. 7 Amplitude map with "blind zones"on the target horizon based on CSP shooting.

Figure 7 shows the amplitude map on the target horizon. We found several “blind zones”. Next, we implement CRP stack on the same model. We explode each grid on the target horizon and implement CRP forward modeling. After the wavefields arrive at the surface, we stack all the amplitudes belonging to the same location on the surface.

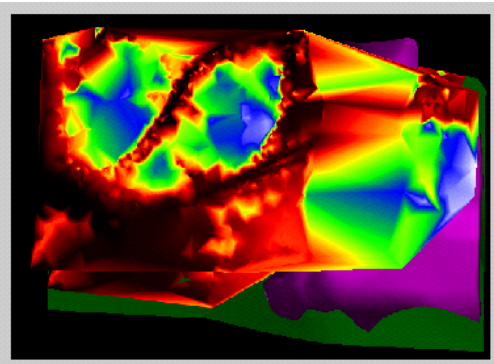

Fig. 8. Amplitude map on the surface based on CRP shooting.

Figure 8 shows the amplitude map on the surface, which can be used to analyze where to place the shot point and receivers in order to record valuable information from the target horizon.

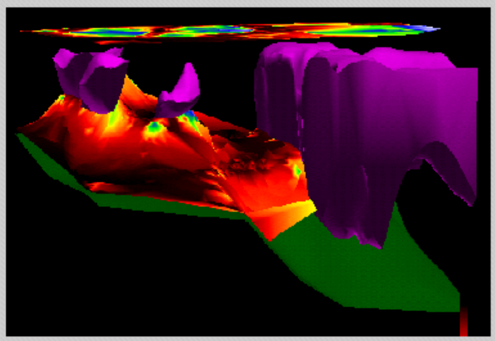

**Fig.9 Amplitude map on the target horigon based on CRP shooting.**

Figure 9. shows the amplitude map on the target horizon. The "blind zones" shown in Figure 7 have almost disappeared. After analyzing both maps, we are able to optimize the cable length and bin size to obtain the best survey design.

## Conclusion

We have proven that CRP stack model-based illumination is an efficient way to optimize the shooting geometry. It gives illumination results both on the surface and the target horizon based on the amplitude maps. The amplitude map on the target horizon can be used to compare with the output of prestack migration to control the quality of the processing sequence. The amplitude map on the surface shows where the receivers should be placed for optimum illumination. Considerable cost reduction can be achieved by CRP stack modeling while still preserving valuable amplitude information in the difficult areas to image. This, in turn, allows more precise identification of hydrocarbons on the flanks of salt bodies and leads to an increase in confidence in the data processing and interpretation results.

## Acknowledgment

We gratefully appreciate the support and encouragement of WesternGeco in providing the resources that enabled the investigation of this method. We also thank Mr. Glen Denyer from EEX Corporation for providing the model data.

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# Optimizing surface marine acquisition patterns for seismic signature estimation from direct waves

*Adelson S. de Oliveira, Angela C. Romero Vasquez e Marcia C. Martins Vieira PETROBRAS S/A, Brazil*

**Abstract**

In this paper, we discuss the constraints to be imposed to marine acquisition pattern design so as to optimize the results of a source signature estimation method that uses direct waves. These constraints aim at assuring that the direct waves exhibit a full and reliable coverage of the signal bandwidth, allowing for an estimation of the source signature that better accomplishes deconvolution. It is found that an appropriate acquisition pattern design would demand no further development of technology and is economically and logistically contained in the current practices of marine seismic surveying. In fact, in most marine surveys, after deconvolution of the pulse obtained from direct waves, seismic data suitably matches exploration and reservoir characterization demands for a usual reflection target with frequencies up to 50 Hertz. Some marine surveys pose no problems for higher frequencies. An example of an improperly acquired seismic dataset, processed after the deterministic deconvolution considered here and after the conventional spiking deconvolution, is presented. For the sake of comparison, analogous results from a regularly acquired dataset is also shown.

**Introduction**

Over the years, many attempts have been made to achieve the goal of determining the source signature for deconvolution purposes. Among deterministic approaches, we consider the use of direct waves as a source of information for signature estimation. In deep water surveys, direct waves are usually free from any reflection interference, thus allowing for an independent determination of the source spectra and instrument impulsive responses that make up the acquisition apparatus (Oliveira et al., 1991). Actually, direct and reflected waves carry information about the same acquisition apparatus' frequency spectrum except where their directivities give rise to distinct notches. Ideally, the direct wave should have no notch in the entire reflection recoverable bandwidth. However, coincident notches are acceptable.

Notches have different origins in direct and reflected waves. Ray trajectories in direct waves are almost horizontal as opposed to reflection rays that are practically vertical. As a consequence, direct wave notches are essentially related to the lengths of source and receiver arrays, while reflection notches are a result of array depths. Typically, array design features are such that, for any reflection seismic data under 50 Hertz, the estimation and deconvolution of a pulse extracted from direct waves works well. But, there are some remarkable exceptions in which the first direct wave notch may appear at frequencies smaller than 40 Hertz. Nevertheless, to avoid this undesirable exceptions and even extend the reliable bandwidth till high resolution needs, no technological breakthrough is required. In principle, direct wave notches depend on the geometrical disposition and nominal cubic capacity assigned to each of the individual sources in the array, and on the receiver array design. Source arrays are usually designed to provide enough energy for illuminating targets and also to minimize the bubble generation. Since each of the airguns exhibits different notionals (Ziolkowski et al., 1982) that changes as a virtually undetermined function of the source array, it is rather difficult to assess from simple arguments any precise prescription of what a proper source array should look like. However, from current experience it is safe to say that an optimal solution exists which is characterized by a weak enough bubble with a broader enough direct wave frequency spectrum, and that this solution means an array that is nothing but quite commonly used.

**Source and receiver array design**

The seismic pulse estimation method considered here makes a simple assumption concerning the behavior of airguns in a real seismic acquisition apparatus: In a real seismic acquisition apparatus, one can approximately write

$$n_i(t) \approx C_i\, n(t), \qquad (1)$$

where $n_i(t)$ stands for the notional (Ziolkowski et al., 1982) associated with the $i$-th airgun as a function of time $t$, $C_i$ is the cubic root of the cubic capacity in the $i$-th airgun, and $n(t)$ is a unitary cubic capacity equivalent notional (Oliveira, 1998). This makes it possible to estimate the whole effect of source/receiver array via the expression below:

$$A(x,t) = \sum_{i,j,\alpha} C_i\, \varepsilon_\alpha \frac{\delta(t - t_{ij}^{\alpha})}{4\pi\, R_{ij}^{\alpha}} \qquad (2)$$

where $\delta$, $x$, $t_{ij}^{\alpha}$, $R_{ij}^{\alpha}$, $\varepsilon_{\alpha}$, and $A$ are respectively, the Dirac's delta function, the offset, the travel time from the *i*-th source to the *j*-th receiver following $\alpha$ path, the travel distance from the *i*-th source to the *j*-th receiver following $\alpha$ path, a constant that assumes values of +1 or –1 according to the number of surface reflections (ghosts) in a given $\alpha$ path, and the array effect. Notice that direct and reflected waves have basically different sets of $\alpha$ trajectories.

A brief discussion on the validity of the above assumption could begin with the observation that notionals do vary essentially only on the bubble window (Oliveira, 2000). Indeed, the main airgun's pulse is much like a spike with amplitude proportional to the cubic root of the airgun cubic capacity, in agreement with (1). Furthermore, source arrays are designed to attenuate bubbles. Typically, a peak-to- bubble amplitude ratio may be as high as 12. Thus, as long as the main pulse is the only concern, the approximation (1) holds.

Let's consider, for the sake of simplicity, that an array is made up of airguns with $C_i \propto R_{ij}$ and only one receiver (*j*=1). Let's further admit that the array's depth is much smaller than the offset so that direct wave notches are fully controlled by the source array length. In this case, we expect the first notch to appear at a frequency given by,

$$f_1 = {}^{v}\!/_{d}, \tag{3}$$

where $f_1$ is the frequency of the first notch, $v$ is the sound velocity in water and $d$ is the distance between the first and the last airguns. For a typical sound velocity in water of $v$=1540 meters per second, the first notch is expected to be beyond 125 Hertz if $d$ < 12.3 meters. If a receiver array is used, the whole array frequency spectrum will be the product of source and receiver array contributions. Thus, for a receiver array length of no more than 12.3 meters, we expect no notch for a direct wave frequency spectrum till 125 Hertz. This is completely contained in typical acquisition practices, and could be applied for most marine surveys. If this care is taken during acquisition the estimated notional will show no lack of frequency information. Therefore, one can recover a much broader reflectivity bandwidth.

## Real Data examples

The technique for pulse estimation and deconvolution using direct waves was applied for two different seismic surveys, called survey one (S1) and survey two (S2). In S2 the acquisition pattern was

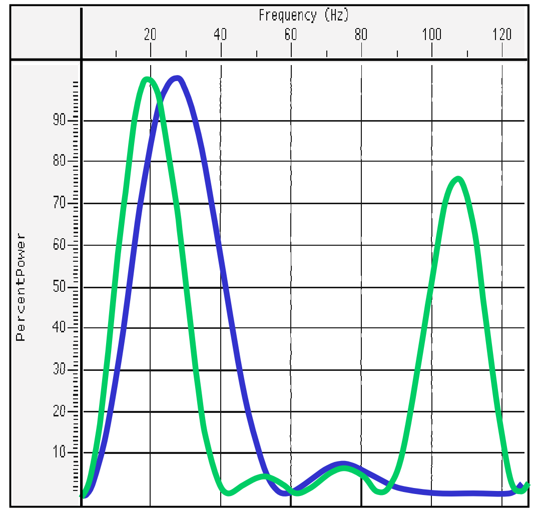


Figura 1 – Survey one (blue) and two(green) direct wave array's frequency spectra. Note that the first notch for S1 is nearly at 60 Hertz while for S2 is around 40 Hertz.

such that an overwhelming limitation in the direct wave frequency spectrum (see figure 1 for a comparison between S1 and S2) brought the highest recoverable frequency up to only 40 Hertz. In S1 this limitation is not that severe being the highest recoverable frequency around 60 Hertz. Figure 2 shows a window of a seismic section of S1 by the sea bottom containing (left) the result after deconvolution of the pulse obtained from the direct wave and (right) the result with conventional spiking deconvolution. From the comparison between left and right figures it can be easily noticed that some events have been damaged in continuity and resolution after spiking deconvolution. These are examples of the kind of problems the statistical approach usually brings about as a result of non-whiteness of the reflectivity. Figure 3 shows an analogous example with S2. Now, as a result of the lack of information on the direct wave's frequency spectrum, the performance of the deterministic deconvolution approach (left) is much worse in this window, when compared to the spiking deconvolution process (right). These problems are not observed if frequencies higher than 40 Hertz are not present. For deeper events the frequency content is naturally more restricted and, as expected, the advantages of a deterministic approach over the statistical spiking deconvolution are again observable. Figures 4 and 5 exhibit the results with S1 and S2 in a deep reflection.

# Optimum array pattern for pulse estimation

## Summary and Conclusions

In this paper it is proposed an additional restriction to current acquisition practices in order to assure a broader direct wave frequency spectrum. It is shown, from simple arguments, that this restriction is neither economically nor logistically demanding and that it can guarantee a much better estimation of the seismic pulse from the direct wave.

The impact of an improperly designed acquisition pattern on the estimation and deconvolution of a seismic pulse using direct waves, is demonstrated via real data examples. Essentially, the impact is a severe frequency band limitation on the recovered signal. However, it is expected that for lower frequencies (up to 40 Hertz) this procedure is safe, even for a very inadequate acquisition pattern.

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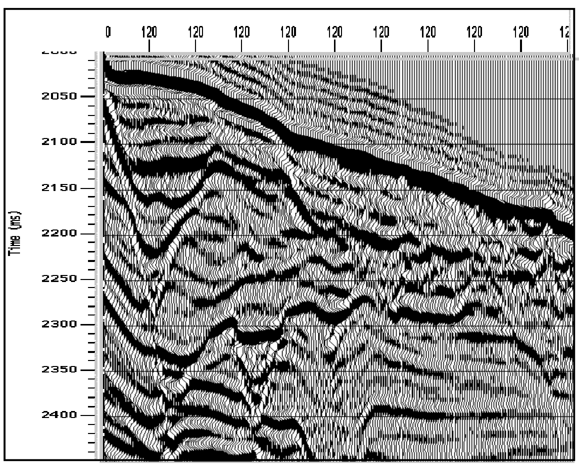
## Acknowledgments

We would like to thank PETROBRAS for permission to publish this work.



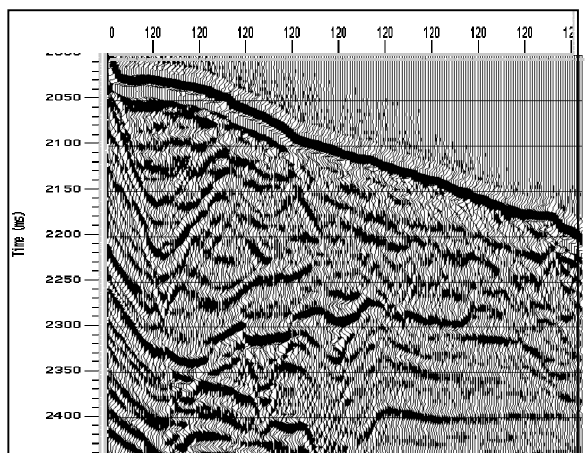
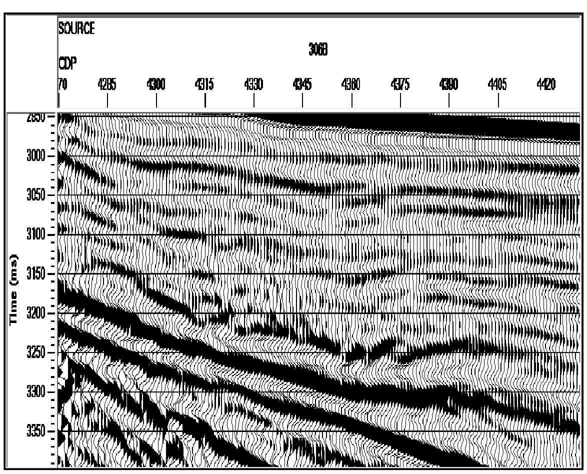




Figure 2 – A window by the sea bottom with S1 data processed with deterministic decon (left) and spiking decon (right). Notice the improved resolution and continuity of the events on the left section.



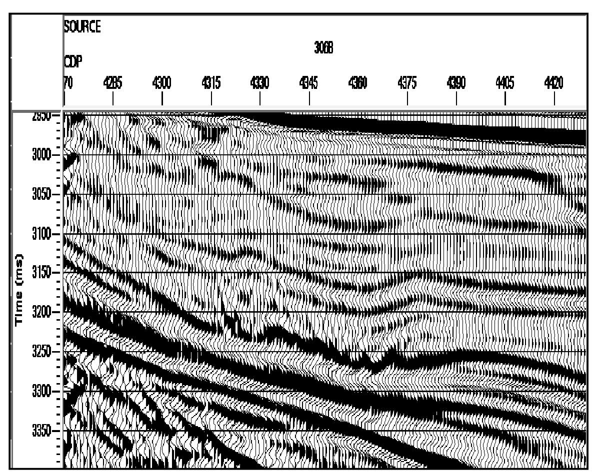




Figure 3 – A window by the sea bottom with S2 data processed with (right). Noticed how events around 3150 ms and above are dimmed bandwidth on the left section.

Figure 3 – A small window by the sea bottom with S2 data processed with deter decon (right)

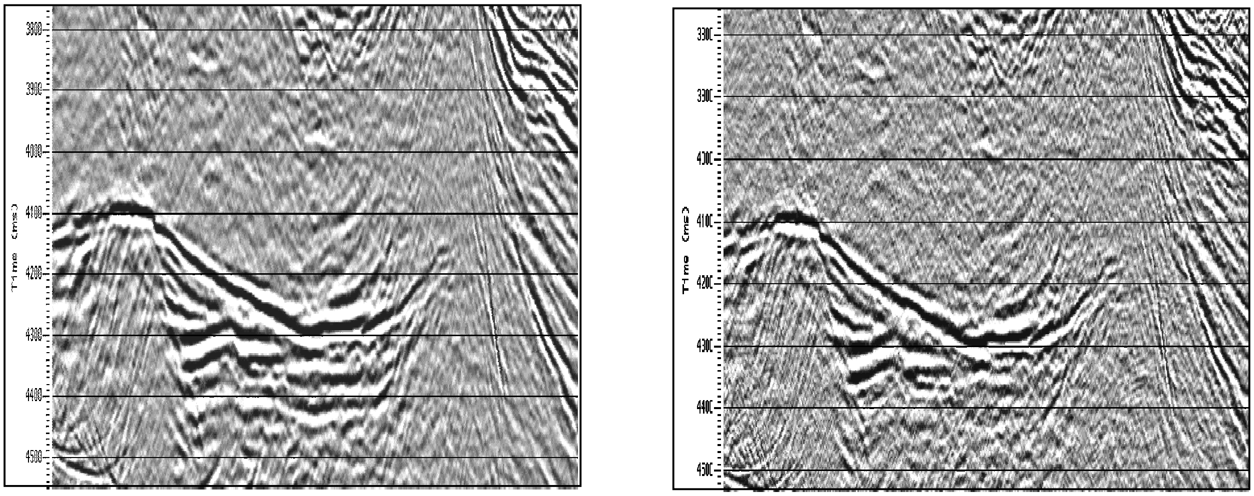



Figure 4 – A window showing a deep target in S1. Data processed with deterministic decon (left) and spiking decon (right). Notice that the statistical approach has damaged the non-white component of the reflectivity around 4400 ms.

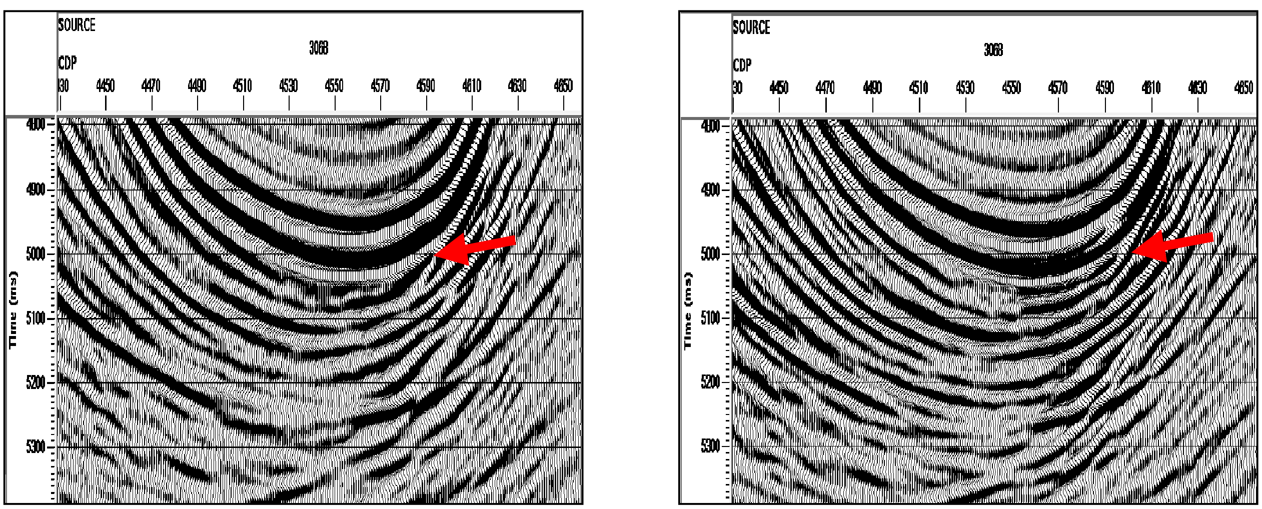



Figure 5 – A window showing the bottom of a synclinal in S2. Data processed with deterministic decon (left) and spiking decon (right). Notice (the red arrow) that the truncation is better preserved in the left section when compared to the right one.

# Single and Multi-component Seismic Acquisition in Shallow Water and Transition Zone Environments

*Ewan Neill, GRANT GEOPHYSICAL, USA*
*Lee Parker, GRANT GEOPHYSICAL, USA*
*Hugh Shields, GRANT GEOPHYSICAL,USA*
*Carlos Alberto Poletto, PETROBRAS S/A, Brasil*
*Odilon Keller Filho, PETROBRAS S/A, Brasil*
*Jorge Fiori Fernandes Sobreira, PETROBRAS S/A, Brasil*
*Sergio Campos de Souza, PETROBRAS S/A, Brasil*
*Marcos A. Gallotti Guimaraes, PETROBRAS S/A, Brazil*

## Abstract

In the last two years, Grant Geophysical has acquired several transition zone datasets in the Potiguar Basin in northeastern Brazil, using single hydrophones offshore and geophone arrays onshore. The techniques to acquire data in very shallow water and through the transition zone safely and in harmony with the environment are necessarily different from conventional OBC. While single sensor data has proved adequate to image the gross reservoir formation, the lack of a P-Wave impedance contrast between sub-strata of the formation has precluded the ability to resolve them clearly. In combination with Petrobras, we designed and acquired an experimental 4-component acquisition test, the first to be conducted in Brazil. Two orthogonal 2D lines were acquired using fully gimbaled 4-component receivers deployed on the sea floor. Preliminary results indicate that the hydrophone data is of similar quality to previous single hydrophone data. The vertical geophone suffers from severe ambient noise in the very shallow water but provides acceptable data in water depths beyond 2m to 3m. The horizontal geophones are also noisy, but shear wave events are detected on the prestack data. It appears that mode conversion from P to S waves is taking place and that the sea floor sensors are recording S wave energy. These preliminary results indicate that 4-component acquisition is a viable acquisition technology, even in very shallow water environments.

## Introduction

Transition zone and shallow water seismic acquisition is of particular importance in Brasil, which has an extensive coastline containing many producing and prospective basins. We can define the shallow water environment as that stretch of water, typically along the coast, but also inland seas and lakes, in which the water is deep enough to allow the use of hydrophones and marine sources throughout but is insufficient to permit operations of streamer vessels. The transition zone, on the other hand, can be defined as any area that requires the use of both land and marine acquisition techniques. The equipment and methods required to operate in these environments are very different from those required to work in deeper water depths, where the ambient pressure exerts more stress on the seismic equipment. A number of techniques have been developed to operate in these environments and they can generally be classified into two categories: Surface deployed systems and bottom-referenced systems. In the former, the electronic equipment sits on floats on the surface and the sensor is deployed beneath it. In the latter, the majority of the line electronics is deployed on the sea floor. Surface deployed instruments include the Telseis and the Box systems. They typically use radio telemetry to transmit the data to a central recorder, or store the data within the unit for later retrieval. Conventional OBC is an example of a bottom-referenced system, which uses telemetry through the cable to transmit the data to the central recorder, However, these are typically too bulky to operate in shallow water and cannot extend through the transition zone. Bay cables are also bottom referenced but are typically spidered to surface electronics. While they can be used through to land, they carry an analogue signal and suffer from the inherent amplitude degradation.

A third bottom-referenced methodology has been developed specifically for the shallow water and transition zone. This involves marinising traditional land systems to enable them to be fully submerged to water depths of up to 50m. These systems can progress seamlessly from shallow water, through the transition zone and onto land. Furthermore, they allow similar flexibility to land system, and stations can easily be offset to avoid reefs, mangroves or other sensitive areas.

## Transition Zone Acquisition Techniques

Grant Geophysical introduced its Transition Zone technology into Brazil by acquiring a survey for Devon Energy (then Santa Fe Snyder) in 1999. The survey included both shallow water areas and a land program, with continuous receivers deployed through the surf zone in between. The maximum water depth encountered was 15m and so the project was ideally suited for the use of a bottom-referenced, marinised land cable telemetry system. On this occasion, an Input Output System II was used.

The shallow water region in northeastern Brazil is relatively benign, with a maximum tidal range of approximately 3m during the spring tides. The sea floor is shallow out to several kilometers from the shore. Weather conditions are reasonable throughout the year, although waves can reach up to 3m in height during the months of August and September. The surf zone is the main obstacle encountered, due to the noise induced on the spread by the surf itself. In order to mitigate this noise, hydrophones were deployed in drilled holes. Throughout the shallow water and transition zone regions, the recording equipment was deployed from custom-built pontoon boats, with a draft of just a few inches.

In 2001 a second survey was acquired for Devon Energy followed by a 2D survey for Petrobras. On these occasions, the projects consisted entirely of shallow water acquisition, with no shothole drilling or land receiver requirements. Nevertheless, these surveys also suited the use of bottom-referenced, marinised land equipment, due to the need to deploy spread as close to the shoreline as possible. For the latest projects, an Aram 24 recording system superseded the I/O II.

For all three surveys, the marine portion was acquired using an array of Sodera's GI airguns. These guns differ from traditional airguns in that they do not use arrays to minimise the effect of the bubble oscillation. Rather, each gun consists of two chambers, the Generator and the Injector. At a certain moment after ignition of the Generator gun, when the primary bubble approaches maximum extension, the Injector is fired, sustaining the internal pressure within the bubble and allowing a gentle collapse. Thus each gun controls its own bubble oscillation. This system is very appropriate for use in TZ/SW as the array can be small and compact without losing the benefit of bubble suppression.

### Dual Sensor Summation

An additional benefit of bottom-referenced TZ/SW recording is that as receivers are deployed on the sea floor, velocity sensors may be used in addition to pressure sensors. This allows us to record the P-Wave velocity field and combine it with the pressure field to minimise water column reverberations. This is one of the primary advantages of bottom-referenced systems. As the returning energy arrives from the subsurface, it is recorded as an up-going wavefield by the sensors. However, much of the energy continues up through the water column and reflects back down from the air/water interface. Thus the energy reverberates through the water column, experiencing a 180° phase rotation each time it reflects from the surface and some amount of attenuation, proportional to the sea-floor reflectivity, each time it strikes the sea floor. These reverberations interfere with the primary up-going signal, introducing frequency notching and multiple problems into the data. The hydrophone is a scalar pressure sensor and so it records the sum of both the up-going and down-going wavefields. The geophone is a vector velocity sensor and records the down-going wavefield with an opposite polarity to the up-going wavefield. By combining the two datasets after the appropriate conditioning, it is possible to reduce the receiver side water bottom reverberations.

### Experimental 4-Component Acquisition

Once sea-floor velocity sensors are in use, it appears a relatively simple extension to add horizontal geophones to the vertical geophones and test for the presence of P-S converted waves. 4-component acquisition, as it is called, has become more prevalent in recent years, with the requirement to obtain ever more information from the seismic data. By interpreting shear wave data in addition to P-wave data, some imaging problems can be overcome and more quantative information can be extracted from the seismic data. Unlike on land, we cannot easily produce shear waves in marine environments and therefore we try to record shear data that has been converted from P-wave energy

In collaboration with Petrobras, Grant decided to test the use of 4-component sensors in the coastal region of the Potiguar basin. The objectives of the test were twofold. Firstly, we wanted to identify the operational techniques required to acquire 4-component data in the very shallow water environment. Secondly, Petrobras wanted to acquire a test dataset in order to develop their understanding of this technology and to determine if particular formations with poor P-wave impedance contrasts can be detected on the converted wave data.

With limited receiver equipment available, the test design relied on wide receiver spacing but a high source density to provide sufficient sampling. Cables were manufactured with two sets of sensors, each separated by 120m, allowing a group interval of 100m between deployed sensors. The total spread length of one patch consisted of 96 channels over 2.3km. Airgun sources were fired every 12.5m up to an offset of 2.5km either side of the cable. Two orthogonal lines were acquired, each line consisting of three patches. The lines varied in water depths of between 2m and 8m. The tests were conducted over a four-day period that coincided with the largest tides of the lunar month. These tides are associated with the roughest sea conditions and wave heights of up to 2m were present during some of the acquisition.

While the sensors themselves are fully gimbaled, ensuring that the individual elements always achieve the correct orientation relative to the others, recording the orientation of the entire unit is vital during 4C acquisition. Conventional OBC achieves this by aligning the sensors along the cable and dragging the cable into position. This method is not appropriate to our environment, where the cables are often deviated around reefs or other obstacles. In 3D acquisition, vector fidelity is often determined post acquisition, by analysing the direct arrivals on each component. Again, this method is difficult in very shallow water, where receivers record direct arrivals from comparatively few nearby shots. Therefore, a hybrid approach was used, in which the sensors were oriented along the cable, which was kept taut enough during deployment to maintain direction without dragging. Simultaneously, the heading of the deployment boat was recorded. These results will then be compared against the orientation indicated by a combination of direct arrival and first break analysis.

**Preliminary Results**

The two 2D lines were successfully recorded, although the acquisition technique did place some stress on the 4C cables. Deployment of the spread was somewhat slower than during routine production, due to the additional care required to orient the sensors. The raw shot gathers looked very unpleasant, given the long offsets, mixed receiver types and wide sampling. The shallowest receivers showed strong noise bursts throughout the record length. It was difficult to visualize any data being acquired looking at the raw shot gathers. However, once the data were loaded onto the field processing system and transformed into common receiver gathers, the signal could clearly be seen and the quality of the hydrophone data appears similar to the previous single hydrophone data. The vertical geophone receiver gathers also showed much better data than expected, particularly on receivers outside the surf zone. Finally, both the radial and transverse geophone raw receiver gathers showed some apparent shear wave data, providing encouragement that PS mode conversion is taking place and that those shear events are being detected by the bottom-referenced sensors.

**Further Developments**

The next stages of this project will involve further analysis of the seismic data. Firstly, the vertical geophone and hydrophone data will be combined to produce a dual sensor stack. Secondly, direct arrival and first break analysis will be used to determine the sensor orientation. This result will be compared with the deployed orientation records to calibrate the accuracy of the methodology. It may be that different operational techniques are required to improve the orientation determination. Finally, the data will be analysed further for the presence of shear waves, and converted wave processing will be conducted.

**Conclusions**

Acquisition techniques for shallow water and transition zone environments have been developed that are well suited to operations in the littoral regions of Brasil. These techniques have been extended to include the possibility of acquiring dual sensor and 4-component data, even in the very shallow waters along the coast. In the Potiguar basin, mode conversion does appear to occur and the S-wave energy produced can be detected through shear wave velocity phones deployed on the sea floor. However, much work remains to be done in refining both the acquisition and processing of these data.

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# Sistema Integrado de Segurança, Meio Ambiente e Saúde no Serviço de Aquisição Geofísica da PETROBRAS

*Durval Borba Bittencourt Jr., Marcus Petracco Marques e Paulo Roberto de Azevedo, PETROBRAS S/A, Brasil*


## Abstract

O Serviço de Aquisição Geofísica da PETROBRAS (E&P-NNE/SAG) implantou um Sistema de Gestão de Segurança, Meio Ambiente, Saúde e Qualidade (SMS) e obteve as certificações ISO 14001 (meio ambiente) e BS8800 (segurança e saúde). A criação de novas leis, aumento da responsabilidade social, diretrizes corporativas da PETROBRAS e um histórico de acidentes, danos ambientais e passivos com explosivos na aquisição sísmica terrestre levaram o E&P-NNE/SAG a adotar este sistema de gestão. Através do SMS foi realizada a avaliação dos riscos, padronização de processos, melhoria no modo de operação, desenvolvimento de ferramentas de gerenciamento e estabelecimento de objetivos e metas a médio e longo prazo. Como resultado tivemos a redução dos acidentes, menor impacto ambiental, melhor satisfação de partes interessadas (clientes, comunidades, proprietários rurais, contratados, empregados, etc.). O SMS do E&P-NNE/SAG com 2 anos de certificação pela empresa Det Norske Veritas e acreditações internacionais RAB (Register Accreditation Board - EUA) e RvA (Raav Voor Accreditation - Holanda) continua como pioneira no mundo na obtenção do certificado ISO 14001 para equipes de aquisição de dados geofísicos


## Introdução

O E&P-NNE/SAG recebeu em julho de 1998 o prazo de um ano para a implementação do Sistema SMS e se possível a certificação pelos critérios da ISO 14001 e atestado de conformidade segundo a Norma Britânica BS8800. Para a implantação foi contratada a empresa de consultoria Bureau Veritas (BV), que prestou consultorias de 1 dia cada mês e também promoveu treinamento sobre as normas de referência e formação de auditores internos. Em julho de 1999 o sistema foi considerado implementado, quando foi iniciado o processo de avaliação através da empresa certificadora Det Norske Veritas - DNV (Figura 2). O processo de certificação foi concluído em 02/09/1999, com a obtenção da certificação ISO14001 com acreditação INMETRO (Brasil), RvA (Holanda) e RAB (Estados Unidos), além do atestado de conformidade BS8800 expedido pela DNV. Esta certificação tem validade de 2 anos sendo avaliada semestralmente através de auditorias de manutenção realizadas pela DNV.

Vários fatores motivaram a implementação do SMS no E&P-NNE/SAG, entre os quais:

- necessidade de melhoria do sistema de gestão empresarial;
- cenário competitivo do final da década;
- exigência dos clientes internos da PETROBRAS;
- risco inerente à atividade e histórico de acidentes;
- passivos ambientais;
- necessidade de padronização de processos.

## . Implantação do Sistema de SMS

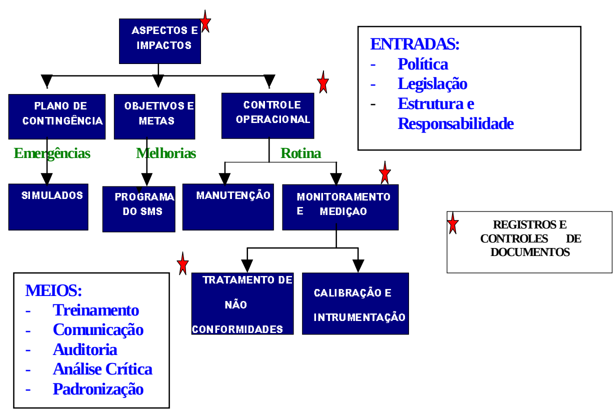
O sistema SMS do SAG foi baseado no modelo do E&P/CORP, sendo adaptado às peculiaridades locais. Para a implantação do sistema foi definido um Representante da Administração (RA), com a função de implementar o SMS e reportar a gerência o desempenho do mesmo. O SAG definiu que o RA seria desempenhado por um Comitê de SMS. Outros comitês foram criados nas unidades operacionais (Equipes Sísmicas), otimizando a comunicação e disseminando os requisitos do sistema. Todo o processo é baseado no ciclo PDCA (planejar, desenvolver, checar e analisar criticamente), onde os requisitos normativos são desenvolvidos e acompanhados de forma dinâmica. Os requisitos mínimos exigidos pelo sistema são:

1. Política: declaração formal do comprometimento da gestão com os propósitos do SMS.
2. Aspectos e Impactos: análise minuciosa e contínua de todas as atividades, produtos e serviços, identificando os aspectos que possam causar impactos, considerados significativos, ao Meio Ambiente à Segurança e à Saúde dos trabalhadores. A avaliação dos aspectos e impactos é a base de todo o sistema (Figura 1-Fluxograma do SMS).
3. Legislação: identificação de toda a legislação aplicável, incluindo normas técnicas internas e externas, requisitos de clientes e contratos. A legislação aplicável foi condensada em uma lista mestra, com procedimentos padronizados para a contínua atualização. A lista mestra foi disponibilizada na “home page” do SAG e a consulta do conteúdo das legislações é realizada através do LEX AMBIENTAL (site contratado pela PETROBRAS).
4. Objetivos e Metas: foram definidos a médio e longo prazo, tendo como fonte a política,

levantamento de aspectos e impactos, requisitos legais, metas corporativas, tratamento de não conformidades, demanda de partes interessadas, orientações corporativas, etc.

5. Programas: foram estabelecidos programas para o atendimento dos objetivos e metas, todos com cronograma, responsáveis e recursos necessários.
6. Estrutura e Responsabilidade: foi reavaliado o organograma interno, sendo redefinidas as responsabilidades desde a gerência até os empregados.
7. Treinamento, conscientização e competência: a partir da política, gerenciamento dos aspectos e impactos significativos e objetivos e metas, foi definido um programa de treinamento para todos os empregados. Para auxiliar o gerenciamento do treinamento foi desenvolvido um programa em "Access" denominado TREINAR, disponível via intranet, com tecnologia de 3 camadas (atualização em tempo real).
8. Comunicação: foi redefinido o fluxo de comunicação entre o SAG, unidades operacionais, clientes e partes interessadas (comunidades, contratados, proprietários de terra, etc.). Todas as comunicações são recebidas e através de um procedimento específico é avaliada a pertinência e a resposta adequada.
9. Controle de Documentos: foram definidos procedimentos para a elaboração e controle de documentos, de forma que possam ser localizados, periodicamente revisados, mantidos atualizados e prontamente substituídos em caso de alterações. Para facilitar o controle foi adotada a padronização proposta pelo E&P, através do sistema corporativo SINPEP (Sistema Integrado de Padronização do E&P).
10. Controle Operacional: através do levantamento de aspectos e impactos foram definidos procedimentos que assegurem que as operações sejam executadas em condições seguras/controladas e dentro de critérios. Estes procedimentos são extensivos aos prestadores de serviço e fornecedores e incluem as atividades de manutenção.
11. Planos de Contingência: as hipóteses acidentais foram identificadas através do levantamento dos aspectos e impactos e os acidentes e as situações de emergência foram contemplados nos planos de contingência. Os planos de contingência são disponibilizados em todos os locais de trabalho e são realizados simulados.
12. Monitoramento e medição: foram estabelecidos procedimentos para monitorar e medir periodicamente as características principais de suas operações e atividades com impacto significativo e relacionadas com os objetivos e metas.
13. Não-conformidade: foram definidos procedimentos para a identificação e classificação de anomalias ou não-conformidades. Também foram definidas as formas de registro, implementação das ações, responsabilidades e acompanhamento. Para o gerenciamento deste processo é utilizado o sistema corporativo SIGA (Sistema Informatizado de Gerenciamento de Anomalias).
14. Registros: a identificação, manutenção e descarte dos registros foi sistematizada, de forma a permitir a sua pronta recuperação e conservação.
15. Auditorias Internas: a verificação da implementação e funcionamento do SMS de acordo com as referências normativas é realizada através de auditorias internas. Estas auditorias dão subsídios para a gerência realizar a análise crítica.
16. Análise Crítica: é realizada para a verificação da efetividade do sistema e o cumprimento da política. São realizadas reuniões trimestrais, com a participação da gerência, comitês de SMS e convidados.

**Figura 1**: Fluxograma do SMS




## Resultados

Como benefícios da implementação do SMS e da certificação tivemos:

- incorporação do SMS na gestão do negócio;
- estabelecimento de metas a médio e longo prazo;
- conhecimento e cumprimento da legislação;
- melhoria das relações com clientes internos;
- facilidade na obtenção de licenças ambientais;
- redução do número de acidentes e não ocorrência de acidentes fatais;

- diminuição de reclamações de partes interessadas;
- padronização dos processos;
- estabelecimento de Carta Acordo com as Unidades de Negócio clientes (UN-BA, UN-ES, UN-SUL, UN-SEAL) e fornecedores (Compartilhado/NNE);
- otimização de insumos e adequada destinação final dos resíduos
- redução do impacto ambiental;
- maior controle sobre a sáude ocupacional.

Podemos observar nas Figuras 3 e 4 a evolução histórica (1996 a 2000) do número de acidentes típicos com afastamento e da taxa de frequência de acidentes típicos com afastamento (TFCA), e o resultado após a implantação do SMS.

**Figura 2**: Curva S da implantação do Sistema SMS

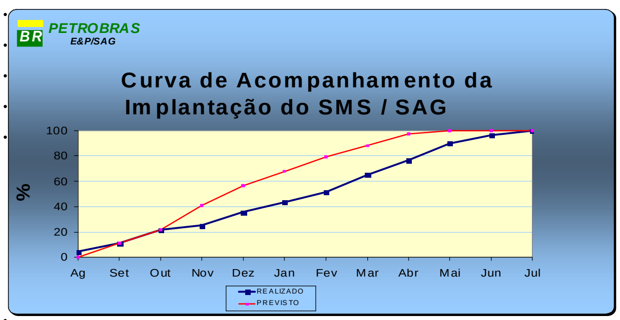



**Figura 3**: Número de acidentes típicos com afastamento

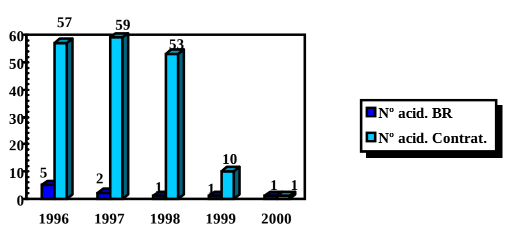
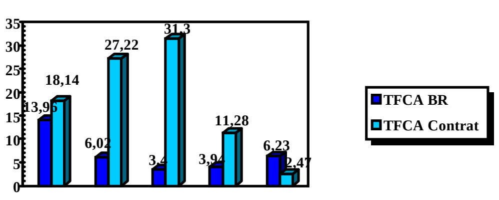



**Figura 4**: Taxa de frequência de acidentes típicos com afastamento




**Conclusões**

A implementação do Sistema SMS adequou o SAG aos requisitos corporativos da PETROBRAS e às exigências do mercado. Através do SMS ocorreu uma melhoria na gestão do negócio, com resultados positivos nas funções segurança, meio ambiente e saúde ocupacional.

O SAG é pioneiro no mundo na obtenção do certificado NBR ISO 14001 para equipes de aquisição de dados geofísicos, mantendo a tradição da aquisição através da sua equipe escola (ES-26).

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**Agradecimentos**

Agradecemos a PETROBRAS pela oportunidade de divulgação deste trabalho e a todos os empregados do E&P-NNE/SAG, que com espírito de colaboração, criatividade e engajamento possibilitaram a mudança de cultura e a implantação do SMS

**Staged 3D Seismic Surveys**
*Elias Z. Ata, PDVSA, attae@pdvsa.com*


## Summary

A practical and economical approach to geophysical exploration is proposed to optimize the design and lower the cost of 3D surveys, while significantly reducing data volume and environmental damages. The 3D optimization can be achieved by staged acquisition, through integrating exploration, development and production surveys in a regional framework of sub-surveys in a single design. In the exploration stage, a sparse regional 3D survey will allow successful identification and drilling of the promising structures. Then, a development 3D survey will fully use the previous design to complement the sparse data over the discovered fields, where needed. And lastly, a production survey will use needed data from both previous 3D surveys, together with new 3D data, to yield an even higher resolution and quality datasets. Such surveys consist of sparse 3D surveys with large source and receiver line spacing that are nested, or inter-fingered such that finer line spacing can be attained progressively with each stage. The final survey should yield equivalent or better results to those desired from a conventional 3D survey (line spacing as well as bin size). This approach can introduce greater flexibility in the deployment and implementation of acquisition, in addition to a sizable reduction in the volume, cost and environmental damages over conventional seismic surveys.


## Introduction

The subject of optimization 3D seismic data has been an important focal point to minimize cost and environmental damages, yet maintain the integrity of such data (Wombell, R et al. 1999, Wloszczoeski, D. et al, 1998, Vincent, B. Et al, 1999). Many existent 3D seismic surveys, acquired over the life span of a reservoir, have been integrated in a single volume and used effectively as a unified dataset (this practice includes merged prestack or poststack 3D datasets). Considering the high quality results obtained from such practices, and the latest developments in recording equipment (number of channels, DRD…etc), future 3D surveys can be designed to fit and complement past surveys. Such approach helps to increase fold, complement coverage area and improve overall quality (higher S/N and better offset and azimuth distributions).

As in any 3D survey, subsurface images are more technically reliable and economically viable in the long run than any 2D survey. In exploration areas, 3D surveys increase the probability of locating hydrocarbon-bearing structures and improve the success rate in localizing and perforating productive wells. Sparse 3D surveys can be designed on a regional scale with wide source- and receiver-line separation such that all later development and/or production surveys can make use of the previous data. The idea is illustrated in Fig.1, where the blue, red and green surveys indicate the regional or exploration, the development and the production surveys, respectively. Assuming a source line spacing (SLS) of 1-1.5 Km for the first stage survey (exploration), then with the development stage survey, the SLS becomes 500-750m. and at the production stage, this SPS reduces to 250-375m. In the same context, assuming an initial bin size of 50x25m (shotpoint spacing is double the receiver spacing) with the first survey, the bin size can be reduced to 25x25 in the second, and to half that, if necessary, in the next survey. Receiver line spacing (RLS) as well as receiver spacing (RS) must be maintained within the limits to prevent special aliasing and yield sufficient fold.

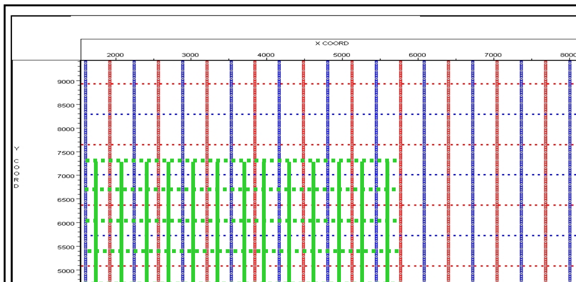

Figure 1. Staged 3D surveys where the blue represents the exploration survey, the red the development survey and the green the production survey. Note that SLS as well SPS are double of the RLS and RS.

The optimization approach provides a substantial reduction in the cost of seismic data over the life of the reservoir. The large SLS and RLS spacing allow for extensive parameters that yield higher quality data in the shotpoint domain. In explosive surveys, deeper shot holes can be deployed to attenuate surface waves, while in vibroseis surveys, longer sweeps and more vertical summing can be utilized to improve S/N ratio. An advantage of the large separation between source and receiver lines (1 to 2 km) is that problematic areas might be avoided and environmental damages can be substantially reduced. Here we present two case histories, where this optimization approach was used: in the first, to improve data quality and complement missing data, and, in the second, to map and develop another complex field in the same area.

## Case 1

The oil field “El Bosque” is located in the huge subsurface over-thrust complex of “Norte de Monagas”, in Southeastern Venezuela. The complex geological model had been grossly estimated from various 2D and 3D surveys acquired in the area since 1986. For various limitations in 3D acquisitions and 2D deficiencies in complex areas, all datasets have failed to image the structure beneath the hanging-wall of the "Pirital" thrust. For delineation and development purposes, more reliable subsurface images were critical for a successful well-perforation program. Although the cost of seismic is very high, the average cost of one production well surpasses the cost of a 200 $Km^2$ 3D seismic survey as the one shown in Fig.2.

The "El Bosque" oil field is also an extremely difficult seismic record area (Del Pino, E. et al. 1992). The poor quality is mainly caused by the inhomogeneous near-surface (attenuation, source and receiver coupling), very strong back-scattered refractions and surface waves, large areas of rough topography, the outcropping of the overthrust and the complexity of the subsurface geology. In addition, cultural noise (agriculture, traffic and residential areas) and the problems associated with access caused by natural obstructions and land permits cause further deterioration of the data.

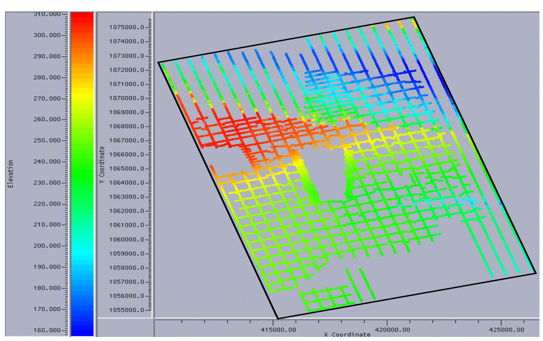

Figure 2. Map of a 3D survey with the skipped source and receiver points missing inside the intended aquisition area enclosed within the rectangle. Colors indicate elevations.

Fig. 2 shows the minimal intended design to meet the survey's objectives, versus the actual survey that was acquired over the "El Bosque" field. The intended area for full coverage is enclosed by the rectangle with source lines oriented E-W and receiver lines in N-S direction. The areas in the southeast, center and southwest have been skipped for lack of access permit and/or residual and industrial constructions. The northwest area of the survey is a national park, therefore, the spread was limited to receiver lines, and no sources were permitted. While in the center, the southeast and the southwest, neither sources nor receivers were permitted due to lack of land access permits. The challenge therefore, was to acquire quality seismic data as well as to later fill in missing data areas from vintage surveys.

In order to salvage the survey and meet the objectives of the project, the feasible solution was to integrate the new design in the 1992 3D survey. Fig. 3 illustrates the survey extents after recovering the missing data in the 98-survey from the 1991-2 surveys. It can be observed that both vintage surveys are closely spaced and much more source intensive than the 1998 survey (500m vs. 300m). Another distinctive characteristic between the old surveys and the 1998 survey are the source efforts and type (vibroseis vs. dynamite), the offset range (3500 vs. 6500m.), the fold (2800-7200%), the number of traces per shot (480 vs. 2000), the aspect ratio (.6 vs. .9) and the overall quality of the data. It was very important to obtain enough migration apertures for the steeply dipping Pirital thrust, which requires offset range to 6500m. Examining the range of offsets between the previous and 1998 survey, it was decided that a meaningful incorporation of the old and new data could be achieved at pre-stack level to obtain good quality data as seen later in the results.

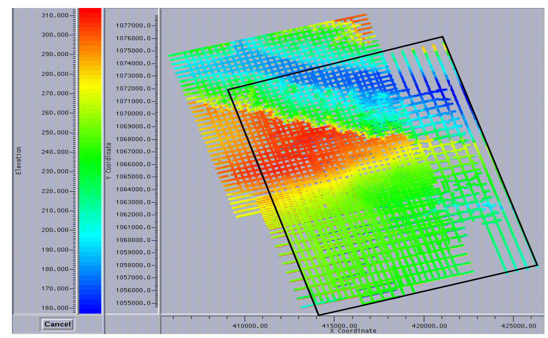

Figure 3. Map of the resultant 3D survey after replacing the missing data in 1998 with the 3D data acquired in 1991 and 1992. The area enclosed in the black rectangle is the original intended area of acquisition.

## Case 2

In a development and delineation project for another complex oil field in "Norte de Monagas", three 3D surveys were used to complement each other and provide sufficient migration aperture of the structure shown in Fig.4. Each of the surveys was recorded independently at different times and with different objectives. The geometry and the bin size varied from 20x30m.in the West, to 25x25 in the center, and to 30x30m. in the Northeast. The sources consisted of vibroseis in the west, explosive, fairly deep shot holes in the center, and shallow shot holes in the Northeast. The unified geometry and the fold map obtained from the interpolated survey of 20x20m are shown in Fig. 5. The three datasets were phase and amplitude corrected, then processed through the last residual/velocity analysis iteration on their natural grids. DMO corrections were then performed on a 30x30m unified grid. Prior to migration, the 30x30 grid was interpolated to obtain a unified 20x20m. grid. This stack volume was time migrated and the results are shown below.

## Results

From case 1, Fig. 6 shows a NW-SE profile that bisect the area of the survey in the center (Fig. 2) before incorporating the vintage data of 1991-2 surveys. In contrast, Fig. 7

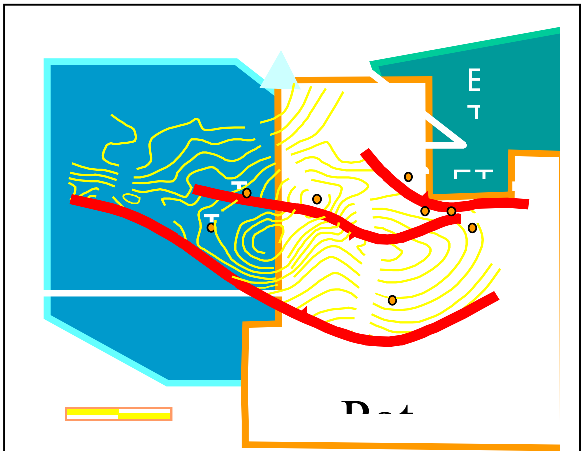

Figure 4. Map of the three different 3D surveys that were used to map the extent of the structure delimited by the two faults in the south. The blue and the orange surveys were shot in 1998 with vibrators and explosives respectively, while the green survey was recorded with explosive sources in 1992.

shows the same profile as in Fig.6 after incorporating the missing data from the vintage surveys. With the zone of interest right below the large skip in the center of the survey, the objective could have not been attained without the complement of the 1991-2 surveys, in spite of the inferior quality of these surveys. The profile shown in Fig.6 is a preliminary stack, as no advantages could be perceived by producing a final stack without recovering the missing data. To maintain the comparison in perspective, the profile shown in Fig.7 is also preliminary and does not represent the final quality of the data.

In the second case, Fig. 8 shows an E-W profile which is highlighted by the blue line in Fig 5, and which crosses the 1998 and 1992 surveys where indicated by the black lines in Fig.8. No differences can be observed where the limits meet or overlap as outlined by the two black lines. An examination of Fig.8 reveals that the data quality in the north side of the profile is inferior to the data quality in the south (92 vs. 99 acquisition). This difference could have resulted from the limitation in acquisition systems in 1992. A partial survey that can complement the missing data could be acquired with a sizable saving of time and resources. The interpretation of this volume allowed the spotting of three delineation wells of which one productive well has been drilled.

The normal approach to a project similar to the one presented here is to acquire a new 3D survey, in which case the cost of such a survey, at a moderate rate of $1,000 per shot, can easily exceed $15MM. On the other hand, the cost range of the 1998 survey was only $7MM. In addition to this economical advantage, the acquisition and environmental damages were completely avoided.

## Conclusions

The two case histories previously presented lead us to conclude that staged and integrated seismic 3D surveys can be fitted as subsets in a regional initial survey. Exploration begins with a regional 3D that replaces all 2D exploration surveys, so economically sound plays can be located and drilled successfully. As the need of more seismic 3D arises in the development and exploitation stages of the reservoir, a localized 3D-survey can then be fitted as a subset of the previous survey in order to complement the previous 3D sparse data. This method can present massive reductions in environmental damages due to reduction in the intensity of source positions, the wide source line and receiver line spacing, and the staged acquisition over a period of several years. This methodology provides a sizable reduction in the cost of 3D seismic, optimizes the area of coverage, compensates for the use of better acquisition parameters and geometry, and reduces environmental damages and cost of land permits.

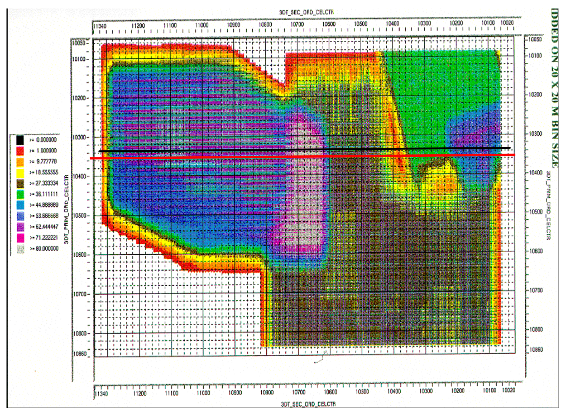

Figure 5. Coverage and fold map of the combined three 3D surveys. It can be observed that the necessary overlap between the western and central surveys was exceeded while the overlap between the central and northeastern surveys was not sufficient.

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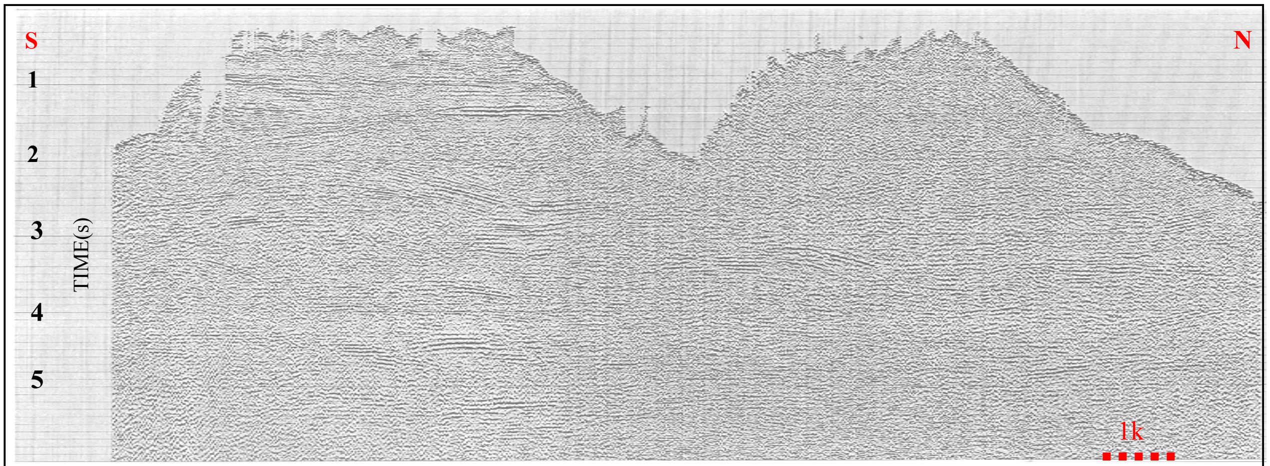


Figure 6. A N-S profile through the center of the area Bosque 3D survey before incorporating the data from the 1991-2 3D surveys.

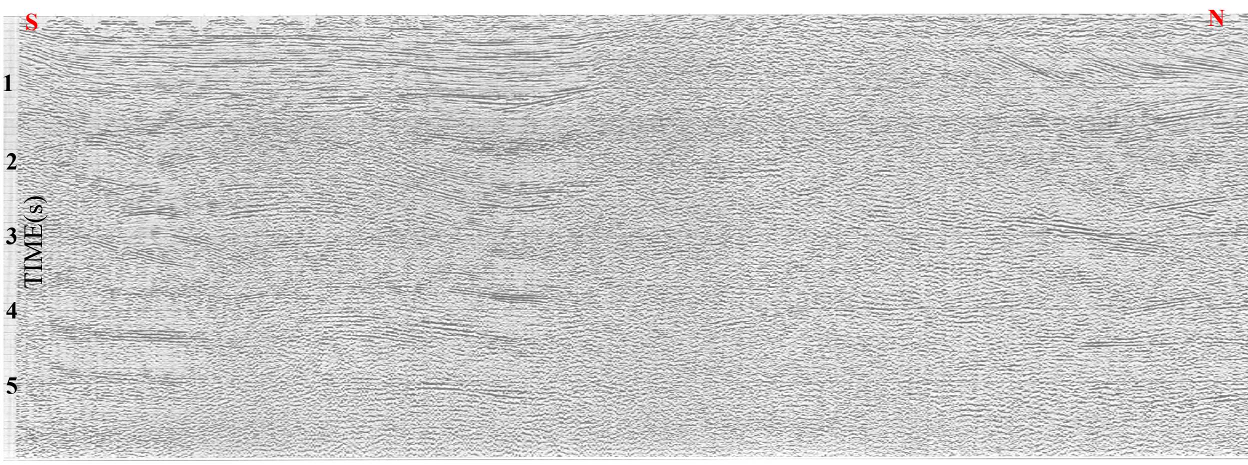


Figure 7. Same N-S profile as in Fig.6 after incorporating the data from the 1991-2 3D surveys. Note that this profile is referred to a datum.

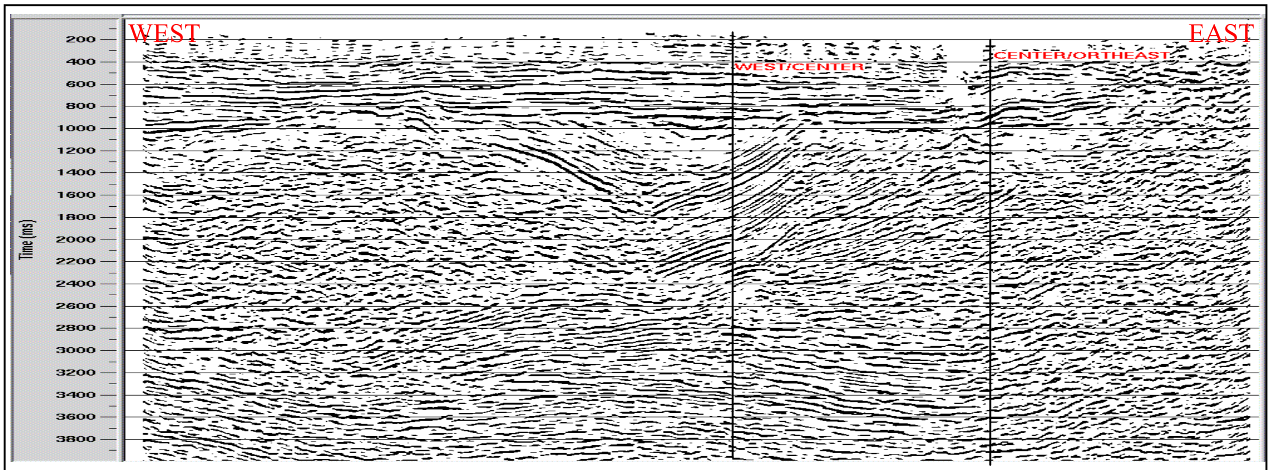


Figure 8. This profile was taken from the volume of case 2. The line crosses the both surveys 1998 and 1992. The noticeable differences between the N and S ends of the volume are due mostly to geological factors, another factor can be related to the difference in the parameters and equipment between the 1998 and 1990 data. The vertical line indicates the limits of both surveys.

# Transition Zone (TZ) Seismic Acquisition, Opening New Frontiers along Brazilian Coastlines

*Allan E Kean, Geophysical Consultant, El Paso Production Co./Coastal Corporation*

**Abstract**
Transition Zone (TZ) seismic data acquisition occurs in areas where the land crews finish their work and the marine crews begin theirs'. In the TZ, problems arise from equipment limitations, the logistics of operating in water as well as on land, and crew requirements necessary for deployment of equipment in both environments. These are a few of the contributing factors to an increase in technological difficulties associated with TZ seismic data acquisition. These technical difficulties result in operational problems increasing the acquisition cost per kilometer and causing degradation in the TZ seismic data quality.

The ongoing conversion of natural gas into electricity with turbines coupled with an increase in demand for electricity has resulted in an increase in demand for natural gas. As the "gas bubble" has burst in the USA, where the low price for natural gas was related to an overabundant supply of gas, a higher price for natural gas is now being realized. All this plus the merger of large oil and gas companies into "Mega" companies, has resulted in a niche being created for companies interested in a natural gas exploration strategy, particularly in areas where it is more difficult to explore, such as the Transition Zone.

**Introduction**
When the hydrocarbon potential of an area is large, the development of the appropriate seismic technology needed to explore will occur. This has been the case in the Transition Zone. As discoveries continue to be made and as industry moves further offshore, historically technology has risen to meet the challenges of these harsh environments. Traditionally in the TZ environment, waterproof bay cables were used similar to the cables used onshore. These bay cables were connected to hydrophones or waterproof geophones with extra long spikes for planting into unconsolidated water saturated sediments. Today, Ocean Bottom Cables (OBCs) are used to increase productivity where bay cables proved to be not as operationally productive. In addition to the added expense of the OBC cable, additional ocean going vessels are required to deploy the cable, the hydrophones and for the recording of the data. This same equipment must be transportable to the shore for operations there, or an additional set of equipment would be required.

**TZ Operational Costs**
In general, the level of technical evaluation effort and notoriety placed on the transition zone compared to the shelf and deepwater has not developed. The reasons are that TZ seismic data acquisition takes more time for an equivalent number of kilometers than any other acquisition area and it costs more. It costs approximately twelve times more for TZ acquisition than other entirely marine 2D acquisition, and it is about twice as expensive as 3D and onshore acquisition as shown in Figure 1. Seismic acquisition is harder and more expensive in the Transition Zone, because of equipment and manpower requirements and the challenges of operating amphibiously. As discoveries are increasingly harder to make worldwide, the Transition Zone's future becomes brighter, as an overlooked area due to cost, logistics, etc....

**Exploration Potential**
The margins on both sides of the Atlantic Ocean have produced large amounts of hydrocarbons for over 30 years. Areas like the North Sea, the Scotian Shelf, the Niger Delta, the Congo River, and the Campos Basin, are just a few examples of the largest producing areas. These areas also have production from the Transition Zone as shown in Figure 2. All of these areas have most recently become well known because of deepwater discoveries. However, it was the past exploration histories in the shallow water that began the exploration efforts and led exploration, appraisal and development programs to where they are today. Established petroleum systems, capable of generating large volumes of hydrocarbons, were first discovered with shallow water exploration programs. Onshore, then overstepping the Transition Zone into the shallow water shelf area and into the deepwater is the normal progression of hydrocarbon discoveries in most basins.

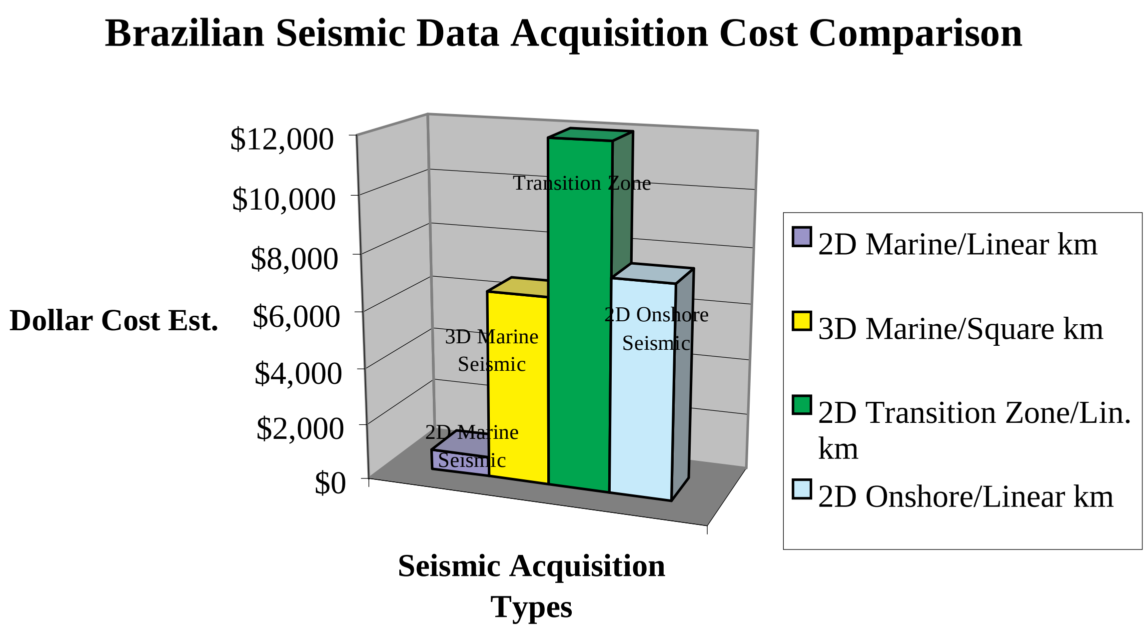


Figure 1: Cost Comparison Seismic Acquisition in various terrain (from recent job bids in Brazil).

In Brazil, the TZ is largely under-explored, offering upside potential to smaller operators and an industry focused on deepwater exploration and development. The TZ offers another avenue for industry growth and economic uplift to Brazil. Brazil’s exploration history is somewhat unique compared with other countries around the world. Petrobras after being successful in the shallow waters of the shelf discovered deepwater sediments with hydrocarbon accumulations. The TZ exploration and development niche however is not attractive to all companies. Geologically, the structural traps are generally smaller and the reservoir bodies limited in their areal distribution. This is attributed to the confined nature of the sediments found here as they are transported and first deposited into the marine environment, mainly as fluvial to deltaic systems. But as most geoscientists are acutely aware, depositional systems are dynamic. Where there once was deepwater deposition, today shallow water deposition may be occurring. This is how prograding systems work over the course of geologic time.

**TZ Niche Development**

In the wake of the “Mega-Mergers” of large oil companies (Figure 3), a new oil and gas industry is slowly emerging. As there are fewer, large companies in existence, a niche is being created for the smaller operators looking for areas to explore. Coupled with the bursting of the “Gas Bubble” in the USA, where prices have as much as tripled in the last year, present a unique opportunity for companies positioned to take advantage of it. In addition, OPEC is managing to be successful in their attempts at restricting production in order to keep oil prices as high as twice what they were a year ago. Surviving companies are realizing large profits, better cash flow and higher returns on investments.

Natural gas, as a cleaner burning and less costly energy has become the energy of choice for many people. However, there must be a market for the gas or at least the anticipation of a market in the future for this resource to be valuable. For many years, West Africa has been an area with large supplies of natural gas, but with no market to utilize it. Agrarian based cultures with little technological need for natural gas are instances where natural gas marketing has little value today. However, in large population centers, industrial and manufacturing complexes, and technically advanced societies, the uses and needs for natural gas will only increase. Once the market has been established the supply of natural gas will be the only factor in its way of becoming the energy of choice.

**Conclusions**

This paper concerns exploration for oil and gas in coastal areas of Brazil with seismic acquisition techniques suited for both shallow water and

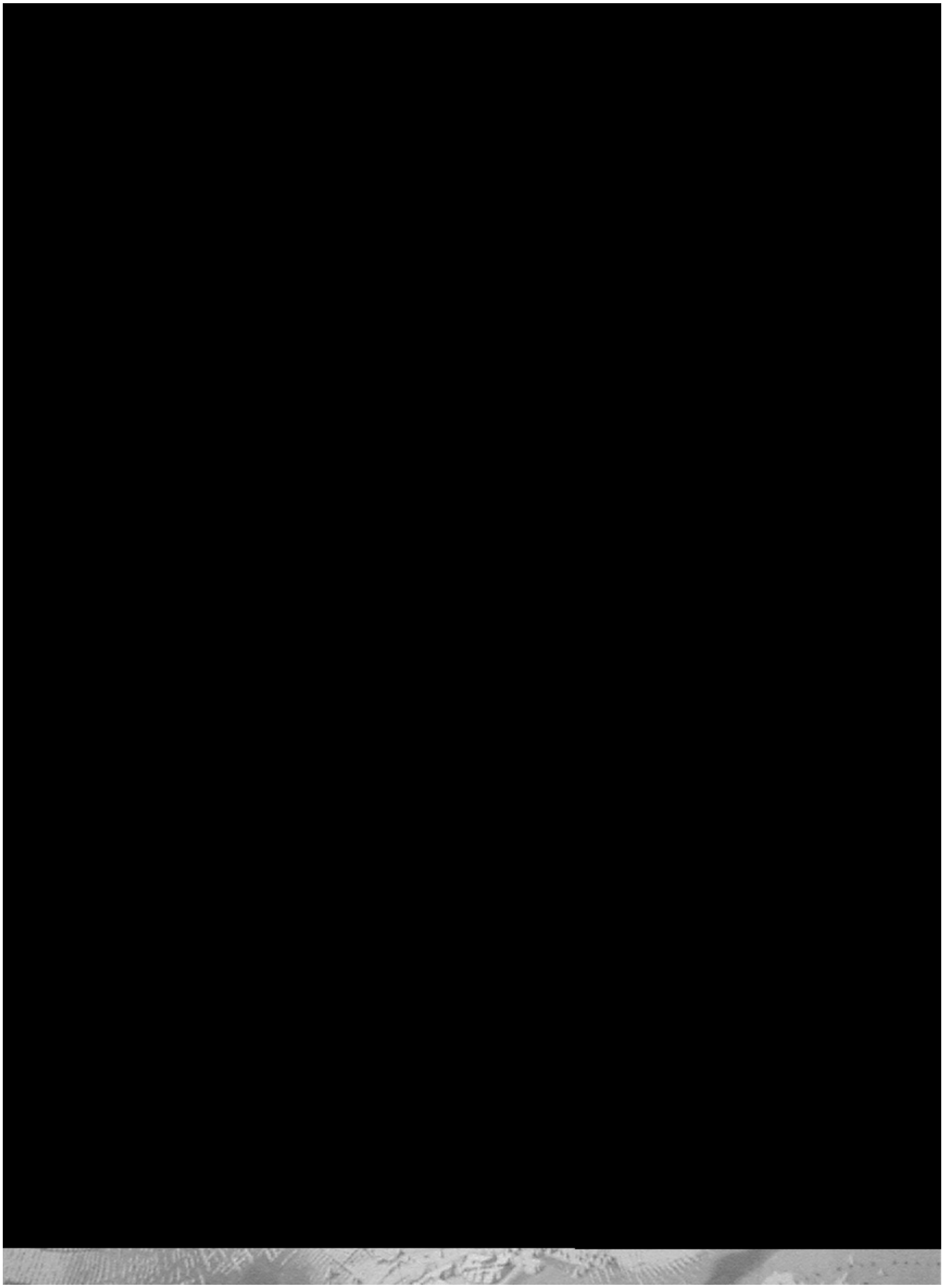

Figure 2: Recovered volumes of oil and gas from sedimentary basins around the Atlantic Ocean margin (After PetroConsultants 1996).

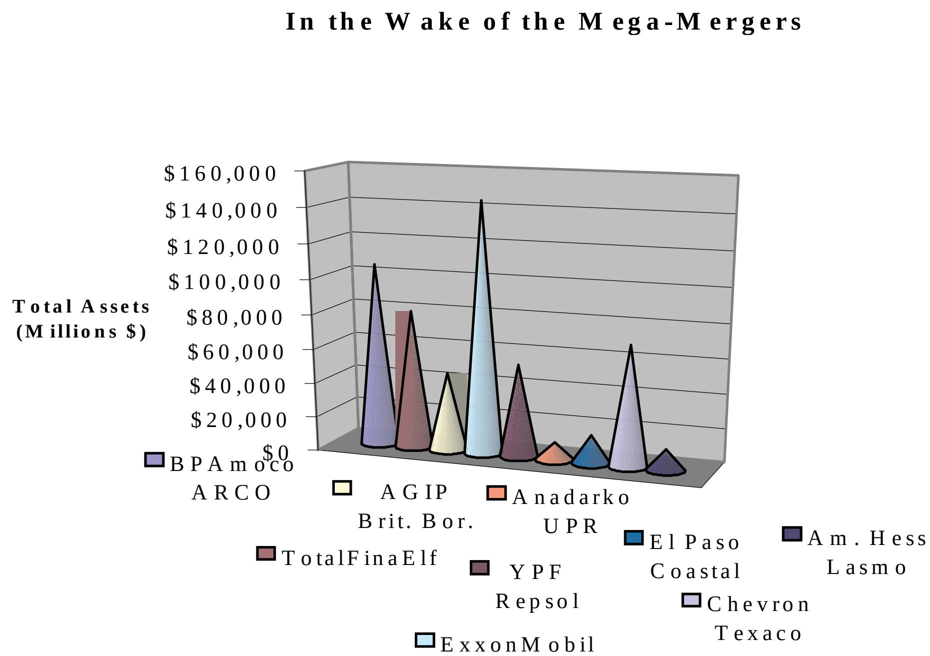


Figure 3: Mega-Merger Trend (After Oil and Gas Journal, Oct. 16, 2000).

onshore terrain. Brazil is one of the growing number of countries with more emphasis on deepwater reserves than those found near the coast. Brazil is also a place where little TZ data has been acquired.

El Paso/Coastal is participating in one TZ development project in the Camamu Basin with the BAS-97 Project. A TZ seismic data acquisition program is proposed for the spring of 2001. If successful in acquiring the appropriate environmental permits, a seismic data comparison may be available in time for this conference. Devon Energy has acquired two TZ surveys in the Potiguar Basin. Petrobras is also participating in a speculative TZ program. In addition to the development project, El Paso Production Company acquired three exploration blocks in the 2nd Bid Round, two in the TZ and one onshore. Sparse seismic data availability, coupled with poor data quality is a common thread in TZ exploration. Therefore, a company must effectively acquire TZ seismic data in order to explore in areas not looked at before in the surf zone transitional from the onshore to the offshore. To date there are no incentives for the acquisition of TZ seismic data in Brazil, as there are for 3D seismic data. As an incentive for stimulating exploration in the TZ, a work program conversion even larger than that given for 3D seismic (1 sq. km to 5 km conversion to 2D) is warranted for TZ data on a cost basis (see Figure 2).

El Paso/Coastal hopes that modern TZ seismic acquisition methods will help us unlock the hydrocarbon potential in this area. We also believe that the future is now for the TZ, particularly with the lead times necessary for discovery and development of oil and gas fields in Brazil.

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